Appendix A
GLOSSARY OF TERMS

APPENDIX A – GLOSSARY OF TERMS

AAM – Automatic Adjustment Mechanism

AcSB – Accounting Standards Board

AES – Alternative Energy Services, see also "Thermal Energy Services"

AES Inquiry Report – The Commission's Report on the Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives, BCUC Order G-201-12

AFUDC – Allowance for Funds Used During Construction, which is an allowance for the cost of debt and equity funding of capital projects before they are completed and placed into service and included in rate base; the AFUDC recorded for a project is added to the overall project cost

AFUE – Annual Fuel Utilization Efficiency

AIFR – All Injury Frequency Rate

AMR – Automated Meter Reading

Application – FortisBC Energy Inc. 2014-2018 Revenue Requirements Application

AUC – Alberta Utilities Commission

BC or B.C. – British Columbia

BC-AWE – BC All Weekly Earnings

BC-CPI – BC Consumer Price Index

BC Hydro – British Columbia Hydro and Power Authority

BCIT – British Columbia Institute of Technology

BCSA – British Columbia Safety Authority

BCUC – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia

BI – Business Intelligence, an IT Platform which stores the reporting, analysis and interpretation of business data

Biogas – Raw gas substantially composed of methane that is produced by the breakdown of organic matter in the absence of oxygen

Biomethane – Biogas purified or upgraded to pipeline quality

B&V – Black and Veatch

Capex – Capital Expenditures

CBOC – Conference Board of Canada

CCE Project – Customer Care Enhancement Project

CD – Contract Demand

CDA – Conditional Demand Analysis

CDOR – Canadian Deposit Overnight Rate

CEO – Conservation Education and Outreach

CGA – Canadian Gas Association

CHBA – Canadian Home Builders' Association

CMAE – Core Market Administration Expense, which are costs resulting from the management activities performed within the Gas Supply area to serve core market customers and are treated as a flow-through cost to core market customers as part of gas costs

CNG – Compressed Natural Gas, which refers to CNG Service for Natural Gas Vehicles

COC/TPP – Code of Conduct and Transfer Pricing Policy, which is a policy document approved by the Commission setting out the working relationships between FEI and non-regulated affiliates

Commission – British Columbia Utilities Commission, the provincial body regulating utilities in British Columbia

Company – FortisBC Energy Inc. or FEI

COPE – Canadian Office of Professional Employees

COS – Cost of Service, a term used in utility ratemaking referring to the total costs of providing a service, typically including operating expenses, depreciation expense, taxes and a fair return on investment for the utility. In some cases Cost of Service also includes cost of gas

COV – City of Vancouver

CP – Commercial Paper

CPCN – Certificate of Public Convenience and Necessity, a certificate is obtained from the BCUC under Section 45 of the *Utilities Commission Act* for the construction and, or operation of, a public utility plant or system, or an extension of either, that is required for public convenience and necessity

CPI – Consumer Price Index

CPR – Conservation Potential Review, a study completed to identify opportunities for energy savings across gas and electrical energy delivery infrastructures and improvements to overall energy utilization efficiency

CSA – Canadian Standards Association

CST – California Standard Tests

CTS – Coastal Transmission System

DHW – Domestic Hot Water

DSM – Demand-Side Management, defined as “any utility activity that modifies or influences the way in which customers utilize energy services”. From FEI’s perspective, the primary objectives of DSM are to increase the overall economic efficiency of the energy services it provides to customers and maintain the competitive position of natural gas relative to other energy sources

DTQ – Daily Take Quantities

EARSL – Expected Average Remaining Service Life

ECAP – Energy Conservation Assistance Program

ECM – Efficiency Carry-Over Mechanism

EEC – Energy Efficiency and Conservation

EEC Application – 2008 Energy Efficiency and Conservation Programs Application

EEC Decision – BCUC Order G-36-09

EEC NGV Incentives Review Decision – BCUC Order G-145-11

EEC Plan – FEU 2014-2018 Energy Efficiency and Conservation Plan

EF – Efficiency Factor

EH&S – Environment, Health & Safety

EIT – Engineer in Training

EM&V – Evaluation, Measurement and Verification

ESK – Energy Saving Kit

ESM – Earnings Sharing Mechanism

FAES – FortisBC Alternative Energy Services Inc., an affiliated regulated business which undertakes TES projects

FBC – FortisBC Inc. (electric)

FEI – FortisBC Energy Inc. (formerly Terasen Gas Inc.)

FEVI – FortisBC Energy (Vancouver Island) Inc. (formerly Terasen Gas (Vancouver Island) Inc.)

FEW – FortisBC Energy (Whistler) Inc. (formerly Terasen Gas (Whistler) Inc.)

FERC – Federal Energy Regulatory Commission

Fort Nelson – FortisBC Energy Inc. – Fort Nelson Service Area (formerly Terasen Gas Inc. – Fort Nelson Service Area)

FEU – FortisBC Energy Utilities (comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. (formerly Terasen Gas Utilities)

FHI – FortisBC Holdings Inc. (formerly Terasen Inc.)

FortisBC – FortisBC Utilities (consisting of the FEU and FBC)

Fraser Basin – Fraser Basin Council

Free Rider Rate – Percent who would have implemented an energy efficiency measure even without the program

GAAP – Generally Accepted Accounting Principles

GCOC – Generic Cost of Capital proceeding

GDP – Gross Domestic Product

GDPIPI FDD - Gross Domestic Product Implicit Price Index times Final Domestic Demand

GGRR – Greenhouse Gas Reduction (Clean Energy) Regulation

GHG – Greenhouse Gas

GJ or Gigajoule – A measure of energy equivalent to one billion joules. One joule of energy is equivalent to the heat needed to raise the temperature of one gram (g) of water by one degree Celsius (ºC) at standard pressure (101.325 kPa) and standard temperature (15ºC)

GSA – Geo-Spatial Analysis, which is a custom Microsoft Access Database application, developed by General Electric. The GSA software is capable of extracting data from FEI's Geographical Information System in real-time, as well as data from other enterprise systems and records

GST – Goods and Services Tax

GWh – Gigawatt-hours

HDD – Heating Degree Day, which is a measurement designed to reflect the demand for energy needed to heat a home or business, and derived from measurements of outside air temperature

HPBAC – Hearth, Patio & Barbecue Association of Canada

HR – Human Resources

HST – Harmonized Sales Tax

HVAC – Heating, Ventilation, and Air Conditioning

IAS – Internal Audit Services

IASB – International Accounting Standards Board

IBEW – International Brotherhood of Electrical Workers

ICE Fund – Innovative Clean Energy Fund

ICE Levy – Innovative Clean Energy levy of 0.4% on purchases of energy including electricity and natural gas was eliminated effective April 1, 2013

IFRS – International Financial Reporting Standards

ILI – In-Line Inspection

IMP – Integrity Management Program

IP – Intermediate Pressure

IPMVP – International Performance Measurement and Verification Protocol

IPPs – Independent Power Producers

IR – Incentive Regulation (in the context of inflation factors)

IRs – Information Requests or interrogatories (in the context of the regulatory process)

IRM – Integrated Resource Management

I-Factor – Inflation Factor

ISO – International Standardization Organization

IT – Information Technology; or in the context of rate classes, means Interruptible Service Rate Class

ITS – Interior Transmission System

IVR – Interactive Voice Response

KORP – Kingsvale-Oliver Reinforcement Project

LDCs – Local Distribution Companies

LILO – Lease In-Lease Out

LiveSmart BC – LiveSmart BC Efficiency Incentive Program

LNG – Liquefied natural gas, natural gas stored at a low temperature turns to liquid form. Approximately 600 times as much natural gas can be stored in its liquid state than in its typical gaseous state; however, specialized storage facilities must be constructed

LTRP – Long Term Resource Plan

LTSP – Long Term Sustainment Plan, which includes enhancements to the Companies' asset management and system integrity processes

M&E – Management and Exempt employees; or in the context of EEC means Measurement and Evaluation

MBH – 1 MBH = 1000 BTU/hr (BTU = British Thermal Unit = the heat energy required to raise 1 pound of water by 1 degree Fahrenheit)

MCRA – Midstream Cost Reconciliation Account

MEM – Formerly Ministry of Energy and Mines (now Ministry of Energy, Mines and Natural Gas)

MEMNG – Ministry of Energy, Mines and Natural Gas

MFD – Multi Family Dwelling

MFT – Motor Fuel Tax of 1.9 cents per 810.32 litres of natural gas used in compressors

MOU – Memorandum of Understanding

MTRC – Modified Total Resource Cost Test

MURB – Multi-Unit Residential Buildings

MX Test – Main Extension economic test analyzes cost estimates for installing a gas main, projections in numbers of customers attached as well as forecast customer gas usage

MW – Megawatt

NEB – National Energy Board; or in the context of EEC means Non-Energy Benefits

NGT – Natural Gas Transportation, which refers to the NGV initiatives within the Innovative Technologies Program Area

NGV – Natural Gas for Vehicles

NPV – Net Present Value

NRCan – Natural Resources Canada

NSA – Negotiated Settlement Agreement

NSP – Negotiated Settlement Process

NTG – Net-to-Gross Ratio

NWN – Northwest Natural Gas Company

OBF – On-Bill Financing

OEB – Ontario Energy Board

OH&M – Overhead and Marketing

OPEB – Other Post-Employment Benefits

O&M – Operating and Maintenance

Opex – O&M Expenditures

OSC – Ontario Securities Commission

PACA – Participant Assistance/Cost Award

PBR – Performance Based Ratemaking

PC – Personal Computer

PCT – Pacific Carbon Trust; or in the context of EEC means Participant Cost Test

PPM – Project Portfolio Management

PST – Provincial Sales Tax in British Columbia

PV – Present Value

Rate Volatility – The magnitude and frequency of natural gas rate fluctuations

REC – Residential Energy Credit

REnEW – Residential Energy and Efficiency Works

REUS – Residential End Use Survey

RIM or Rate Impact Measure – A test that measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program

RLCFRR – Renewable and Low Carbon Fuel Requirements Regulation

ROE – Return on Equity

RRA – Revenue Requirements Application

RSAM – Revenue Stabilization Adjustment Mechanism

SAE – Statistically Adjusted Engineering

SAP – FEI's main integrated IT system

Scorecard – A strategic performance management tool containing business performance metrics which include a mixture of financial and non-financial measures each compared to a 'target' value

SCP – Southern Crossing Pipeline

SEC – United States Securities and Exchange Commission

SFD – Single Family Dwellings

SLCA – Service Line Cost Allowance

SQI – Service Quality Indicator

SST – Social Services Tax

TC – Total Capital

TECA – Thermal Energy Comfort Association

TES or Thermal Energy Services – All TES projects are undertaken by an affiliated regulated business, FortisBC Alternative Energy Services Inc.

TESDA – Thermal Energy Services Deferral Account

TFP – Total Factor Productivity. Under the total expenditure approach, Opex and Capex are summed up and regulated under on efficiency factor

TRC – Total Resource Cost test, which that measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs

Totex – Total Expenditure

TPP – Transfer Pricing Policy. See also COC/TPP

TRC – Total Resource Cost Test

UAF – Unaccounted-for gas, which refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use

UBC – University of British Columbia

UCA – Utilities Commission Act

UPC – Use per Customer

USoA – BCUC Uniform System of Accounts

Utility Cost Test – Measures the net costs of demand-side management programs as a resource option based on the costs incurred by the utility (including incentive costs) and exclude the net costs incurred by the participant

X-Factor – Efficiency factor, or productivity offset

Z-Factors – Exogenous factors; non-controllable, unforeseeable costs that flow-through to rates

ZEEA – Zero-Emission Energy Supply Alternative

Appendix B1

CORPORATE HISTORY

CORPORATE HISTORY

FortisBC Energy Inc. (FEI)[1] is a company incorporated under the laws of the Province of British Columbia (BC or Province) with almost 60 years of history in the natural gas business offering a reliable supply of natural gas, delivered safely and efficiently at a reasonable cost.

The Company began distribution and transmission of natural gas in BC in the 1950s. In 1952, Inland Natural Gas Co. Ltd. (Inland) was incorporated to distribute natural gas throughout the BC interior. In the 1950s, Inland purchased several subsidiaries, including St. John Oil and Gas, Peace River Transmission, Canadian Northern Oil and Gas, and Grand Prairie Transmission. In 1977, Inland purchased Columbia Natural Gas in the East Kootenays, which positioned Inland as the major distributor of natural gas for most of the BC Interior. In 1985 Inland acquired Fort Nelson Gas Ltd., the owner of the gas distribution system in and around Fort Nelson, from Colonial Oil and Gas Limited and in 1987, Inland purchased Squamish Gas Co. Ltd. from Superior Propane Ltd. In 1988, through a holding company named BC Gas Inc., Inland purchased the Lower Mainland gas division of British Columbia Hydro and Power Authority. In 1989, Inland was amalgamated with BC Gas Inc., Columbia Natural Gas Limited, and Fort Nelson Gas Ltd. under the name BC Gas Inc. and become the fourth largest gas distribution utility in Canada.

In 1990, BC Gas commenced construction, operation and maintenance of a piped propane distribution system to serve residential and commercial customers in Revelstoke. Propane is transported to Revelstoke by railcar and tanker-truck and off-loaded at an above-ground site. The propane is vapourized at the above-ground site and then distributed through underground gas lines, today serving approximately 1,600 residential and commercial customers.

In 1993 restructuring caused BC Gas Inc. to change its name to BC Gas Utility Ltd. and a holding company that held all the shares of BC Gas Utility Ltd. was named BC Gas Inc. A subsidiary of BC Gas Utility Ltd. was Squamish Gas Co. Ltd. In 2003, BC Gas Inc. changed the name of each of its corporate entities, with BC Gas Inc. becoming Terasen Inc. (the holding company of the natural gas utilities) and BC Gas Utility Ltd. becoming Terasen Gas Inc.

In 2005, Terasen Inc. was acquired by Kinder Morgan Inc., a US energy storage and transportation company operating on behalf of Kinder Morgan Energy Partners, L.P. In 2007, Terasen Gas Inc. and Terasen Gas (Squamish) Inc. were amalgamated to operate as one company under the name, Terasen Gas Inc.

In 2007, Fortis Inc. acquired Terasen Inc. from Kinder Morgan Inc., and on March 1, 2011, the Terasen group of companies was renamed, and Terasen Inc. became FortisBC Holdings Inc., and Terasen Gas Inc. became FortisBC Energy Inc.

Today, FEI, a wholly owned subsidiary of FortisBC Holdings Inc., provides natural gas transmission and distribution services to approximately 835,000 residential, commercial, and industrial customers in approximately 115 communities on the mainland including the Inland, Columbia, Fort Nelson, and Lower Mainland service areas. In this Application, the term “FEI” refers to all service territories except Fort Nelson, which operates as a separate utility and has its rates set under separate applications.

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[1] Formerly Terasen Gas Inc.

Appendix B2

KEY OPERATING FACTS

Appendix B2 **Key Operating Facts**

FEI
Annual Report Statistics
2005-2012

	2005	2006	2007	2008	2009	2010	2011	2012
Customers:								
12 Month Average Residential Customers	712,427	722,865	735,263	743,756	749,999	756,051	762,050	755,922
12 Month Average Commercial Customers	76,880	77,511	78,810	79,538	80,373	80,589	80,819	76,533
12 Month Average Industrial Customers	428	383	334	306	294	268	258	247
12 Month Average Transportation Customers	1,819	1,947	1,984	2,066	2,058	2,084	2,135	2,169
12 Month Average NGV Customers	39	37	36	30	27	25	20	17
Total Average Customers	**791,593**	**802,743**	**816,427**	**825,696**	**832,751**	**839,017**	**845,282**	**834,888**
Total Year End Customers	799,365	809,559	822,598	831,845	836,918	843,846	849,227	839,064
Gas Deliveries (Normalized Actual):								
Residential Gas Delivery (TJ)	68,962	68,240	70,638	68,841	69,999	70,041	68,933	69,753
Commercial Gas Delivery (TJ)	38,422	37,767	39,581	39,667	40,716	40,013	40,761	41,063
Industrial Gas Delivery (TJ)	4,547	4,072	3,692	3,408	3,168	2,660	2,870	2,743
Transportation Gas Delivery (TJ)	99,923	98,708	100,791	98,081	86,856	88,336	85,864	86,767
NGV Gas Delivery (TJ)	186	135	117	94	83	61	69	62
Total Gas Deliveries	**212,040**	**208,922**	**214,819**	**210,091**	**200,822**	**201,111**	**198,497**	**200,388**
Cost of Gas (Normalized)								
Average Cost of Gas Sold ($/GJ)	$ 8.45	$ 9.13	$ 8.45	$ 8.91	$ 7.18	$ 6.76	$ 5.68	$ 4.75
O&M:								
Approved CPI (BC)	2.0%	2.2%	2.0%	2.1%	2.1%	1.9%	2.0%	2.0%
Gross O&M Decision (adj for Pension/Insurance Variance from 2005-2009)	$ 190,586	$ 196,919	$ 199,462	$ 200,052	$ 203,994	$ 207,258	$ 215,492	$ 227,864
Gross O&M Actual	171,602	180,026	179,808	186,479	192,729	207,313	214,459	220,619
Capitalization Allowed	-26,335	-27,243	-27,535	-27,684	-28,241	-29,019	-30,169	-31,901
Vehicle Lease	-1,911	-1,872	-2,008	-1,988	-1,804	-	-	-
Fort Nelson Allocation	-646	-688	-701	-599	-658	-680	-739	-793
Total Net O&M	**$ 142,710**	**$ 150,223**	**$ 149,564**	**$ 156,208**	**$ 162,026**	**$ 177,614**	**$ 183,551**	**$ 187,925**
Headcount								
Average Full Time Equivalent (FTE)	1,089	1,059	1,084	1,124	1,165	1,241	1,427	1,571
Distribution Fast Facts:								
Outages caused by Third Party	1,457	1,434	1,545	1,574	1,322	1,253	1,125	947
Gas Odour Calls	20,443	23,497	22,792	20,335	18,620	18,710	18,350	15,448
CO Calls	1,418	1,224	1,573	1,583	1,350	1,660	1,660	1,567
Fire Calls	733	882	996	973	780	690	750	790
Meter Recalls	45,448	28,457	32,175	33,275	45,125	61,560	60,970	64,801
Locates	1,837	1,739	2,378	3,153	2,900	2,550	2,460	1,990
Calls to BC 1 Call	46,500	46,500	58,000	41,000	54,642	59,050	63,445	67,726
Lock Offs (Excludes Contractor)	11,996	10,054	11,224	12,251	12,029	12,115	10,720	7,322
Unlocks	33,211	29,804	33,824	32,961	31,100	29,120	26,750	15,548
Service Lines (Risers)	713,700	713,700	743,928	735,891	753,321	761,677	765,164	768,467
# of Main Valves	9,438	9,438	9,425	9,024	8,808	8,951	8,954	8,954
# of Service Valves	16,994	16,994	16,960	16,735	17,485	17,681	17,612	17,881
Regulator Stations	416	416	416	390	389	413	380	392
Line Heaters	200	200	200	245	228	233	241	195
Pipeline Stats:								
Total TP Pipe (KM's)	2,415	2,415	2,418	2,418	2,319	2,324	2,569	2,332
Total IP (KM's)	350	350	516	511	502	504	505	503
Total DP Service Pipe (KM's)	17,205	17,455	17,655	17,872	18,463	17,196	21,624	20,329
Total DP Main Pipe (KM's)	19,018	19,377	19,730	20,123	18,766	19,449	19,462	19,041
Total LP Pipe (KM's)	100	100	58	24	0.5	-	-	-
Total Pipeline	**39,088**	**39,697**	**40,377**	**40,948**	**40,051**	**39,473**	**44,160**	**42,205**
System Outages:								
Outages	2,291	2,414	2,935	2,638	1,975	2,333	1,146	969
Customers Affected	3,981	2,691	3,631	2,772	2,674	3,613	1,971	2,490
System Leaks:								
Transmission Pipeline Leaks	3	1	1	2	-	-	-	-
Distribution Pipeline Leaks	120	71	87	57	60	140	166	169
Emergency Response Time (minutes)	21:42	21:24	20:36	20:42	22:41	22:30	23:24	23:48
Service Quality Indicators:								
Emergency Calls Answered in 30 seconds	99.0%	98.7%	98.4%	98.3%	98.3%	99.2%	98.3%	96.1%
% of Transportation Customer Bills Accurate	99.9%	99.9%	99.5%	94.3%	96.0%	99.9%	100.0%	99.1%
Customer Satisfaction	77.2%	77.9%	79.3%	79.7%	80.1%	80.0%	79.3%	78.9%
Customer Complaints to BCUC	100	145	130	90	58	26	3	3
Miscellaneous:								
Rate Base, Mid-Year	$ 2,408,090	$ 2,442,636	$ 2,425,545	$ 2,471,877	$ 2,460,772	$ 2,525,315	$ 2,563,141	$ 2,692,583
Allowed Return	9.03%	8.80%	8.37%	8.62%	8.99%	9.50%	9.50%	9.50%

Appendix B3

MUNICIPALITIES SERVED

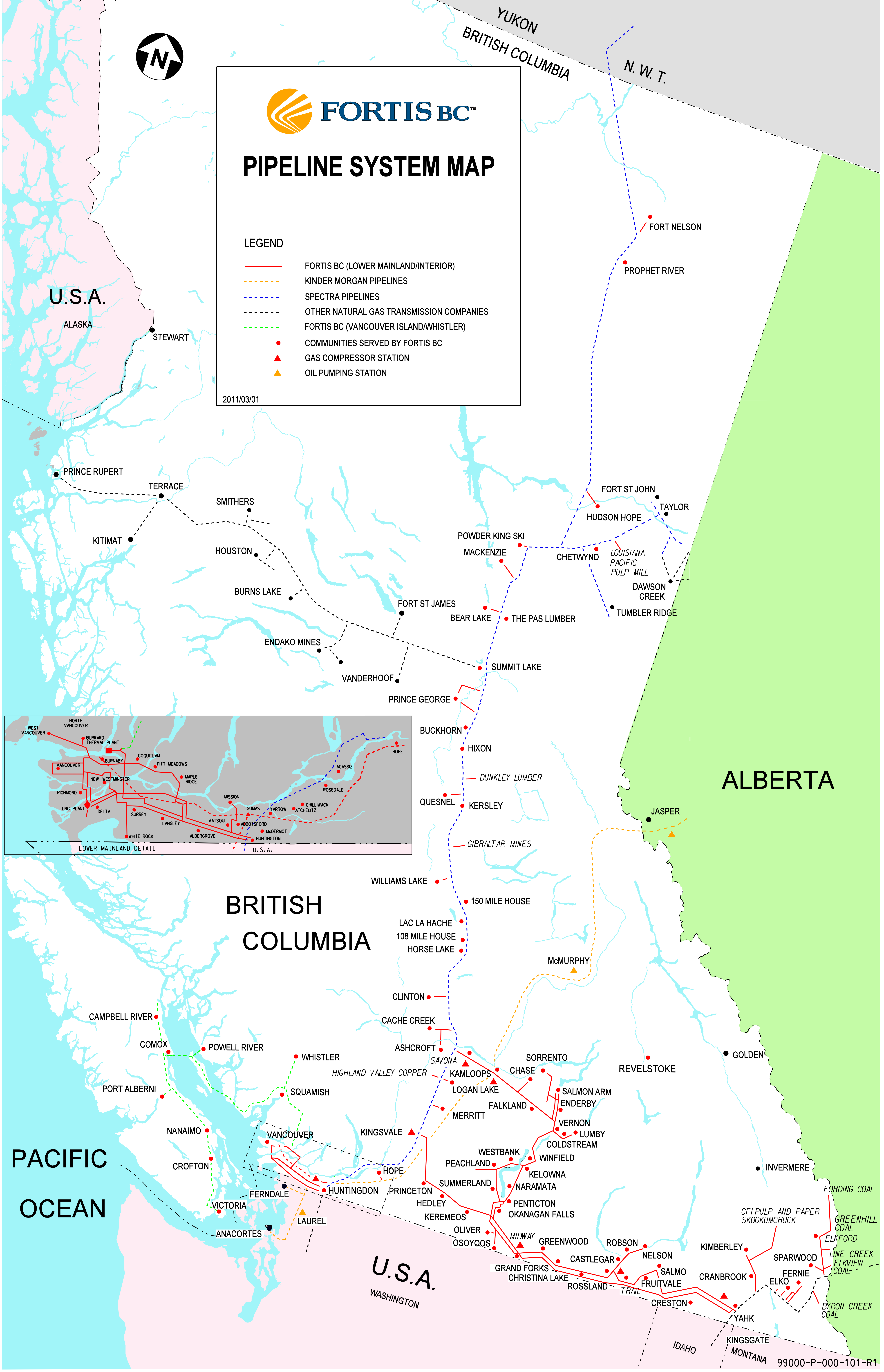
FEI MUNICIPALITIES SERVED:

100 Mile House
150 Mile House
70 Mile House
Abbotsford
Agassiz
Aldergrove
Anmore
Armstrong
Arrow Creek
Ashcroft
Belcarra
Blind Bay
Brackendale
Burnaby
Cache Creek
Calgary
Castlegar
Cawston
Chase
Chetwynd
Chilliwack
Christina Lake
Clinton
Coldstream
Coquitlam
Cranbrook
Creston
Cultus Lake
Delta
Elkford
Enderby
Falkland
Fernie
Fort Nelson
Fruitvale
Grand Forks
Greenwood
Grindrod
Harrison Hot Springs
Hedley
Heffley Creek
Hixon
Hope
Hudson's Hope
Kaleden
Kamloops
Kelowna
Kent
Keremeos
Kersley
Kimberley
Kitchener
Lac La Hache
Lake Country
Langley
Lindell Beach
Logan Lake
Lone Butte
Lower Nicola
Lumby
Mackenzie
Maple Ridge
Merritt
Midway
Mission
Mississauga
Montrose
Naramata
Nelson
New Westminster
North Vancouver
Okanagan Falls
Oliver
Osoyoos
Oyama
Peachland
Penticton
Pitt Meadows
Port Coquitlam
Port Moody
Prince George
Princeton
Pritchard
Quesnel
Revelstoke
Richmond
Robson
Rock Creek
Rosedale
Rossland
Salmo
Salmon Arm
Savona
Sorrento
South Slocan
Spallumcheen
Sparwood
Squamish
Summerland
Surrey
Tappen
Tobiano
Trail
Tsawwassen
Vancouver
Vernon
Virtual
Warfield
West Kelowna
West Vancouver
White Rock
Williams Lake
Winfield
Wynndel

Appendix B4

PIPELINE SYSTEM MAP

B4 - FEI Pipeline System Map



Appendix C1

COMPLIANCE WITH PAST DIRECTIVES TABLE OF CONCORDANCE

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
G-44-12 – FEU 2012-2013 REVENUE REQUIREMENTS AND RATES DECISION (DATED APRIL 12, 2012)					
1.	26	No. 1 Appendix A, p.1	***Residential Customer Usage Rates and Demand Forecast:*** The Commission Panel agrees with the BCOAPO that it would be of value for the FEU to file a financial analysis of the impact of variances in the forecast of customer additions on all rate classes when they file their next RRA and the FEU are directed to do so.	Analysis provided	Section C1.4 and Appendix E5
2.	40	No. 7 Appendix A, p. 2	***O&M Productivity Improvement:*** The Commission Panel further directs the FEU to file a Productivity Improvement Plan with their next revenue requirements application. The Productivity Improvement Plan may take the form of a proposal for PBR which places emphasis on both-short term activities as well as long term, sustainable improvements.	PBR Proposal filed	Section B
3.	52-53	No. 13 Appendix A, p. 3	***Customer Service:*** The Panel expects the FEU to address the matter of leveraging the Customer Care function to maximize productivity opportunities in the next revenue requirements application. This should provide ample time for stabilization of the system and a better understanding of potential opportunities.	Customer Care and productivity discussion provided	Sections A3.3 and C3.5
4.					
5.	67	No. 22 Appendix A, p. 4	***Environment, Health and Safety:*** FEI is directed for future revenue requirements to determine potential alternatives for the delivery of this [environmental training] program and potentially integrate it with other training initiatives	Integrated with other training activities	Section C3.12
6.	71	No. 25 Appendix A, p. 4	***Corporate and Shared Services:*** The Commission Panel directs the FEU to update both the Corporate and Shared Service Agreements for inclusion in their next revenue requirements application. Further, the Commission Panel directs the FEU to break activities of the FEU entities into two, distinct parts: • Those of traditional gas operations, and • Those of TES offerings so that costs attributable to each entity of the FEU can be clearly broken down by their TES component.	Corporate and Shared Service Agreements updated. Discussion of TES provided.	Section D3.6

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
7.	78	No .29 Appendix A, p. 4	***Capitalized Overhead:*** The Commission Panel directs the FEU to update their capitalized overhead methodology using relevant accounting standards in the next test period. The Commission Panel further directs the FEU to obtain a report on this methodology from a qualified independent third party for inclusion in their next revenue requirements application.	Capitalized overhead methodology updated and KPMG report filed	Section D3.7 and Appendix F3
8.	81	not identified in Appendix A list of directives	***Depreciation Rates:*** The FEU are directed to report the annual additions to this deferral account by asset class in a report to be included with the Utilities' Annual Regulatory Report. The report is to include a breakdown of each addition by depreciation amount and tax effect subtotalling to an amount for each deferral. The total of deferrals in this report shall agree to annual deferrals made to the account. For each asset resulting in a deferral, the asset shall be further broken down by asset class components, indicating the deferred depreciation and deferred tax impact of each component (by asset class). The tax amounts shall include a notation of the CCA class to which they relate as well as the CCA rate for that class.	Provided in BCUC Annual Report	N/A

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
9.	85	No. 34 Appendix A, p. 6	***Negative Salvage Value:*** The Commission Panel directs the FEU to continue forecasting salvage costs in each test period and to include this estimate in future revenue requirements applications. Actual results of the past test period should be included in these applications. In addition, the FEU are directed to provide annual reports to the Commission, of total accumulations, by asset class, of the following: i) total salvage provision for the period, ii) total salvage expenditures, iii) a description of the total value of the asset rate base retired by asset class, iv) descriptions of the most common methods of retirement used during the period, v) the annual and cumulative to date (starting in 2012) actual cost to salvage assets, as a percentage of the actual rate base value of the assets retired, and a comparison of how that rate compares to the rate recommended in the prior depreciation study, vi) a general description of any major trends or retirements that have occurred in the year (i.e. a specific type of pipe or type of meter that required a significant retirement), and vii) an update of trends, any alternative retirement methodologies not being used by the FEU and the future outlook of retirement procedures for each asset class including a description of how any changes in methodologies or available technologies could affect retirement costs.	i), ii), iii) and v) provided in BCUC Annual Report; iv), vi) and vii) discussed in this Application	Section D3.4
10.	87	No. 35 Appendix A, p. 6	***Asset Losses:*** The Commission Panel directs the Utilities in the future to fully and transparently disclose the nature and amount of all assets or amounts included in their plant in service account that are being depreciated into rates but are not in use, or are not expected to be in use in the test periods, whether due to retirement or for other reasons.	Asset loss items provided	Section D3.5

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
11.	88	No. 36 Appendix A, p. 7	***Asset Losses:*** While losses of this nature may be a part of group asset depreciation, the Commission Panel directs the Utility to disclose specific information in future filings with the Commission. The disclosures should include the following: 1) Future revenue requirements applications shall include details of actual asset losses, by asset class, for the past 10 years. They shall also include a forecast of losses, by asset class, for the remaining asset class, unadjusted for capital additions expected to occur outside the test period. As asset losses are expected under group depreciation, the Commission Panel believes that a projection of these losses should be readily determinable and should directly tie into depreciation forecasting methodology. When the Utilities obtain future depreciation studies, the study expert should incorporate this loss-forecast schedule into the study and should explain how the amounts have been taken into account in the asset class depreciation rates. 2) Future revenue requirements applications shall detail efforts made to minimize early asset retirements and to demonstrate how the utility intends to maximize the value of assets in use. As group depreciation methodology determines assets' useful lives on an average basis, the Commission Panel expects that at least some of the assets should be expected to last longer than their estimated useful lives. The Utilities shall describe the steps taken to determine which assets these might be and how the Utilities intend to identify, maintain and repair such assets. Furthermore, this process should incorporate capital asset maintenance plans to demonstrate how the value of assets in use is to be maximized such that assets are not just replaced, on a blanket basis, at the end of the assets' average service life.	Asset loss items provided	Section D3.5
12.	93	No. 38 Appendix A, p. 7	***Long-Term Sustainment Plan (LTSP):*** The Commission Panel directs the FEU to provide a status update on the LTSP, systems developed and the nature of assets replaced in their next revenue requirements application.	Status update provided	Section C4.4.3 and Appendix C3
13.	102	No. 42 Appendix A, p. 8	***IT Capital – Customer Service:*** In addition, the Commission Panel reminds the Utilities that, when planning for IT capital expenditures, the FEU should take into consideration their relatively flat customer base. In the view of the Panel, an increase in IT capital expenditures in the future should be remedial in nature, and demonstrate a clear ability to correct inadequate operational matters or reduce other operating costs from the status quo. Therefore, the Commission Panel directs the FEU in future RRAs to clearly identify either a shortcoming in current customer service levels or provide a fulsome budgeted O&M cost reduction, including the year of realization of expected savings, resulting from each significant IT Capital project in order to justify spending requests.	No increase in IT capital expenditures forecast; link to benefits discussed	Appendix C4

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
14.	115-116	No. 52 Appendix A, p. 9	***Non-Controllable Deferral Account Items – Customer Service Variance Account:*** The Commission Panel approves the creation of the Customer Service Variance Account as applied for with the amortization period to be determined in the next revenue requirements application of the FEU.	Amortization period of 5 years proposed	Section D4.2.5
15.					
16.	127	not identified in Appendix A list of directives	***Performance Metrics:*** The Commission Panel is concerned that productivity is not being optimized. Further, the Panel agrees with the CEC that the balanced scorecard, while tracking O&M per customer, does not adequately measure productivity. The Commission Panel directs that for the next revenue requirements application, the FEU bring forward a benchmarking study that would assess their balanced scorecard against mechanisms used in other peer group companies and jurisdictions. Such an assessment should examine, among other things, the appropriate measurements for productivity and describe what a fulsome set of productivity measurements would entail. Additionally, the Commission Panel believes it would be useful for this study to examine how other members of the FEU's peer group link the use of their performance metrics with the assessment of corporate and individual performance.	Benchmarking study conducted and provided Productivity measurements discussed	Appendix C2 for Benchmarking Study; Section A2.3 for Productivity Measures
17.	140	No. 62 Appendix A, p. 11	***Overhead and Sales and Marketing Cost Allocation:*** For future revenue requirements applications, the FEU are directed to propose criteria which can be used to provide a better assessment of an appropriate overhead and sales and marketing cost allocation.	Deferred to future Code of Conduct/TPP an TESDA review processes	Section D3.6
18.	142	No. 63 Appendix A, p. 11	***Uniform System of Accounts and Budgeting:*** The Commission Panel directs the FEU to begin investigating the cost of fully converting to the USoA and to work with Commission staff to develop a plan that will allow the FEU to fully adopt the USoA prior to filing their next RRA with the Commission. A proposed plan for conversion within the timelines presented should be discussed with Commission staff and filed with the Commission no more that 180 days from the date of this Decision. The filing should identify any cost deferral account mechanism needed to facilitate the changeover.	Subsequent Commission letter agreed to continue with current BCUC Activity and Resource Views for this Application	Section C3.1.2
19.	151	No. 66 Appendix A, p. 12	***EEC – Deferral Account:*** The Panel is not persuaded that a ten-year amortization period is necessarily appropriate but the issue was not canvassed thoroughly enough in this Proceeding to warrant a change. To assist in understanding this issue, the FEU are directed to provide a report detailing the rate impact of a number of amortization scenarios which will be helpful in determining a long term solution.	Amortization scenarios provided	Appendix I

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
20.	171	No. 72 Appendix A, p. 13	***EEC – Inclusion of Spillover Effects:*** The Commission Panel agrees that the FEU's current practice of including free riders but not spillover adjusts DSM program savings downwards only and results in a one-sided adjustment to energy savings. However, the Panel believes it would not be appropriate to make a determination on the inclusion of spillover without a full assessment of the merits of including spillover based on a specific set of facts before the Commission. Accordingly, the Commission Panel makes no determination on the inclusion of spillover in this RRA. The FEU may readdress this issue in future applications.	FEU has proposed spillover within this Application.	Appendix I
21.	183	No. 80 Appendix A, p. 14	***EEC – Incentives Provided for AES/TES Projects:*** The Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application. That Panel will have a benefit of the Panel's decision in the AES Inquiry.	Disposition deferred until after the TESDA disposition is finalized.	Appendix F5
G-101-12 – FEI KINGSVALE-OLIVER REINFORCEMENT PROJECT (KORP) STAGE 2A PROJECT DEVELOPMENT COSTS AND ACCOUNTING TREATMENT DECISION (DATED JULY 23, 2012)					
22.	3, 8, 9	No. 3	***FEI KORP Stage 2a Deferral Account:*** FEI is directed to establish a new non-rate base deferral account for recording of Stage 2a feasibility expenses with treatment of interest rate and deferral period to be determined at the next Revenue Requirement.	Disposition deferred due to extension to time required to complete Stage 2a.	Appendix F5
G-201-12 – FEI INQUIRY INTO THE OFFERING OF PRODUCTS AND SERVICES IN ALTERNATIVE ENERGY SOLUTIONS AND OTHER NEW INITIATIVES REPORT (DATED DECEMBER 27, 2012)					
23.	53	CNG Activities No. 2, Appendix H, p. 2	***CNG Activities:*** CNG activities undertaken as Prescribed Undertakings, are to be structured as a Separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit.	Done	Appendix H
24.	62	LNG Activities No. 2, Appendix H, p. 2	***LNG Activities:*** LNG activities undertaken as Prescribed Undertakings are to be maintained as a Separate Class of Service with the costs recoverable from the traditional natural gas ratepayer.	Done	Appendix H

No.	Decision / Order Page No.	Directive No. or Reference	Description / Details	Status, Action Taken, Relevant Filing Dates and Comments	Section in this Application
25.	87	Other Findings No.	***Other Findings and Determinations –DSM and Incentive Funding:*** The FEU are directed to bring forward a proposal for mechanisms for approval and administration of DSM and other incentive funds by a neutral third party where there is a potential for FEU to benefit, either directly or indirectly, from that funding.	Proposal included in Approvals Sought	Appendix I
G-56-13 – FEI RATE TREATMENT OF EXPENDITURES UNDER THE GGRR (PHASE 1 AND 2) DECISION (DATED APRIL 11, 2013)					
26.	62	not identified in Appendix A list of directives	***Deferral Accounts*** The Commission Panel finds that the proposed method of accounting for the GGRR grants and program costs through the use of the proposed deferral accounts is a reasonable mechanism to capture costs until the next revenue requirement where all costs could be forecast and included in the cost of service through rate base deferral accounts for the next test period.	GGRR grants and program costs have been forecast in the NGT Incentives deferral account	Appendix F4

Appendix C2

BALANCED SCORECARD BENCHMARKING

Benchmarking Study of Scorecard Design and Application – Canadian Natural Gas Distribution Utilities

June 2013

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1. RESEARCH BACKGROUND AND OBJECTIVES

On April 12, 2012, the British Columbia Utilities Commission (BCUC or the Commission) issued its Decision and accompanying Order G-44-12 (the Decision) on the FortisBC Energy Utilities'[1] (the FEU) 2012-2013 Revenue Requirements and Natural Gas Rates Application (2012-2013 RRA)

Page 127 of the Decision (Section 6.9) directs that, as part of its next revenue requirement application (RRA), "*the FEU bring forward a benchmarking study that would assess their scorecard against mechanisms used in other peer group companies and jurisdictions*". The Commission also suggests that "*it would be useful to examine how other members of the FEU's peer group link the use of their performance metrics with the assessment of corporate and individual performance.*"

Pursuant to the BCUC's directions, a benchmarking study of scorecard design and application for Canadian natural gas distribution utilities was completed with the following objectives:

- To assess how the FEU's scorecard categories and performance metrics compare to those of other Canadian natural gas distribution utilities.
- To examine how other Canadian natural gas distribution utilities link their scorecard performance metrics with their assessment of corporate and individual performance.

A summary report of this benchmarking study is presented in the following sections.

2. RESEARCH METHODOLOGY

A scorecard benchmarking study team, with representation from the regulatory, finance and human resources departments of the FEU, was established to discuss the research methodology and framework of the study.

The research team decided to use a survey approach to gather the necessary information. The survey target group was focused on Canadian natural gas distribution utilities to reflect FEU's "peer group" companies.

In total, six Canadian natural gas distribution utilities[2] were surveyed. The six companies are located in various jurisdictions, with a representative for each of the major gas consuming provinces.

The survey questions asked of each company are listed below:

[1] Consisting of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.
[2] ATCO Gas, Enbridge Gas, Gaz Metro, Manitoba Hydro(gas), Sask Energy, Union Gas

- Does your company use a balanced scorecard mechanism to drive performance across the organization?
- If the answer is yes, please provide information about the structure of the scorecard including the different components and measures, the logic behind the choice of the different components and measures and how targets are set for the different measures on the scorecard.
- How are the performance metrics linked to the assessment of corporate and individual performance?

The survey response rate was one hundred percent for the target representatives. The survey determined that in total, five of six selected companies have some form of balanced scorecard (BSC) mechanism and also link their scorecard results to their individual and/or corporate performance. Only one company surveyed did not currently apply a scorecard mechanism for its performance measurement.

In the following sections, a summary of survey responses provided by the companies is included. The summary is based on information as provided directly by the companies' representatives. Please note that due to confidentiality, company specific identifiers are not disclosed in the report's tables and descriptions. For presentation purposes, each company has been given a numerical identification without any relevant order or sequence.

3. THEORY AND FORMAT OF SCORECARDS IN SELECTED COMPANIES

The balanced scorecard was first introduced by Kaplan and Norton[3] (1992). The model translates an organization's mission and strategy into a comprehensive set of performance measures from a "balanced" perspective and is comprised of four major performance perspectives (Financial, customer, internal processes and innovation and learning). However, as emphasized by Kaplan and Norton themselves, "*balanced scorecard is not a template that can be applied to business in general or industry-wide*"[4] and that companies *"devise customized scorecards to fit their mission, strategy, technology, and culture".*

The survey responses indicate that the majority of selected companies use a balanced scorecard based on a customized version of the Kaplan and Norton model where financial, safety and customer are the three primary performance areas common to all surveyed companies. There are also some company-specific metrics designed to monitor performance consistent with the utilities' business plans. These metrics can be grouped into employee

[3] Kaplan, R.S. & Norton, D.P. (1992). "The Balanced Scorecard: Measures that Drive Performance", Harvard Business Review, (January-February): 71-79.
[4] Kaplan, R. S. & Norton D. P. (1993) "*Putting the Balanced Scorecard to Work*", Harvard Business Review (September-October).

performance and governance performance which includes regulatory and compliance assessments (including environmental compliance).

4. PERFORMANCE AREAS AND KPIs

As discussed in the previous section, companies' performance areas are categorized into five separate groups (financial, customer, safety, employee and governance). In the following sections, these performance areas and their respective key performance indicators are reviewed in more detail.

4.1 *FINANCIAL KEY PERFORMANCE INDICATORS*

The measure of success in this area can be evaluated by various KPIs such as return on investment, cost reduction, revenue growth, market share, earnings, etc. FEU's financial KPI is defined as the FEU financial performance against targeted net earnings. The survey results demonstrate that other companies also consider different forms of earnings as their financial KPI (Earnings Before Interest and Taxes (EBIT), (Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), etc.). Provided in Table C2-1 below is a summary of the companies' responses.

Table C2-1: Financial KPIs among selected companies

Company	Financial KPIs
FEU	Net Earnings
1	Cost Efficiencies (year-end cash balance, O&M costs per customer, …)
2	EBIT, Cost control
3	Net Income (weather normalized to provide a fair assessment of performance)
4	Debt/Equity ratio, ROE, income before unrealized market value adjustment, EBITDA,..
5	Earnings, internal rate of return, new sales

4.2 *CUSTOMER KEY PERFORMANCE INDICATORS*

The customer performance area is part of the original Kaplan and Norton balanced scorecard model. Customer satisfaction surveys are the most common type of measurement used by the responding companies. Some companies have only one general customer satisfaction survey, while others differentiate between new and existing customers. Customer satisfaction surveys for industrial clients are sometimes separated from commercial and residential customers. FEU's "customer survey score" is the company's KPI for customer satisfaction and measures customers' overall satisfaction with the company, accuracy of meter reading, energy conservation information, contact centre performance, and field operations. The table below summarizes the surveyed companies Customer KPI's.

Table C2-2: Customer KPIs among selected companies

Company	Customer KPIs
FEU	Customer survey score
1	Customer favorable impression survey, percent of complaints resolved in 30 days, customer service response to emergency calls, …
2	Customer satisfaction, brand reputation, creating a positive customer experience
3	Customer satisfaction, corporate brand
4	Total customer satisfaction, new clients satisfaction rate, industrial clients satisfaction survey
5	Customer satisfaction, community investment

4.3 *SAFETY KEY PERFORMANCE INDICATORS*

Safety is not a separate item in the initial Kaplan and Norton model; however due to the importance of safety and reliability in the utility industry, all of the surveyed distribution companies have incorporated a safety performance area in their scorecard design. Safety KPIs can be generally divided into employee safety and public safety. All of these KPIs can be compared to common industry standards. FEU uses the all injury frequency rate (AIFR) and recordable vehicle accidents as safety metrics and the number of public contacts with pipeline (measured as the number of line damages per 1,000 BC One Calls received), as its customer and safety related metric. Table C2-3 below summarizes the safety indicators that are used by the surveyed companies.

Table C2-3: Safety Key Performance Indicators Among Selected Companies

Company	Safety KPIs	
	Employee	Public
FEU	All injury frequency rate, recordable vehicle accidents	Public contact with pipelines (customer and safety related)
1	Preventable vehicle accidents frequency, worker competency checks, driver competency checks, …	Damaged lines per 1000 locates, inspections (% of planned inspections completed), …
2	Work-related accident rate, accident severity rate, injury frequency rate, …	Preventive maintenance programs
3	Employee safety index (safety inspections and trainings, quality assurance, injuries and accidents), technical training composite index	Public safety and reliability index (corrosion protection, third party damages, unplanned outages, emergency response, quality acceptance faults, …)
4	Reportable injury rate, preventable vehicle accidents frequency	Safety and reliability (system outages, percentage of planned maintenance completed), safety and integrity (percentage of capital spending against corporation's assets)
5	Personal and operational safety, promoting a zero work-related injury culture	Operational safety

4.4 EMPLOYEE KEY PERFORMANCE INDICATORS

Employee KPIs have a close link to human resources (HR) activities. Four surveyed companies have such KPIs reflected in their scorecards. The employee KPIs for the surveyed companies are presented in Table C2-4.

Table C2-4: Employee Key Performance Indicators Among Selected Companies

Company	Employee KPIs
FEU	Monitored at departmental level supported by HR.
1	Leadership effectiveness, succession readiness, workforce planning effectiveness
2	Employee engagement, workplace diversity
3	Turn-over, recruitment (filing vacant permanent positions), …
4	Employee engagement, building a culture of continuous improvement
5	Not applicable

The FEU do not incorporate employee KPI's in its scorecard. Instead, employee KPI's are monitored at a departmental level, supported by HR and vary by area depending on business need. Employee KPIs monitored at the departmental level include internally filled positions, absenteeism rates and turnover.

4.5 GOVERNANCE KEY PERFORMANCE INDICATORS

In a regulated environment, a utility's operation and strategy are dependent on its ability to obtain the necessary regulatory approvals and complying with numerous regulations and standards imposed on its activities. Recognizing the importance of regulatory impact, all of the surveyed companies' scorecards include some form of company-specific regulatory and compliance metrics (including environmental compliance). In this report these metrics are grouped into governance KPIs. At the FEU, the regulatory environment has a major impact on company's ability to achieve its business plans and influences its operational efficiency and therefore is a part of the company's scorecard. The governance KPIs are summarized in Table C2-5 below.

Table C2-5: Governance Key Performance Indicators Among Selected Companies

Company	Governance KPIs
FEU	Regulatory performance (subjective)
1	SOX compliance, IT security policy compliance, service quality compliance, etc.
2	Number of company caused GHG releases, proper notifications releases to government environmental agency
3	Reduction of GHGs, ISO 14001, policy compliance rate with regard to meter reading, urgent interventions, etc.
4	Regulatory certainty
5	Customer energy efficiency programs, internal energy efficiencies, % of regulatory targets achieved

5. SCORECARD LINKAGE TO CORPORATE / INDIVIDUAL PERFORMANCE

In the majority of companies surveyed, the scorecard results have some level of impact on corporate and/or individual performance evaluation. One of the respondents stated that "*one of the most effective ways to help improve efficiency of the company is to link its employees to a combination of financial and operational results through a balance scorecard method of performance measurement*". The corporate scorecard results are often used to determine employees' incentive compensation payments.

The FEU's scorecard is directly linked to individual and corporate performance through a short term incentive program. All employees are eligible depending on performance, with the payment amounts varying depending on role, responsibility and affiliation. Table C2-6 demonstrates the range of mechanisms that are used to link scorecard results with companies' corporate/individual performance evaluation.

Table C2-6: Scorecards Linkage to Corporate/Individual Performance Evaluation Among Surveyed Companies

Company	Link to compensation
FEU	Short term incentive payment is linked directly to the corporate scorecard. Payment amount varies on role responsibilities and affiliation as well as individual performance.
1	Non-union employees' variable pay is linked to the scorecard results.
2	Non-union employees' performance assessments have some linkage to the metrics in their areas (metrics are used to determine the level of bonus an employee may get, but are not the only determining factor), the extent of which is determined by the executive team.
3	Employee incentive payment is partly based on corporate scorecard. Some departments use department scorecard results as part of individual performance assessment too.
4	The metrics are linked to the assessment of corporate performance and in the case of the executive team, individual performance. The results of certain metrics in the scorecard are leveraged by the regulator and the shareholder to determine the level of short term incentive provided to the corporate executive team.
5	Performance metrics on the scorecard are assessed annually to determine corporate performance. The employees are evaluated individually and compensation is weighted based on the corporate results. Some of the indicators are used by the regulator to determine the result of the incentive mechanism.

6. SUMMARY OF FINDINGS

The study findings indicate that the FEU's scorecard is generally consistent with scorecards used by its peer group companies and incorporates comparable categories and performance metrics. Additionally, for the majority of companies surveyed, the scorecard results have some level of impact on corporate and/or individual performance, with scorecard results often used to determine employee's incentive compensation payments.

Appendix C3

LONG TERM SUSTAINMENT PLAN

1. LONG TERM SUSTAINMENT PLAN

1.1 LTSP OVERVIEW

The FEU (Gas) Asset Management group provides planning and management oversight of the installation, operation, and maintenance of the Company's distribution and transmission gas system assets which includes approximately 23,000 km of distribution mains, 3,900 km of transmission pipelines, over 500 stations and over 30,000 valves installed with a combined book value of approximately $3 billion and a replacement value of approximately $6.8 billion. These natural gas assets are located throughout the province of British Columbia where natural gas continues to be delivered safely and reliably to more than 945,000 customers in over 140 communities.

Asset management at the FEU and its predecessor companies has been practiced in one form or another since the first piece of pipe was installed. However, in the early days when infrastructure was near the beginning of its service life, the processes in place and the general understanding of failure modes or causes were rudimentary. There was little history to draw from as well as limited experience with asset failures. This together with the fact that control and management of the assets was local and data collection was manual made it very difficult to develop an in-depth understanding of how to ensure asset reliability over the long term. As a result, when maintenance practices were implemented, it often meant adopting expertise developed in other industries as that was where the best information could be found.

In 2001, an initiative was undertaken by the Distribution department at the FEU (which later joined the Transmission group to become Operations) to better understand the failure modes of the natural gas delivery assets and the effectiveness of the maintenance procedures in place at that time. The results of this initiative included the centralization of operations and maintenance administration, and of maintenance planning and scheduling. Complementing this was the introduction of in-line inspection programs and risk-based natural hazards inspections, as well as a shift to a continuous improvement approach to maintenance administration.

The move to a more centralized approach was made possible by the implementation of the Plant Maintenance module of SAP (SAP-PM), which went live in 2002. These changes improved the degree of collaboration, data sharing and analysis being performed, and also led to the identification of opportunities for efficiency improvements with respect to maintenance programs. As well, the collection of data specific to individual pieces of equipment such as operating conditions that impact performance, failure types and causes, and other general attributes of the natural gas assets became feasible.

As time progressed, history began to be collected for specific assets which in turn enabled analyses to develop an improved and more detailed understanding of the natural gas assets and their failure modes. It has also laid the foundation from which appropriate means of managing the impacts of equipment failure may be identified. During this period, a number of incidents occurred within the energy industry that led to the term "Aging Infrastructure" becoming a focus within the utility industry. Concern was raised throughout North America specific to the age of much of the infrastructure that enables current life style and supports commerce throughout the region. Efforts were made to develop an understanding of the impacts of aging infrastructure and through this, it was determined that a more forward looking view of asset condition and reliability was required. In order to enhance the FEU's ability to manage the lifecycle of its assets, the FEU proposed a long-term capital planning approach, or the "Long Term Sustainment Plan" (LTSP).

As a result of previous work toward developing a LTSP, it became apparent that the scale of the challenge was such that it required the full-time dedication of assigned personnel to create the first iteration of the LTSP. In 2012, a project team was convened. The team comprised of individuals with more than 130 years of cumulative Operations and Engineering experience in more than 40 positions within the company. The LTSP was made possible by the experience, varied backgrounds and full-time dedication of the team.

The LTSP's objectives are to:

- Gain an increased understanding of asset condition and future reliability of natural gas delivery assets;
- Develop a sustainable methodology to identify and prioritize capital work as much as 20 years into the future; and
- Implement and use the methodology to create a detailed sustainment capital forecast for 2014 and 2015, and a prioritized list of future projects and programs.

During the course of the project the team developed a fundamentally different approach towards the concept of "aging infrastructure". In gaining an understanding of asset condition and the impact of age, the team realized that in fact age is not the causal factor which affects the probability of failure. Rather, the probability of failure is determined by the presence of threats such as corrosion or natural forces which act on the pipe. Corrosion is dependent on factors including coating and mitigating measures such as cathodic protection. Steel pipe that is properly coated and has effective cathodic protection has little threat of corrosion and can last virtually forever. Polyethylene pipe (PE) was expected to last 35 to 40 years when it was first installed in the early 1980s. However, samples of PE of this age removed from service in 2011 were tested by an independent laboratory and showed no degradation in their performance. Thus an asset's risk is dependent on the presence of threat factors which the project team has identified through literature, experience and expert knowledge. This approach ensures resources are allocated to where they are most effective at mitigating threats to pipe condition, maximizing the cost-effectiveness of each dollar spent and optimizing the service life of assets.

In the previous RRA, the elements of a LTSP were defined at a conceptual level. With the actual implementation of the LTSP, the elements of the plan have been redefined in terms that more closely reflect how the plan was set up. These elements are:

- Data
- Methodology
- Tools
- Results

The following sections provide a discussion of each of these elements and how they combine to form an effective and defensible means of identifying future sustainment capital work.

It should be noted that the term LTSP has been useful in identifying the need to address a more long range view of asset management and as a means of coordinating the initial work. However, long term planning and effective asset sustainment are key points in the FEI asset management program. Accordingly, as the long term planning is operationalized it will cease to be a standalone initiative and simply be a part of the overall asset management program.

1.2 ELEMENTS OF THE LTSP

1.2.1 Data

The basis of any analysis or decision making process is the availability and quality of information. Thus an important element of the LTSP is the data input. The data sources selected are discussed below. The LTSP has obtained the best information available at the time of development, incorporating data from a multitude of sources that is objective, current and supportable.

The main source of data for the LTSP is the enterprise Geographic Information System (GIS). It provides objective data, such as operating pressure, install date, and physical properties, on all of the FEU's underground pipeline lineal assets. Write access for this data is strictly controlled, and updates are made as per long-established procedures that require installation documentation or other records. The GIS data is updated constantly and is the most current representation of FEU's gas distribution and transmission systems. The assessment software used for the LTSP is set up such that it can extract information in real-time from the GIS, ensuring that only the most current information available is used for the assessment.

Other sources of data used include the FEU's historical records, BC Government mapping data, and field reports documenting the actual observed condition of assets. Field reports of asset condition are given strong consideration within the risk assessment criteria. Recent initiatives underway to organize, validate, authenticate, and digitize historical records (e.g. Gas Asset Records Project) have also provided a valuable source of information. These aforementioned types of information either originated from qualified internal staff or came from reputable external sources, and are supported by documentation.

A key value provided by the LTSP has been the consolidation of information from numerous operating groups and external organizations, and the ability to analyze the relationships between what were previously disparate data sets. Information that was previously only available within individual departments and external organizations is now available via the tools provided by the LTSP to aid decision-making. The information will be used for identifying areas of concern and making informed decisions.

1.2.2 Methodology

The second critical element of the LTSP is the risk assessment methodology. Risk is defined as follows:

$$Risk\ of\ Failure = Probability\ of\ Failure\ \ X\ \ Consequence\ of\ Failure$$

Failure is defined as:

- an unplanned release of gas to atmosphere, or
- an unplanned loss of ability to deliver gas to customers without interruption.

The objective of the LTSP is to ensure continued safe and reliable delivery of gas to the FEU's customers in the most cost effective manner. To achieve this, the team created a sustainable and consistent methodology that evaluates, for each asset, the relative probability and consequences of a failure which together reflects the level of relative risk present in the FEU's assets. The relative probability, consequence and risk are expressed by means of a numerical score. The risk "score" is calculated as the product of the corresponding probability "score" and consequence "score". This risk score assists in determining 20-year planning priorities by which assets are evaluated in detail by skilled Asset Management staff and further actions, if necessary, are defined and scheduled.

The probability, consequence and risks are all expressed in relative terms, not in absolute terms. The FEU have had few significant asset failures so the limited statistics available are insufficient to determine absolute probabilities of failure applicable to the FEU's distribution system with any accuracy. Statistics based upon the experience of other jurisdictions are also of limited relevance because there are variables that are unique to every operating company, such as pipe materials, operating conditions and history. Probability, consequence and risks expressed in relative terms, based upon the project team's experience and expertise and engineering judgment from outside the team, are considered valid alternatives. The project team's methodology does not seek to predict where and when the next failure will occur, but rather aims to objectively compile all available information regarding an asset and its environment and place it in context relative to other similar assets. The ability to evaluate all assets on an equal and relative basis lends itself to making prudent and cost effective decisions to allocate resources where they are most needed.

Both the probability and consequence of failure are evaluated by splitting each into a hierarchy of weighted sub-categories which are simpler to evaluate independently using concrete data. This hierarchy can be described as an arrangement similar to a rooted tree, with the higher levels describing generic categories of possible threats to an asset and each subordinate level becoming more numerous and describing specific failure modes that each relate to its generic parent category. Refer to Figures C3-1 and C3-2, below for an illustration of the hierarchies. The probability of failure is measured by the presence of *Threats*[1] that have the potential to compromise the safety, reliability and integrity of the asset. *Threats* were defined by the project team through literature, experience and expert knowledge, and represent the main mechanisms by which an asset would fail. A brief description is provided in the next section. *Threats* are further divided into sub-elements called *Threat Factors*. *Threat Factors* represent data factors relevant to the probability of failure in the fashion defined by the applicable *Threat* and are scored based on data attributes extracted from various data sources. For example, Pipe Material would be a *Threat Factor* relevant to the Corrosion *Threat.* The relative meaning and importance of each *Threat Factor* to the *Threat* in question is subject to the project team's expert opinion and analysis of available history. A weighted *Threat* score is calculated from the factor scores. Similarly each *Threat* is also evaluated relative to other *Threats* in its impact on the overall probability of failure and a *Probability of Failure* score is calculated accordingly. The consequence of failure is also evaluated using a hierarchical process via *Consequences* and sub-factors *Consequence Factors*, to derive a weighted *Consequence of Failure* score. The final risk score is the product of the *Probability of Failure* and *Consequence of Failure* Scores.

[1] The definition of *Threat* here is intended to be consistent with the definition of *Hazard* within CSA Z662-11, where it is defined as "a condition with the potential for causing an undesired consequence". The difference in nomenclature arose due to other reference literature used by the project team, but for all intents and purposes the terms *Threat* and *Hazard* can be considered interchangeable here.

Figure C3-1: Illustration of Probability of Failure Analytical Hierarchy

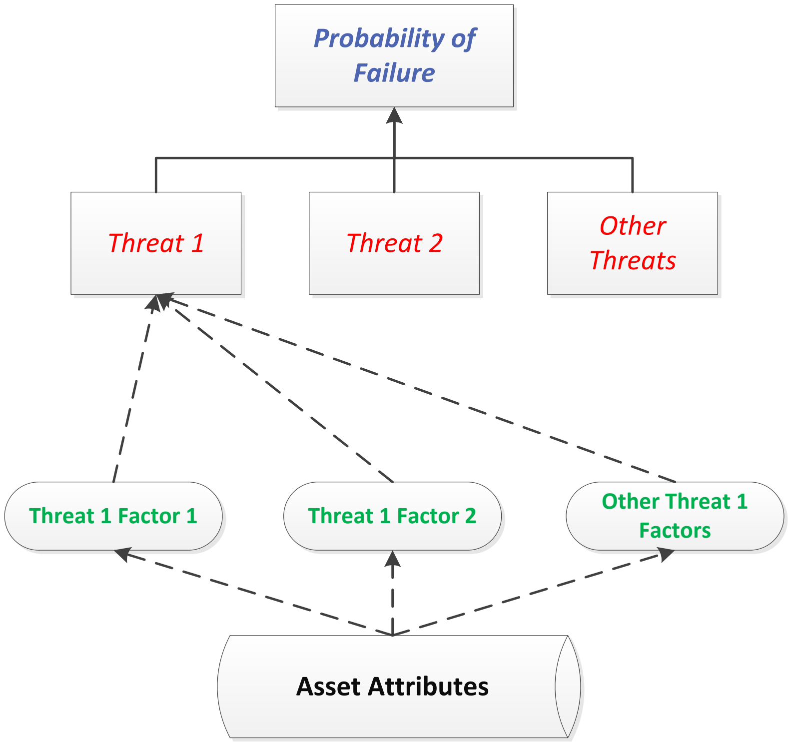
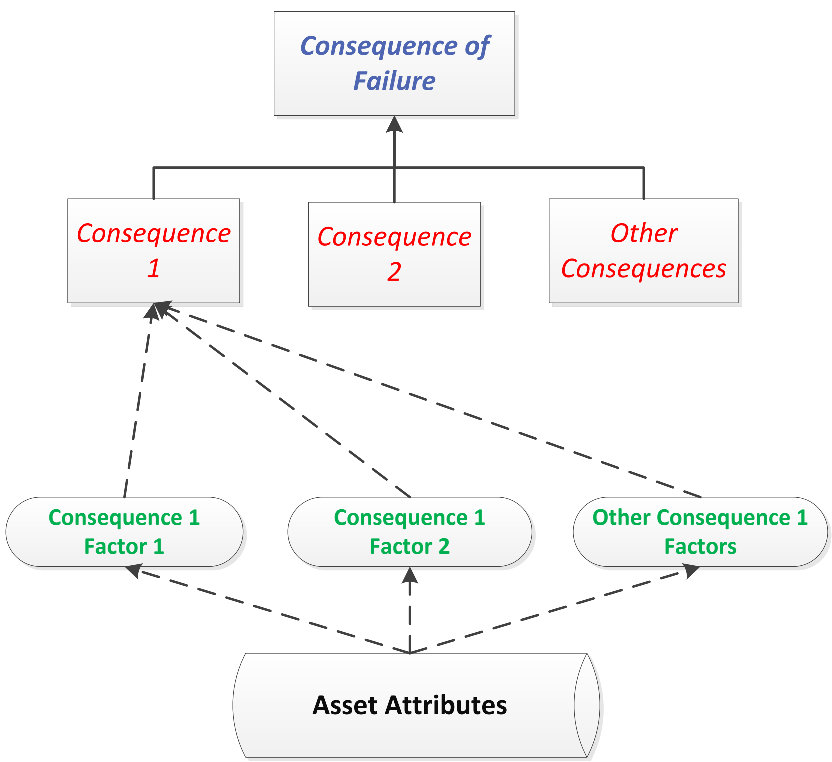


Figure C3-2: Illustration of Consequence of Failure Analytical Hierarchy



It is important to note that identifying assets as having a high relative “risk score” does not mean there is an imminent risk of failure. A high “risk score” is only a relative ranking of areas of interest. This knowledge will permit the company to become even more proactive by addressing areas of interest before they develop into failures. Skilled staff will use this information in conjunction with inputs from ongoing Integrity Management activities to investigate areas of interest further and make decisions regarding potential mitigating actions.

The algorithms and criteria used are unique to the FEU, though the general approach is consistent with transmission pipeline risk management practices and the elements of CSA Z662, Oil and Gas Pipeline Systems, Annex N, Guidelines for Pipeline System Integrity Management Programs. Annex N details requirements relating to knowledge, identifying threats, and evaluating and ranking risk. The *Threat* and *Consequence* criteria are developed based on multiple reference sources, including relevant publications, practices in other jurisdictions, and the experience of the team and other internal experts. For example, the main *Threats* are derived from the incident cause categories typically used in the industry, notably the US Department of Transportation Pipeline and Hazardous Materials Safety Administration.

The FEU’s model is unique because every distribution system has its unique challenges, and therefore a customized model is more effective at addressing risks pertinent to the FEU’s system. For example, many distribution systems of other utilities contain cast iron pipe whereas the FEU’s system does not. The FEU’s model is built to address small incidents down to routine leaks, because such a model conservatively addresses all possible incidents that are hazardous to the public and is driven by pipe integrity. Typical models that address only pipeline incidents that cause injury or fatality place a majority of weight on third party activity and improper operations and only minor consideration of other issues. This distribution of weighting is not compatible with the intent of the LTSP, which is to drive Asset Management decisions on assets based on condition rather than external activity. Therefore, a customized model addressing all leak events is more suitable for the LTSP’s purposes. Risks directly associated with operating errors and external interference are addressed by the FEU’s ongoing Integrity Management Program.

The *Threats* and *Consequences* documented below are the result of the first iteration of the LTSP process. As improved information and knowledge becomes available, these *Threats* and *Consequences* and associated algorithms will be updated. The framework established by the LTSP is by no means static; the FEU will continually improve and update the model.

PROBABILITY OF FAILURE – THREATS

The relative probability of failure is calculated via a weighted average algorithm that sums the incremental likelihood that the given asset will fail in the fashion defined by each *Threat*. These individual *Threat* scores are in turn scored by analyzing applicable asset data via *Threat Factors*. The types of *Threats* evaluated are:

Threat	Description
Corrosion	This threat relates to the gradual deterioration of pipe material by chemical reaction with its environment. This threat is evaluated based on mitigating measures such as coating and cathodic protection, and direct observations reported by field personnel.
Equipment Malfunction	Certain models or types of equipment are known, through experience, to be prone to leaks or fail to function as intended. In other cases, the equipment may be obsolete or no longer fit for purpose.
Material/Joint Failure	This threat relates to joints such as welds or fittings between pipe segments. Specific weld processes have been identified to be more vulnerable to seismic events. Certain types of tees and fittings, such as mechanical fittings, are also known to be vulnerable.
Excavation/Third Party Damage	Increased third party activity in the vicinity of pipe translates into increased probability of the pipe being hit or punctured. The FEU repairs all damage that it is aware of, but on occasion a third party may damage a pipe and not report it to the FEU. Damaged pipe has an increased probability of failure.
Natural Forces	This threat relates to the possibility of pipe being damaged or ruptured by ground or water movement.
Leak History	Industry experience indicates that where there have been previous leaks; additional leaks are more likely to develop. This indicates that local conditions are conducive to further corrosion or other factors, depending on the leak cause. It is a relative indicator of pipe condition.
Loss of Supply	This threat is relevant to areas which are known to have debris within the gas pipe. The debris may cause blockage of pipe or equipment failure.

It is important to note that age is not considered a *Threat*. For the assets under consideration, age in itself does not cause failure. Failure is caused by the presence of *Threats* as identified above. Imagine a piece of steel pipe enclosed in a box with an inert atmosphere. Without the effects of oxidation, external physical force or internal pressure, nothing would happen to the pipe; the passage of time would have no effect on a pipe’s condition. In the absence of other *Threats*, there is no justification for attributing an increase in the probability of failure on the basis of age alone.

Many of the *Threats* identified are independent of time, but it can be argued that Corrosion acts over time. However, age neither indicates the rate of corrosion or when corrosion was initiated or even if corrosion is present. At best, age is only used to infer the current condition of an asset under an assumed steady rate of corrosion. It is possible for an old pipe to have minimal corrosion and it would be incorrect to assign an increased Corrosion threat score due to age. It is far more relevant to evaluate factors that directly affect corrosion rate, such as pipe coating and cathodic protection, and where possible, the actual observed condition of the asset from field reports.

The installation date of an asset is still a consideration, not as an indicator of age but rather as a means of determining characteristics that impact the probability of failure. It is not the age of the asset that influences the end of its service life but a manufacturing or installation technology that results in the asset's failure. For example, during the 1960s, the FEU purchased and installed a significant amount of steel pipe that was factory coated with a polyethylene tape. Experience has shown that this tape is prone to disbondment, or loss of adhesion with the pipe, resulting in a void forming between the pipe and tape layers and potentially trapping in water that increases corrosion. Furthermore, the disbonded tape material can also result in shielding of the cathodic protection system; the polyethylene tape actually prevents electrical current from the cathodic protection from reaching the bare pipe underneath the void and renders the cathodic protection ineffective. These factors will result in conditions that enable corrosion to occur. As with many similar failure modes, the issue is the type of pipe coating rather than the pipe's age. Coal tar enamel coated pipe from the same era that has not disbonded continues to serve well and is expected to continue to do so for some time into the future. Age is not the causal factor; the manufacturing method of the era is.

CONSEQUENCE OF FAILURE - CONSEQUENCES

The relative consequence of failure is calculated via a weighted average algorithm that reflects the different means by which an asset failure can impact ratepayers and other members of the public. The different categories of *Consequence* evaluated are:

Consequence	Description
Financial	This measure measures the rate impact to customers by evaluating the residual book value of each pipe. The premature retirement of an asset before it is fully depreciated is undesirable. If a pipe fails, the net effect is equivalent to the premature retirement of the failed pipe. The net result of a premature asset retirement is that there will be a net increase, proportional to the residual value, in the Cost of Service for the customer. The methodology only identifies areas of interest for further assessment by Asset Management staff. By assigning a higher consequence to pipes with relatively high residual value, it incents the FEU to proactively address serious threats in newer pipes before conditions deteriorate and allows Asset Management to be cognizant of the relative rate impact when considering pipe replacement.
Public Safety	This measure evaluates the potential for any incident to impact the well-being of the public. This is dependent on indicators such as population density in the vicinity of the pipe and pipe operating pressure.
Difficulty of Repair	This measure evaluates the difficulty of restoring a given pipe segment back to service in the event of a loss of integrity. Factors considered include pipe diameter, pressure and location.
Security of Supply	This measure evaluates the potential for service outages to downstream customers if a pipe segment were taken out of service. The loss of a critical pipe segment may impact system wide pressures.
Regulatory Intervention	This measure considers the potential for increased regulatory scrutiny, the introduction of onerous regulatory requirements and penalties if a failure were to occur on a given pipe segment.

The above threats and consequences are not comprehensive. There are additional threats and consequences which were evaluated but deferred for future implementation due to incomplete data or time constraints. Please refer to Section 3.0 below for more information on Next Steps.

The central principle during the development and application of the above *Threats* and *Consequences* is always to ensure the safe and reliable delivery of gas to customers at reasonable cost. The customers' interests are always the foremost consideration. For example, the *Financial* consequence evaluates the negative impact to the ratepayer of a premature retirement of an asset, thereby enabling Asset Management to weigh these customer impacts in its decision making.

Each *Threat* is scored via applicable *Threat Factors* and defined scoring criteria, then normalized to 10. A weighting is then applied to each *Threat* to reflect its relative importance. Finally each weighted score is summed to provide a "*Probability of Failure*" score. The "*Consequence of Failure*" score is calculated in the same manner. The final risk score is the product of the *Probability of Failure* and *Consequence of Failure* Scores as per the following algorithm:

$$Risk\ of\ Failure = \sum \begin{pmatrix} Threat\ Score \\ x\ Normalization\ Factor \\ x\ Threat\ Weight \end{pmatrix} X \sum \begin{pmatrix} Consequence\ Score \\ x\ Normalization\ Factor \\ x\ Consequence\ Weight \end{pmatrix}$$

1.2.3 Tools

The project team implemented software tools capable of consolidating all the data sources and applying the risk assessment methodology to the FEU's entire gas system to identify areas of interest. These tools make it possible to conduct a consistent comparison of thousands of assets and can facilitate effective Asset Management decision making for asset service life optimization.

The primary tool used to conduct the risk analysis is the Geospatial Analysis application (GSA) from General Electric. The GSA application is an add-on to the FEU's existing GIS software. It is capable of extracting data from multiple sources, applying scores as defined by users, and overlaying the results onto geospatial data for a visual representation of the results. The project team worked closely with the vendor to configure the custom risk algorithm with the score calculation. The GSA application was able to apply the risk algorithm at a very detailed level; down to individual pipe segments. The results from the GSA application identify relative risk scores for each piece of main within a specified area.

A secondary tool developed was a database application using Microsoft Access. This database enabled the manual analysis of other asset classes and paralleled the risk calculations of the GSA application. This is necessary because the GSA application is currently not configured to access the transmission module of the GIS software, and much of the data regarding transmission pressure (TP) pipelines and stations exist in documents and other formats not easily imported into the GSA. One example would be historical leaks on transmission pipelines;

they are documented manually in incident reports rather than plotted in the GIS system. Slight changes were included to address differences in assets and in the data available.

Like the GSA application, the results of the database identify risk scores for each asset relative to the other assets of the same type.

1.2.4 Results

The final element of the LTSP combines the data, methodology and the capability of the software tools to produce a holistic risk assessment of all of the FEU's gas assets. The results of the relative risk assessment have been validated and the FEU will use these results, in conjunction with inputs from its ongoing Integrity Management activities, to direct its asset risk mitigation efforts efficiently and cost-effectively. Separate sets of relative risk scores were generated for different asset classes and provide a means of identifying which assets should be considered first by skilled personnel. The GSA application produced an assessment of over 300,000 distribution pipe segments. Sustainment projects can be scoped down to individual pipe segments where appropriate. The Microsoft Access Database produced rankings of stations and transmission pipeline segments. Assets with conditions that warrant further analysis or investigation as indicated by a high relative risk score are brought to the attention of Asset Management staff. Skilled personnel will select a course of action that is appropriate and effective for the specific concerns under consideration. It is important to note that the LTSP results provide additional data to assist Asset Management staff in making decisions. Decisions are not made based on results from the LTSP alone. There is still a need for expert judgment before the work is assigned, and, where appropriate, the work may entail mitigating actions rather than pipe replacements.

The risk assessment results also present great opportunities for year-to-year comparisons of the system health and for identifying project synergies both internally and externally. The project team held a series of information sessions with selected municipalities to share information regarding anticipated work, including the municipalities of Burnaby, Coquitlam, Richmond, Vancouver, New Westminster, Penticton, Castlegar, Trail, Nelson, Metro Vancouver and the Regional District of Central Kootenay. Many municipalities are also undertaking long term plans of their own and synergies exist for sharing costs. The FEU, working through local Operations Managers, will continue to improve information sharing and cooperation with municipalities to realize those synergies. An example of such synergy would be to coordinate the timing of work with municipal projects such that only one pavement repair is required. Through ongoing communications and improved information sharing, the FEU believe that reduced paving costs will continue to benefit both customers and municipal taxpayers while at the same time reducing inconveniences for residents.

VALIDATION PROCESS

The project team undertook a validation process on the methodology, tools and results of the LTSP and is confident that the results generated provide a reasonable assessment of the relative risk of the FEU's natural gas delivery assets. The risk assessment methodology had been validated at multiple points of the development process by engineering and operations representatives. The programmed algorithms in the GSA application and Microsoft Access Database were verified by both checking programming code and manually calculating dozens of randomly selected samples.

The weighted algorithm that underlines the current risk model was examined closely in order to provide insight into possible limitations of the model including biases, inadequacy, discontinuities and imbalances. Specifically, the overall algorithm was tested in terms of whether it reacts appropriately to changes in any and all variables through a statistical analysis utilizing a Monte Carlo simulation. A biased algorithm would lend disproportionate influence to certain factors and erroneously shift the distribution of scores to overestimate or underestimate risks. The Monte Carlo simulation confirmed that the current algorithm did not introduce bias.

The resulting risk scores and relative rankings were validated with the Operations staff in all areas of the province. The GSA application's results consistently matched problematic areas identified by Operations personnel. Recent leaks matched those mains identified in the top 10 percent of "Probability of Failure" scores.

2. IMPACT ON SUSTAINMENT CAPITAL EXPENDITURE

The development of the LTSP has enhanced the FEU's understanding of the risk factors relevant to pipe failures. The reality is that a significant proportion of the FEU's assets, due to the technology and practices used in the era of installation, do possess characteristics which have been demonstrated through experience to be a concern so replacement may be more reasonable than repairs and mitigation. The LTSP results also bring to the forefront indications of asset conditions that warrant mitigation, whereas in the past Asset Management may not have had the capability to pinpoint these concerns before they develop into leaks. In order to act proactively on this data, the FEU are seeking to increase its resources in order to execute an increased level of sustainment capital expenditure over the long term.

FEI has challenges in obtaining resources to execute an increased level of sustainment capital in 2014. Therefore for 2014 FEI forecasts maintaining the same level of sustainment capital expenditure as in 2013. For 2015-2018, FEI is forecasting to gradually increase sustainment capital by an average of $1 million per year starting in 2015 to a total of $82.3 million in 2018. Regardless of the level of expenditures, the process enhancements developed by the LTSP have been applied towards developing a list of capital replacements to be undertaken during the PBR period and will be an integral part of FEI's capital planning processes for future years.

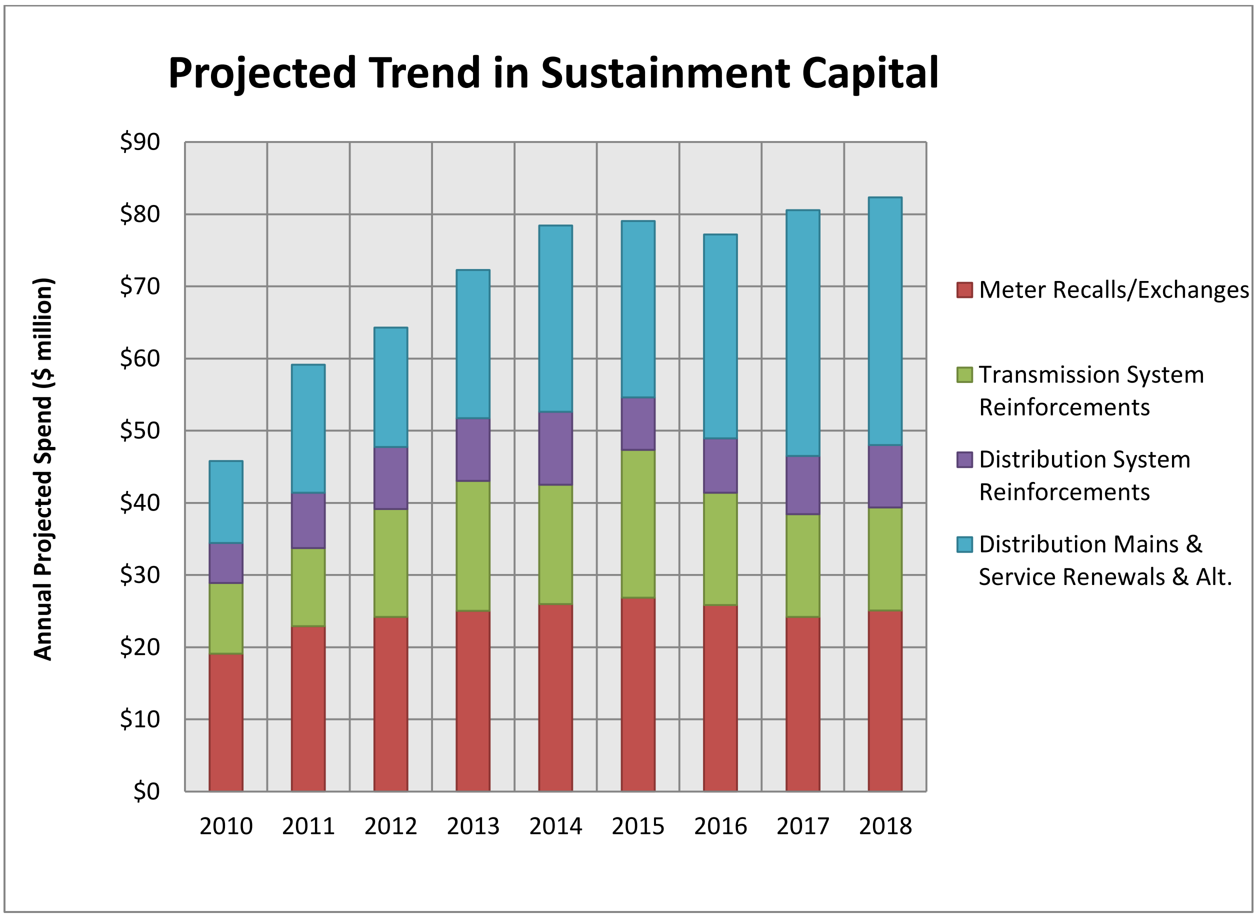
Using the LTSP together with additional analyses/investigations by Asset Management personnel, FEI has also identified a number of projects and programs expected to exceed the CPCN threshold. These projects involve larger IP system upgrades and TP pipeline replacements. They are documented in the CPCN section of the Application found at Section C4.7.

The LTSP enhances the FEU's Asset Management and capital planning processes and works in conjunction with the FEU's continuing Integrity Management Program (IMP). The FEU's IMP activities work to prevent, monitor and remediate hazards/threats that can potentially impact the operation and integrity of its assets. Selected IMP activities such as In-Line Inspections may rely on quantitative risk assessment methods which are common practice. Requests for sustainment capital work may arise directly from IMP activities, and data from IMP activities can be a valuable input into the LTSP. The LTSP can also support IMP activities by directing attention to areas of interest.

Contrary to the framework outlined in the previous RRA, the project team found it impractical to define a strict level of risk exposure beyond which action would be triggered. Risk is subjective and the timing and location of failures cannot be predicted with absolute certainty. It is not feasible, and may not be possible, to reduce risk to zero. In every system there always exists a non-zero risk of an undesirable outcome, and the marginal increase in cost of service for mitigating actions must be balanced against the marginal reduction in risk. The team's approach was not to define what an "acceptable" level should be, but rather to ensure the FEU undertake reasonable and effective measures to enhance its ability to maintain safety and reliability over the long term. The decision on whether to replace an asset based on its risk level is still subject to the judgment of experienced staff, not a mathematical formula. The output of the LTSP provides an additional tool that helps ensure that the FEU's asset sustainment capital is spent on projects that deliver the highest relative cost-benefit. The mains with the highest relative risk scores are continually addressed. With future annual iterations of the risk assessment, improved data and comparisons will be available to judge the effectiveness of the risk mitigation measures and the level of expenditures will be adjusted accordingly to achieve a balance between risks, customer impacts, the FEU's ability to execute work, corporate strategy and external factors.

The projected Sustainment Capital Expenditures and Base Capital are shown in Figure C3-3. This projection is based on project-specific estimates of pipe replacements in areas of interest. Further work is still required to refine the estimates. Nevertheless, it provides an enhanced level of accuracy compared to previous projections and represents a reasonable and prudent level of expenditures to support the continued safe and reliable delivery of natural gas to FEIs customers.

Figure C3-3: Projected Annual Capital Spend (FEI: 2013-2018)



3. NEXT STEPS

This is the first iteration of the entire risk assessment process and FEI expects that all elements of the LTSP will continue to evolve and improve as more experience and knowledge is gained.

For example, a number of additional *Threat* and *Consequence* factors were identified during the development process, but were ultimately deferred due to incomplete or missing data, or time constraints. One such Threat Factor would be to use slope grade as a proxy for possible landslide hazards. Topological information currently in the FEU's GIS systems can be used to calculate slope grading and identify steep areas; however, further analysis is required to implement such a calculation in the GSA software and to determine the applicability of the information. Other potential threat and consequence factors may also be included in future enhancements to the methodology, but similar to the above example, further analysis would be required to determine the quality of the underlying data, availability of the data and updates to it, and also how to identify an appropriate measure for the factor across the FEU's natural gas delivery assets.

The improved forward visibility and ability to plan work attained by the LTSP will allow the FEU to work more closely with municipalities and other utilities to leverage synergies between projects. The FEU will continue to maintain positive relationships with these parties to realize these benefits.

Through adopting a continuous improvement philosophy, considering a longer-term planning horizon (a 20-year outlook), and also collaborating with municipalities and other utilities, the LTSP will continue to support the ongoing operation and maintenance of a safe, reliable natural gas delivery system.

Appendix C4

IT CAPITAL DIRECTIVE

RESPONSE TO 2012-2013 RRA DECISION BCUC DIRECTIVE NO. 42

In this Appendix, FEI provides a response to Directive 42 in the 2012-2013 RRA Decision related to IT capital expenditures. Directive 42 states:[1]

> *In the view of the Panel, an increase in IT capital expenditures in the future should be remedial in nature, and demonstrate a clear ability to correct inadequate operational matters or reduce other operating costs from the status quo.* ***Therefore, the Commission Panel directs the FEU in future RRAs to clearly identify either a shortcoming in current customer service levels or provide a fulsome budgeted O&M cost reduction, including the year of realization of expected savings, resulting from each significant IT Capital project in order to justify spending requests****.*

In accordance with this directive, FEI's approach to discretionary IT Capital projects results in all significant projects (i.e. over $500 thousand) being justified based on customer service or financial benefits or both. FEI will continue to apply this approach throughout the PBR Period. It is important to recognize, however, that IT Capital projects are justified based on a number of other drivers, such as safety and risk management, and that it is often to difficult to quantify financial benefits of all projects. FEI provides a description of its approach to planning IT capital expenditures below.

In response to the Directive above and as the next step in the adoption of Project Portfolio Management (PPM)[2] for IT capital investments, FEI has implemented a Benefits Management practice primarily for business technology transformation and business technology enhancement projects. Over the PBR Period, these categories of IT capital expenditures are expected to total approximately $10 million annually. The other IT capital expenditure categories are in the nature of sustainment activities for existing information systems (the categories of infrastructure sustainment, desktop infrastructure sustainment, and application sustainment), which are evaluated more on managing risk to asset integrity and sustainability not necessarily on financial or productivity benefits.

The Benefits Management practice supports the identification and selection of the right projects for execution at the right time, and it facilitates the monitoring and reporting of any expected benefits identified in the business case. Benefits within IT capital investments will typically include but are not limited to improving public and worker safety, addressing potential shortcomings in customer service levels and driving O&M cost reductions or containment.

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[1] 2012-2013 RRA Decision Directive 42 Page 102 and Appendix A Page 8.

[2] PPM is a recognized discipline for managing project portfolios that facilitates the evaluation, prioritization and coordination of the requirements of the various operating business units and technologies enabling effective capital investment decisions

IT projects must be aligned to the Company's strategic goals of safety, customer service, reliability and efficiency. Each project is required to demonstrate how it supports the achievement of organizational goals and priorities. PPM compares and prioritizes potential project investments based on the project's contribution to the organization's goals, irrespective of where or when the initiative originated. The priority of each project guides the financial and resource allocation for the portfolio. Prioritization assures projects with the higher value to the Company will be considered first when allocating finite resources. The Benefits Management Practice supports the business case and investment analysis. This practice compares the actual benefits achieved from a project against those anticipated (planned) in the business case. The benefits are measured for the entire lifecycle of the business technology investment.

The prioritization and selection of projects for following year are conducted and completed by the fall for the upcoming year. Currently, FEI has a completed list of projects for execution within the 2013 portfolio, but not for 2014. Since 2013 forms the base for the PBR Period spending, FEI is providing information on the 2013 portfolio in support of the Commission's Directive regarding justification of spending requests.

Highlighted below is a list of the 2013 portfolio approved Business Technology projects driving a variety of quantitative and qualitative benefits. Several of these projects span multiple fiscal years but the expected spend in 2013 is $11 million which is in keeping with the 2013 Projection. Some of the projects have financial returns as seen in the Tangible (Financial) Benefits column but there are many other drivers of Business Technology projects namely how the project supports the alignment of the Utilities, enhancement of customer service, safety, introduction of new products and services (Growth), maintenance of a safe and reliable gas distribution system, support of employees and mitigation of business continuity / IT risk. All of these strategic drivers were considered when selecting the right mix of projects for execution. Where a check exists, the project represents an alignment to the respective strategic driver.

Table C4-1: 2013 Project Portfolio Benefits

Project Name	Value $ (000s)	Integration	Customer Service	Growth	Safety	People	Financial Benefits (000s)	Risk
GeoSpatial Program - eForms	$2,400				✓	✓	$2,800	✓
Geospatial Program - GIS Toolset Refresh	$2,800	✓	✓	✓	✓	✓	$1,000	✓
Customer Portal and Bill Redesign	$1,600	✓	✓		✓	✓	$2,500	✓
Knowledge Management Program - SharePoint Upgrade and Migration	$1,307	✓					$1,700	✓
Knowledge Management Program - Integrated Intranet	$1,277	✓	✓		✓	✓		✓
Financial Consolidation & Enterprise Reporting Solution	$1,148			✓	✓	✓	$1,000	✓
Incident Management System	$1,000	✓			✓	✓	$1,075	✓
Knowledge Management Program - New Business Solutions	$800	✓	✓		✓	✓	TBC	✓
Knowledge Management Program - Small & Medium New Builds	$600	✓	✓		✓	✓		✓
2013 Customer Service Enhancement	$1,971	✓	✓	✓			$750	✓
ClickSchedule Business Enhancement	$512		✓		✓		$585	✓
2013 SAP BI-BW Enhancement	$231				✓	✓		✓
2013 GIS (GE Smallworld) and Mobile GIS (Tensing) Enhancement	$225				✓			
2013 Operations Enhancement	$220		✓					✓
Contractor Access to Planning Systems	$143			✓	✓		$100	✓
2013 Supply Chain Enhancement	$133	✓	✓					✓
2013 Finance Enhancement	$120			✓		✓		✓
2013 BC One Call Enhancements (includes DCRS)	$110				✓			
2013 Meter Management Enhancement	$108	✓	✓	✓	✓			✓
Web optimization templates and mobile	$99	✓	✓	✓	✓	✓		
2013 Filenet Enhancement	$90				✓			
2013 Forecasting Enhancement	$85	✓	✓					✓
2013 WINS Enhancement	$55			✓				
2013 Entegrate Enhancement	$25				✓	✓		✓
2013 McLaren Enterprise Engineer Enhancement	$22	✓	✓		✓			
	$17,081						**$11,510**	

Detailed below are descriptions of each of the drivers detailed in the table above.

- Integration. Extent to which the project supports an opportunity to leverage, align, and improve upon the Utility's capabilities through the integration of its people, processes, and/or tools across the organization. By integrating people, processes or tools across multiple departments or the entire organization, FEI will achieve greater operating efficiencies and in return reduced departmental budgets over time.

- Customer Service. Extent to which the project supports customer service strategy ensuring first contact resolution and enhanced customer experience with respect to FEI's products, services, and employees. These efforts will better enable FEI to support the achievement of first contact resolution and address any identified shortcoming in current customer service levels.

- Growth. Extent to which the project serves to diversify service offerings and support the maintenance and/or growth of the core energy delivery footprint to meet customers' needs. Growth, either by extending the core energy delivery footprint or by diversifying service offerings, should generate new revenue streams that will potentially allow FEI to offset (future) budgetary pressures.

- Safety. Extent to which the project supports FortisBC's commitment to enhance public and worker safety in its operations. For instance, the BC One Call system changes helped FEI reinforce public safety by driving awareness and providing quick response times to inquiries; while automated vehicle location (AVL) promoted employee safety by improving the timeliness and accuracy of locating FEI vehicles.

- People. Extent to which the project supports efforts to attract, retain, develop, train, motivate, and engage the right people and/or supports the capture and transfer of knowledge to ensure there is a sufficiently skilled workforce, management, and leadership to meet business needs. Having the right people, motivated and engaged in the right activities, should help FEI drive greater operating efficiencies, and retaining the right people should facilitate FEI in acquiring a knowledgeable and experienced workforce, thus reducing departmental budgets over time.

- Financial Benefits. Degree to which the project serves to provide value to the organization, its customers and/or shareholders through financial benefits, such as increased revenue generation, improved productivity (operating efficiencies), reduced costs, and/or cost avoidance. Generally the benefits reflect a minimum of a five year analysis period.

- Risk. Extent to which the project facilitates the protection and/or maintenance of business systems, processes, and associated data and considers current and emerging Business Technology standards, policies, methodologies, and roadmaps. By ensuring upcoming projects / initiatives align to a long-term roadmap and vision, FEI should achieve greater integration and standardization of its technology architecture, backup and recovery strategy and data sharing, thereby providing FEI opportunities to gain efficiencies in vendor management, reduce costs in software maintenance, and avoid business losses and service disruptions from technology systems interruptions.

As seen above, all discretionary IT Capital projects over $500 thousand are evaluated and justified based on customer service or financial benefits. However, there are a number of other important drivers that enable a more fulsome benefit statement, namely Integration, Growth, Safety, People and Risk. Two examples of significant projects that do not have demonstrable

O&M savings but deliver strong benefits in Customer Service and the other supporting drivers are the Integrated Intranet and Small and Medium New SharePoint site Builds. These projects directly support the ready and accurate access to information for the customer service teams in their dealing with customers through various communication channels. Information related to rates, products, bills, promotions and other training support is all made available through these business technology solutions resulting in a more efficient, knowledgeable and accurate customer service representative. This will lead to reduced errors in customer contact, more accurate information passage and quicker resolution of their inquiry.

In support of its benefits management practices, FEI implemented three products: the benefits statement, benefits contract and benefits account. The benefits statement allows the Company to identify describe and qualify quantitative and qualitative benefits of the project during the planning phase. Next, the benefits contract monitors and controls the benefits during delivery (execution) of the initiative. Lastly, the benefits account allows the Company to track the actual achievement and variance of the quantitative and qualitative benefits at review points against the benefits originally planned. Because benefits management practices provide reporting throughout the benefits lifecycle, it will ensure continual improvement. This practice supports a repeatable and objective approach to investment analysis. This in turns drives informed decision-making regarding Business Technology projects funding requests.

It is with the adoption of PPM and the newly implemented Benefits Management practice that FEI is able to support the selection of the right projects at the right time and facilitate the tracking of their benefits. Through the benefits statement, contract and account, the realization of the benefit, whether it be operational service levels or budgeted cost reduction, will be effectively identified, committed to and reported on, thereby supporting the justification of the spending requests.

Appendix D1

PBR JURISDICTIONAL BENCHMARKING REPORT

COMPARISON OF RECENT PERFORMANCE-BASED REGULATION (PBR) FOR DISTRIBUTION UTILITIES IN CANADA

PREPARED FOR

Fasken Martineau DuMoulin LLP

5 JUNE 2013

BLACK & VEATCH
Building a world of difference.

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EXHIBITS

Research Background and Scope

An April 18, 2013 letter of the British Columbia Utilities Commission (Commission) staff required FortisBC Energy Utilities Inc. ("FEU") and FortisBC Inc. ("FBC") "to evaluate the most recent Performance-Based Regulation ("PBR") methodologies employed by FEU and FortisBC and the various PBR methodologies approved by other jurisdictions in Canada."

Pursuant to the Commission's staff letter, a study of the most recent PBR methodologies used by Canadian distribution utilities was prepared by Black & Veatch Canada Company ("Black & Veatch") on behalf of FEU and FBC with the following objectives:

- To present the Commission with the various PBR methodologies for electric and gas utilities approved by other jurisdictions in Canada.
- To evaluate and compare the identified PBR methodologies.

Except for the previous PBR plans of FEU and FBC, the scope of this study was limited to those Canadian jurisdictions where PBR plans have currently been implemented. In particular, this study focuses on Alberta's latest PBR initiative (as presented in Decision 2012-237 of the Alberta Utilities Commission or "AUC"), Ontario's 4th generation Incentive Regulation[1] ("IR") for power distributors, and the latest IR Plans of Enbridge Gas Distribution ("EGD") and Union Gas Limited ("Union") in Ontario[2]. The various historical plans of these utilities are not discussed in this study.

Black & Veatch's PBR study relied on publicly available information, which includes regulatory filings and reports available in the utility regulators' websites. This report presents the findings of Black & Veatch's PBR study. The report outlines the essential features of each reviewed plan. Based on those elements, the report finds that there are strengths and weaknesses of each plan. Further the report addresses the practicality of the plan when applied in the context of actual utility operation. In our view, certain elements of each plan have merit for consideration as part of a FortisBC Plan. However, no plan warrants consideration for adoption in total and, if elements from other plans are used, care must be taken to assure that each element adopted from other plans are consistent with the entire plan and circumstances of the particular utility. Rather, it is important to adopt a plan that reflects the operating realities of the FortisBC system.

[1] 3rd generation IR data will be used for PBR items that are not yet decided by OEB in 4th generation IR.
[2] Both Union Gas Limited and Enbridge Gas Distribution are in their cost of service re-basing year for the next generation IR Plans, therefore, this benchmark study will only focus on their 2008-2012 incentive regulation.

Alberta's PBR Plans for Distribution Utilities

HISTORY AND DEVELOPMENT

On February 26, 2010, the AUC began the process of rate regulation reform aimed at introducing PBR for electric and gas distribution utilities in Alberta. As indicated by the AUC in Decision 2012-237, the objective of the reform was twofold:[3]

> *"The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers."*

On July 26, 2011, the ATCO Utilities, EPCOR, Fortis Alberta, and AltaGas filed their respective PBR proposals for review by the AUC. After consideration of all submissions from both the Utilities and Interveners, the AUC issued Decision 2012-237 on September 12, 2012, which prescribed a common PBR formula for determining rates to all natural gas and electric distribution utilities in Alberta starting in January 2013. The approved Alberta PBR model is described in the next section of this report.

DESIGN AND COMPONENTS OF THE PBR MODEL

There were five (5) principles that were adopted by the AUC with respect to the design of its PBR model:[4]

> **Principle 1:** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2:** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3:** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4:** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5:** Customers and the regulated companies should share the benefits of a PBR plan.

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[3] AUC Decision 2012-237, paragraph 15.
[4] Ibid., paragraph 28.

It was in recognition of these principles that the AUC made its determinations with regard to the design and structure of the Alberta PBR model.

PBR Types

To accommodate the differences in the underlying cost structure and conditions between electric and gas distribution utilities, the AUC approved two PBR types: (1) Price Cap PBR and (2) Revenue Cap PBR. It was determined that both PBR types effectively decoupled revenues from the cost of service and therefore created the intended PBR efficiency incentives for the electric and gas distribution utilities[5]. As such, the AUC was indifferent to the type of PBR plan chosen by the respective Alberta Utilities.

For electric distribution utilities that normally do not face volumetric risks associated with declining use per customer, a price cap was chosen as the preferred PBR type by the electric distribution utilities. Under a price cap plan, approved rates from the previous year are escalated by the PBR formula to arrive at the upcoming year's rates. In Alberta, ATCO Electric, EPCOR and Fortis Alberta adopted price cap plans.

For gas distribution utilities that faced volumetric risks, a revenue cap in the form of a revenue-per-customer cap was chosen as the preferred PBR type by the gas distribution utilities as it "adequately addresses the issues associated with declining usage per customer without decreasing the intended efficiency incentives of performance-based regulation."[6] Under a revenue-per-customer plan, the approved revenue-per-customer from the previous year is escalated by the PBR formula on a class by class basis to arrive at the upcoming year's revenue-per-customer cap. Rates for each rate class are then derived by dividing the upcoming year's revenue-per-customer by the forecast consumption per customer.

Below are the approved PBR formulas specific to both the price cap plan and the revenue-per-customer cap plan:

Price Cap PBR Formula

$$Price_t = Price_{t-1} \times [(1 + (I - X)] \pm Z \pm Y \pm K$$

Revenue-per-Customer Cap PBR Formula

$$Revenue\ per\ Customer_t = Revenue\ per\ Customer\ _{t-1} \times [1 + (I - X)] \pm Z \pm Y \pm K$$

Where: t = current year
I = Inflation Factor
X = Productivity Factor
Y = Exogenous Factor

[5] Ibid., paragraph 141.
[6] Ibid., paragraph 143

Z = Exogenous Factor
K = Capital Tracker Factor

Length of Term

The AUC concluded that a five (5) year for each of the utilities' PBR plans was reasonable. The AUC chose this length of term in recognition that some of the elements approved in the PBR plans of the utilities in Alberta were "novel" and that it was consistent with the typical term for other PBR plans in North America. The AUC went on to state that, "although a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, the Commission has approved the inclusion of an efficiency carry-over mechanism to mitigate this effect. "[7]

The following section describes each of the approved design components of the PBR types listed above.

Going-in Rates

As a starting point to which the PBR formula is to be applied, the AUC directed the Alberta Utilities to use their respective approved 2012 distribution rates, based on mid-year convention without adjustments, as the going-in rates for the PBR term.

Inflation (I-Factor)

The AUC considered the following five (5) selection criteria proposed by the Alberta Utilities in determining the appropriate Inflation Factor ("I-Factor") for the PBR formula:

1. I-Factor must be indicative of the change in input prices that the company expects to experience over the term of the PBR plan.
2. Inflation Index must be published by a reputable, independent agency and made readily available on at least an annual basis.
3. I-Factor should be transparent, simple to calculate and easy to understand.
4. The selected I-Factor should not be overly volatile.
5. I-Factor should reflect a broad measure of inflation rather than the experience of the specific company to which the PBR plan is to apply, so that the company cannot significantly affect the index.

In light of the above selection criteria and in consideration of Alberta's unique economic realities (i.e. tight labor markets and dependencies on price-volatile commodities), the AUC approved a composite I-Factor consisting of two Alberta -specific broad-based indexes for labor and non labor costs. The composite I-Factor is based on historic actual changes.

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[7] Ibid., paragraph 836.

For labor costs, the AUC approved the use of Alberta's Average Weekly Earnings Index ("AWE"), to be adjusted year to year, in its composite I-Factor, which includes both salaried and hourly waged employees. The actual Alberta AWE for the previous July through June period provided by Statistics Canada[8] comprises the first component of the composite I-Factor for the upcoming year[9].

For non-labor costs, the AUC approved the use of Alberta's Consumer Price Index ("CPI") to be adjusted year to year. It was determined that Alberta CPI "adequately reflects the price changes for the non-labor expenditures of Alberta companies to which it will apply"[10], and its use will be consistent with the Alberta Utilities' use of Alberta CPI in their previous Cost of Service applications. The actual Alberta CPI for the previous July through June period provided by Statistics Canada[11] comprises the second component of the composite I-Factor for the upcoming year[12].

The weighting of the factors were to reflect the Alberta Utilities' historical proportion of labor to non-labor costs. In assessing the historical proportions of costs of the Alberta Utilities', the AUC determined that a 55 to 45 ratio of labor to non-labor expenditure for all Utilities should be held constant throughout the PBR term[13].

Productivity Improvement Factor (X-Factor)

For determining the productivity "X-Factor" to be applied in the PBR formula, the AUC relied on a Total Factor Productivity ("TFP") study completed by the NERA Economic Consulting ("NERA"). The NERA study relied on publicly available U.S. Federal Energy Regulatory Commission ("FERC") Form 1 data from 72 Electric and combined Gas and Electric distribution utilities in the U.S. and indexed volumetric output from 1972 to 2009 to determine productivity. The study produced a 0.96% X-Factor, which was approved by the AUC without adjustment, to be used in Alberta's PBR plan.[14]

Additionally, the AUC approved a stretch factor of 0.2% to be added to the 0.96% produced by NERA's TFP study. It was assumed that the transition to PBR from Cost of Service ("COS") regulation would produce immediate expected increases in productivity growth.[15] As such, the purpose for the addition of the 0.2% stretch factor was to share between the companies and customers these immediate expected increases in productivity growth.[16]

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[8] Alberta AWE from Statistics Canada Table 281-0028, data vector V1597350
[9] Ibid., paragraph 251
[10] Ibid., paragraph 209
[11] Alberta CPI from Statistics Canada Table 326-0020, data vector V41692327
[12] Ibid., paragraph 251
[13] Ibid., paragraph 229
[14] Ibid., paragraph 514
[15] Ibid., 479
[16] Ibid.

Accordingly, the AUC directed that an X-Factor (the sum of TFP and a stretch factor noted above) of 1.16%, inclusive of a stretch factor, be used by the respective Alberta distribution utilities in their PBR Plans.

Coverage of Expenditures in the PBR Formula

The "$[(1+(I-X)]$" portion of the PBR formula ("I-X Mechanism") determines the maximum rate at which utility prices under a price cap plan, or revenues-per-customer under a revenue-per-customer plan, can be escalated year over year. In Alberta, the AUC determined the I-X Mechanism to be applicable to all expenditures, both Operations and Maintenance ("O&M") and capital to create the same efficiency incentives as those experienced in a competitive market to the extent possible.

However, the AUC also recognized that certain exogenous factors existed that needed to be addressed outside the I-X Mechanism. The following section describes the approved flow-through rate adjustment factors that are treated outside of the I-X Mechanism.

Exogenous Factor (Y-Factor)

In Alberta, cost impacts arising from events that are beyond the company's control but are foreseeable and reoccurring may qualify for Y-Factor treatment. In determining cost eligibility for Y-Factor treatment, the following six criteria, of which all must be satisfied, have been adopted by the AUC:

1. The costs must be attributable to events outside management's control.
2. The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3. The costs should not have a significant influence on the inflation factor in the PBR formulas.
4. The costs must be prudently incurred.
5. All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

In general, Y-Factor eligible costs arise in the normal course of business, but are such that the company has no control over them. Examples of costs eligible for Y-Factor treatment in Alberta include, but are not limited to gas and electric transmission rates charged by transmission service providers, AUC assessment fees, hearing costs, costs as a result of AUC directions, municipals fees and income tax impacts other than tax rate changes.

With respect to the materiality of the Y-Factor, the AUC determined that it should be consistent with the threshold set for the Z-Factor. In particular, the exogenous event, in addition to meeting the above five criteria, must result in "the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established"[17] to qualify for Y-Factor treatment.

Exogenous Factor (Z-Factor)

In Alberta, costs or revenues associated with unforeseen events outside the control of the company, for which the company has no other reasonable opportunity to recover the costs within the PBR formula, are eligible for Z-Factor treatment[18]. The following five criteria, of which all must be satisfied, have been adopted by the AUC in determining eligibility for Z-Factor treatment:[19]

1. The impact must be attributable to some event outside management's control;
2. The impact of the event must be material. It must have significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;
3. The impact of the event should not have a significant influence on the inflation factor in the PBR formulas;
4. All costs claimed as an exogenous adjustment must be prudently incurred; and
5. The impact of the event was unforeseen.

With respect to the materiality of the Z-Factor, the AUC determined that the exogenous event, in addition to meeting the above five criteria, must result in "the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established"[20] to qualify for Z-Factor treatment.

Capital Tracker (K-Factor)

The AUC recognized the necessity to treat certain capital outside the I-X mechanism and approved the use of a K-Factor for that reason. To determine eligibility for K-Factor treatment, the AUC issued three criteria in which the Alberta Utilities must satisfy in their justification for the inclusion of their selected capital projects for capital tracking. Table 1 below summarizes the intended purpose and the company's required demonstration for each criterion.

It is in light of the three criteria discussed below that the AUC will determine whether or not a capital project qualifies for capital tracking under the 'K-Factor' of the PBR formula. Accordingly, Alberta Utilities were directed to include in their capital tracker proposals,

[17] Ibid., paragraph 535
[18] Ibid., paragraph 518
[19] Ibid., 524
[20] Ibid., paragraph 535

compelling supporting documentation from engineering studies and other relevant sources that support their claim and proposed level of capital expenditure required.

Table 1: AUC Capital Tracker Criteria, Purpose, and Company Required Demonstration[21]

Criteria	Intended Purpose	Required Demonstration
1. The project must be outside of the normal course of the company's ongoing operations	• To avoid double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X Mechanism • To ensure capital tracker projects are of sufficient importance that the company's ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken	• Demonstrate that Capex are required to prevent deterioration in service quality and safety • Demonstrate that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historical levels • Demonstrate that capital project could not have been undertaken in the past as part of a prudent maintenance program
2. Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party	• To limit the scope of eligible capital projects to only those required for replacement of aged infrastructure and those required by 3rd parties	• If project proposed in tracker is externally driven, the company must demonstrate that such costs are significantly different than historical trends
3. The project must have a material effect on the Company's finances	• To limit the use of capital tracker by excluding strings of unrelated small projects that may have the appearance of being atypical on its own but are in the normal course of operation when taken together	• Demonstrate the materiality of the project

In addition to the factors discussed above, the AUC made determinations on the following PBR components.

Earning Sharing Mechanism ("ESM")

Although some Alberta Utilities proposed an ESM in their PBR proposals, the AUC opted to exclude an ESM from the Alberta Model. It was determined that an ESM will provide

[21] Ibid., paragraph 594 - 601

disincentives that are inconsistent with the objectives of PBR[22] and may result in greater regulatory burden[23]. In particular, the AUC:

1. Agreed with expert testimony that ESMs may incentivize cost misreporting and cost shifting while blunting the efficiency incentives of PBR with regard to managerial effort, since the firm bears the costs of its effort at reducing costs but only retains a share of the savings[24];
2. Agreed with Interveners that the annual review of the earning sharing would likely require greater regulatory burden over time[25].
3. Believed that the ESM may either deprive the company of a reasonable opportunity to earn its approved ROE or result in higher than necessary rates to give the company a reasonable opportunity to earn its approved ROE, resulting from volatile earnings that may or may not trigger the sharing of profits or shortfalls[26].

For the reasons discussed above, the AUC determined that "the safeguards offered by an ESM do not outweigh the negative efficiency incentives that would be re-introduced into the PBR plan as a result of the Incorporation of an ESM."[27] As such, ESMs were not included in the Alberta PBR model.

Off-Ramps and Re-Openers

With respect to PBR Re-Openers, which serve as safeguards against unexpected results during the PBR period that allow for the re-evaluation and modification of certain aspects of the PBR plan, the AUC approved four eligible 'reopening' scenarios. Each scenario is described in Table 2 below.

[22] Ibid., paragraph 821
[23] Ibid., paragraph 818
[24] Ibid., paragraph 816
[25] Ibid., paragraph 817
[26] Ibid., paragraph 821
[27] Ibid., paragraph 818

Table 2: AUC Re-Opener Scenarios

Re-Opener Scenario	Description
Material change in ROE[28]	Threshold for re-opening: +/- 500 basis points in any given year +/- 300 basis points in any given 2 consecutive years Calculation: • Based on approved generic ROE for the year(s) in which the need for a re-opener is to be considered • ROE is to be weather normalized • To be calculated in the same way as the ROE reported in the company's annual AUC Rule 005 filings.
Material contraction or expansion in the service territories or customers[29]	Materiality: To be determined on a case-by-case basis since it will vary from company to company over time
Change in default supply regulation, or regulatory direction with respect to the assumption of default supply obligation[30]	For circumstances that cannot be dealt with through Z-factor treatment or other mechanisms, an application to the Commission to re-open the PBR will be accepted
Substantial Change in Circumstance[31]	For circumstances that do not qualify for Z-Factor treatment, an application to the Commission to re-open the PBR will be accepted.

Efficiency Carry-Over Mechanism ("ECM")

In Alberta, the AUC regarded ECMs as "an innovative mechanism [with] incentive properties [that] encourage companies to continue to make cost saving investments near the end of the PBR term"[32]. Accordingly, the AUC approved an ROE ECM that would apply for two years after the end of the PBR plan, calculated as follows:[33]

$$\left[\frac{(Average\ Achieved\ ROE - Average\ Approved\ ROE)}{2}\right] \times 50\%$$

[28] Ibid., paragraph 737 - 739
[29] Ibid., paragraph 740 - 741
[30] Ibid., paragraph 742
[31] Ibid., paragraph 752 - 753
[32] Ibid., paragraph 775
[33] Ibid., paragraph 766, 776

The ROE ECM applied to the average approved generic ROE in place for each year during the PBR and included an upper limit which can be carried over to a maximum of +0.5 per cent[34]. The Alberta Utilities' were directed to calculate their actual ROE in the same way as the ROE reported in the companies' annual AUC Rule 005 filings. Provisions to carry over under earnings were not approved.

Capital Re-Basing

The AUC rejected the annual re-basing of companies' capital expenditure.

Service Quality Indicators

With respect to service quality indicators for PBR, the AUC decided to continue to use AUC Rule 002, which sets out quarterly and annual service quality reporting requirements for electric and gas distributors. In addition to the existing metrics under AUC Rule 002, the AUC proposed to establish defined targets where none currently exists and to introduce an enforcement mechanism for penalties when service quality targets are not met.

[34] Ibid., paragraph 779

Ontario's 4th Generation IR for Electric Distributors

HISTORY AND DEVELOPMENT

The Ontario Energy Board (OEB or Board) regulates 77 power utilities that operate Ontario's electricity distribution networks. Since the year 2000 the Board has established 4 generations of incentive regulation. The current 3rd generation IR will be finished by the end of 2013 and the new 4th generation IRs will be implemented based on the regulatory framework that was laid out in OEB's October 18, 2012 report "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach ("RRFE")."[35] While most of the components of 4th generation IR are already decided, there are a couple of elements that will be determined in upcoming decisions. For these items, the 3rd generation IR data has been used in this summary.

The dissimilarities between Ontario's 77 power utilities in terms of size, asset age and sustainment policies, number and type of customers are significant and limit the Board's ability to prescribe "one size fits all" kind of a regulatory framework. As a solution, the Board has decided to implement a menu approach for utilities rate-setting where a utility may choose from three sets of options:

1. 4th generation incentive rate-setting (Suitable for the majority of distributors where a distributor anticipates that some incremental investment needs may arise during the term)
2. Custom incentive rate-setting (Suitable for distributors with large or highly variable capital requirements)
3. Annual incentive rate-setting index (Suitable for distributors with limited incremental capital requirement)

In the following sections the components of each of these options will be investigated.

DESIGN AND COMPONENTS OF THE PBR MODEL

Going-In Rates

Under the 4th generation IR, going-in rates are set on a single forward test-year cost of service basis. This use of a cost of service test year is a common form of setting the year-zero rates. The Custom IR Option is designed to fit the specific applicant's circumstances and is most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The going-in rates in this method are determined in a multi-year application review where the distributor is expected to file robust evidence of its cost and revenue forecasts over the IR term, as well as detailed infrastructure investment plans over that same time frame.

[35] http://www.ontarioenergyboard.ca/OEB/_Documents/Documents/Report_Renewed_Regulatory_Framework_RRFE_20121018.pdf

Under the Annual IR Index Option, initial rates are set by applying the annual adjustment formula to existing rates and therefore no forecast cost of service review is required. Table 3 below summarizes these three going-in rate options.

Table 3: Menu of Options for Going-In Rates in OEB's New Regulatory Framework

4th Generation IR	Custom IR	Annual IR Index
Determined in single forward test year cost of service review	Determined in multi-year application review	No cost of service review - existing rates adjusted by the annual adjustment mechanism

Form of the PBR Formula

In both 4th generation IR and annual IR index options the rates are indexed by the price cap index formula while in custom IR approach the allowed rate of change in the rate over the term will be determined by the OEB on a case-by-case basis informed by empirical evidence including the distributor's forecasts, the Board's inflation and productivity analyses and benchmarking to assess the reasonableness of distributor forecasts.

The OEB continues to support a comprehensive approach to rate setting in all three options, stating that the due to the interrelationship between capital expenditures and OM&A expenditures, a total expenditure approach creates stronger and more balanced incentives for efficiency.

Length of Term

Following the experience of the 3rd generation IR, the term of 4th generation IR was increased by one year to 5 years (one year rebasing plus 4 years). The Board asserted that the longer term will strengthen efficiency incentives, support innovation and help manage the pace of rate increases for customers.

The custom IR option term was also set to a minimum of 5 years. The OEB decision articulated that the minimum of 5 years is necessary as custom IR approach will require the allocation of significant resources from both the Board and utilities.

Given the nature of rate adjustment in annual IR index methodology, the annual IR approach does not have any fixed price control period and the distributor may apply to rebase its rates and set them under 4th generation or custom IR approaches at any time.

Inflation (I-Factor)

Under the 3rd generation IR, the inflation was measured based on GDP IPI FDD[36] index. However under new regulatory framework the OEB concluded that it will be appropriate to adopt a more industry specific inflation factor. The new inflation index will be a composite index that includes a non-labor prices element (indexed by Ontario-specific distribution industry

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[36] Gross Domestic Product Implicit Price Index Final Domestic Demand

indices) and a labor prices element (indexed by an appropriate generic and non-distribution industry-specific index). The final decision on the appropriate non-labor and labor price indices and their relative weighting in the composite index is due for mid-2013.

Productivity Improvement Factor (X-Factor)

Under the 3rd generation IR, the OEB decided that due to the lack of a comprehensive Canadian (or Ontario) utilities' financial and operational database, the data from U.S. peer group companies may be used to measure TFP. The OEB's consultant used the U.S. data for a period of 1988-2006 and calculated a productivity factor of 0.72 percent, which was approved in the OEB's supplemental report[37] in September 2008 as the productivity factor for 3rd generation IR. The Board also concluded that there are considerable variances between existing efficiency cultures of the utilities and that a single stretch factor for all distributors is not appropriate. Therefore, two benchmarking evaluations[38] were considered to divide the Ontario's power distributors to three efficiency "cohorts" where each cohort was given a specific stretch factor. While grouping of distributors into three cohorts was based on solid benchmarking techniques, the determination of stretch factors values was mainly subjective and based on the OEB's judgment. Table 4 below presents the characteristics of each cohort and their respective stretch factor value.

Table 4: Stretch Factor Values and Criteria for Three Efficiency Cohorts

Characteristic	Cohort One	Cohort Two	Cohort Three
Criteria for cohort groups	Statistically superior econometric benchmark and (2) top quartile result in the unit cost index benchmark	Superior in one methodology and inferior in the other one	Inferior in both benchmarking techniques
Stretch factor value	0.2	0.4	0.6

Under the 4th generation IR the X-factor for individual distributors will continue to consist of an empirically derived industry productivity trend (productivity factor) and a stretch factor, but will be based on Ontario TFP trends[39] instead of U.S. data. The values for the productivity factor and stretch factor are not yet determined although a study has been filed and a decision for outstanding issues is due for mid-2013.

[37] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Supp_Report_3rdGen_20080917.pdf
[38] (1) Econometric benchmarking and (2) a Unit cost index benchmark
[39] Based on the data sets gathered under Ontario's Reporting and Record Keeping Requirement (Triple R).

Z-Factor

The OEB's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd generation Incentive Regulation,[40] will continue under all three menu options. Under this framework, a materiality threshold based on the distributor's revenue requirement is set to provide the distributors with guidance as to whether or not they should be applying to the OEB for relief from a Z-factor event. However, Ontario's utilities have considerable differences in terms of the size of revenue requirement and using a single threshold criterion is not appropriate. The materiality threshold is differentiated based on the relative magnitude of the revenue requirement. Specifically, the materiality threshold is presented in Table 5 below:

Table 5: Z-Factor Materiality Threshold Relative to the Size of Distributor's Required Revenue

Size of Revenue Requirement	Materiality Threshold
Less than or equal to $10 million	$50 thousand
Greater than $10 million and less than or equal to $200 million	0.5% of distribution revenue requirement
More than $200 million.	$1 million

Y-Factor (Deferral and Variance Accounts)

All three menu options include some deferral and variance accounts that are treated outside the incentive formula with some minor differences. These include both commodity and non-commodity related deferral accounts however the details of deferral and variance accounts are out of scope of this report.

K-Factor

Under the OEB's new regulatory framework, the annual IR index and custom IR approaches may not include any capital expenditure outside the rate adjustment formula. The 4th generation IR is the only menu option that includes the Incremental Capital Module ("ICM") where the utility may ask for capital spending outside the incentive formula according to a pre-defined set of criteria and recovers its costs prior to rebasing. These eligibility criteria for the ICM are as follows:

1. Materiality threshold: The amounts must have a significant influence on the operation of the distributor
2. Need: The amounts must be clearly outside of the base upon which rates were derived.
3. Prudence: The distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

[40] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2007-0673/Report_of_the_Board_3rd_generation_20080715.pdf

Earning Sharing Mechanism

Following its policy in 3rd generation incentive regulation, the OEB's new regulatory framework does not include an earnings sharing mechanism.

Safeguard Mechanism (Off-Ramps and Re-Openers)

Under the regulatory framework, each rate-setting method will include a trigger mechanism with an annual ROE dead band of ±300 basis points. When a distributor performs outside of this earnings dead band, a regulatory review may be initiated.

In addition to the mentioned trigger mechanism a utility may request an early termination and seek to have its rates rebased if it can convince the OEB that early rebasing is necessary.

Efficiency Carry-Over Mechanism

The 3rd generation IR did not include any post-term carry-over of efficiency savings however the OEB's report on new regulatory framework recognizes that additional regulatory mechanisms may be necessary to achieve efficiency objectives and states that the OEB will engage stakeholders in further consultation on establishment of an "efficiency carry-over mechanism" in due course.

Capital Re-Basing

The OEB rejected the annual re-basing of companies' capital expenditure.

Service Quality Indicators

The 3rd generation incentive regulation included seven service quality indicators (connection of new services, appointments met, telephone accessibility, written response to enquiries, appointment scheduling, rescheduling a missed appointment and telephone call abandon rate) and three service reliability indicators (SAIFI, SAIDI, and CAIDI).

The renewed regulatory framework includes a more comprehensive set of performance outcomes. In addition, as a new regulatory tool for performance monitoring and distributor benchmarking, the Board will use a scorecard approach to link directly to the performance outcomes. The new scorecard design will include four performance areas as presented in Table 6 below.

Table 6: Performance Areas in Electricity Distributor Scorecard

Performance Area	Description
Customer focus	Services are provided according to identified customer preferences
Operational effectiveness	Continuous improvement in productivity and cost performance is achieved; utilities deliver on system reliability and quality objectives;
Public policy responsiveness	Utilities deliver on obligations mandated by government
Financial performance	Financial viability is maintained; savings from operational effectiveness are sustainable

The details of key performance indicators in each of these performance areas and their respective targets for PBR term are not yet finalized. A decision from the OEB is expected in mid-2013.

Ontario's IR for Enbridge Gas Distribution

EGD made the first application to the OEB for PBR, a three-year plan in 1999 targeted on O&M costs. Since the end of its PBR plan in 2002, EGD's rate applications have been based on a cost of service basis[41] with three rate cases filed during the 2005-2007 period. In 2005, the OEB's Natural Gas Forum ("NGF") report established three criteria for design of future multi-year incentive regulation:

1. Establish incentives for sustainable efficiency improvements that benefit customers and shareholders;
2. Ensure appropriate quality of service for customers; and
3. Create an environment that is conducive to investment.

On May 3, 2007 the OEB expressed its intention to implement a multi-year incentive ratemaking framework for 2008 and requested that the EGD file a PBR application based on NGF criteria.

EGD filed an Application on May 11, 2007 for an order of the Ontario Energy Board (OEB) approving or fixing rates for the distribution, transmission and storage of natural gas. On January 29, 2008 Enbridge filed a Settlement Agreement in this matter. After the review of submissions on the EGD settlement by the Board, EGD filed a revised comprehensive Settlement Agreement. On February 11, 2008 the Board approved the revised agreement stating that the agreed settlement is in public interest and satisfies all the NGF criteria. Currently EGD is rebasing its rate base under a cost of service plan.

DESIGN AND COMPONENTS OF THE PBR MODEL

Going-In Rates

In the first year of the plan, new rates were established based on the outcome of a cost of service proceeding by EGD.

Form of the PBR formula

EGD's 2008 IR plan was primarily applied to regulated gas delivery revenues per customer and calculated based on following formula:

$$DRR_t = \left(\frac{DRR_{t-1} - (Y_{t-1} + Z_{t-1})}{C_{t-1}}\right) * (1 + P * INF) * C_t + Y_t + Z_t$$

Where:

[41] Except for 2004 which was an application for a rate index plan based on 90% of the forecast rate of inflation.

- DRR = the distribution revenue requirement
- t = the rate year
- C = the average number of customers
- P = the inflation coefficient
- INF = the inflation index
- Y = pass through at cost of service
- Z = exogenous factors

The revenue per customer cap methodology incorporates the forecast impact of changes in average use on an annual forecast basis.

Length of Term

Following the experience of previous IR plans in Ontario (including EGD's previous 3-year IR plan), and in order to reduce the number of rate cases, the plan term was increased to 5 years.

The parties to the proceeding also agreed that a consultation between EGD and the parties may be convened, at the request of EGD, in year four (4) of the term of the IR Plan in order to discuss and consider whether an extension of the IR Plan for up to two additional years is warranted.

Inflation (I-Factor)

Canada's Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP IPI FDD") was chosen as the index formula inflation factor, and was measured as the annualized average of the index for four quarters, from Q2 of the previous year to Q2 of the year in which the proposed rate change was filed.

Productivity Improvement Factor (X-Factor)

Evidence on this issue was filed by five experts, most of whom did not share the views or conclusions of the others. There were also differences among the positions advanced by many of the Parties and some Parties took no position at all on this issue. The Parties were unable to agree on the appropriate X factor for inclusion in EGD's revenue per customer cap IR framework. As an alternative to an X factor, the Parties agreed on an inflation coefficient, the effect of which is to adjust annual distribution revenues by a percentage of the annual rate of inflation (by multiplying the annual rate of inflation by the inflation coefficient). The Parties agreed that for each year of the IR Plan, the Inflation Coefficient and implied X-Factor shall be as follows:

- 0.60 for 2008 (Implied X-factor of 0.40%)
- 0.55 for 2009 (Implied X-factor of 0.45%)
- 0.55 for 2010 (Implied X-factor of 0.45%)
- 0.50 for 2011 (Implied X-factor of 0.50%)
- 0.45 for 2012 (Implied X-factor of 0.55%)

Z-Factor

EGD's Z-Factor was defined to recover the cost of non-routine events that were not otherwise recovered in the annual adjustment mechanism. The following criteria were set by the Board for costs to be eligible for Z-Factor recovery:

- The event must be causally related to an increase or decrease in the distributor's cost
- The cost increase/decrease must be beyond the control of the Company management and not a risk a prudent utility could mitigate
- The cost increase/decrease must not be otherwise reflected in the annual rate adjustment mechanism
- The cost increase/decrease must be prudently incurred
- The amount of the cost increase/decrease, for the sum of all individual events reflected in an annual Z factor filing, must be greater than the materiality threshold of $1.5 million.

Y-Factor (Deferral and Variance Accounts)

EGD's IR plan included a Y-Factor to recover the routine, or expected, cost changes that are outside the scope of the annual adjustment mechanism. EGD filed for Y-Factor adjustments at the same time it filed for rate adjustments under the annual adjustment mechanism. The costs treated under EGD's Y-Factor included items such as DSM program costs, upstream gas commodity costs, upstream transportation, storage and supply mix costs, changes in the embedded carrying cost of gas in storage and working cash related to changes in gas costs and etc.

K-Factor

EGD's IR plan did not include any mechanism for extraordinary capital projects. An incremental capital module was introduced only for power distributors.

Earning Sharing Mechanism

Under EGD's 2008-2012 IR plan, all parties agreed on an asymmetric earnings sharing mechanism with a 100 basis point dead band. The sharing amount was calculated as follows:

> If in any calendar year, actual weather normalized ROE was more than 100 basis points over the Board's approved ROE, then the resultant amount shall be shared equally (i.e.,50/50) between EGD and its ratepayers.

Safeguard Mechanism (Off-Ramps and Re-Openers)

EGD's IR plan incorporated an earning-based off-ramp provision. The Parties agreed that if, in any year of the IR Plan, there was a 300 basis point or greater variance in weather normalized utility earnings, above or below the amount calculated annually by the application of the ROE Formula, EGD shall file an application with the Board, with appropriate supporting evidence, for a review of the adjustment formula. The Parties also agreed that this review will be prospective only (i.e., will not result in any confiscation of earnings). It was determined that during the course of that review, the OEB may be asked to determine whether the application of the IR Plan, including the adjustment formula, should continue and, if so, with or without modifications.

Efficiency Carry-Over Mechanism

EGD's multi-year IR plan did not include any specific efficiency carry-over mechanism.

Capital Re-Basing

The OEB rejected the annual re-basing of companies' capital expenditure.

Service Quality Indicators

The OEB implemented Service Quality Requirements ("SQRs") prior to the establishment of the IR plans. The SQRs were treated outside of the IR plans. The following is the list of approved SQRs:

- Answer at least 75% of customer telephone calls to the utility phone center within 30 seconds.
- Have an abandoned call rate (where the customer hangs up before speaking to a customer service representative) of no more than 10%.
- Have a verifiable quality assurance program in place to audit and ensure billing accuracy.
- Have no more than 0.5% of meters go four consecutive months without being read.
- Meet at least 85% of scheduled service appointments within a four hour window around the scheduled appointment time.
- Reschedule 100% of missed appointments within two hours of the end of the original appointment time.
- Respond to at least 90% of gas emergency calls within one hour.
- Respond to at least 80% of written complaints within 10 days.
- Reconnect at least 85% of customers who have been disconnected within two days after they have resolved payment problems.

Ontario's IR for Union Gas Limited

HISTORY AND DEVELOPMENT

Union and EGD's 2008-2012 IR plans are homogenous in many aspects. Similar to EGD, Union filed its application for multi-year incentive rate mechanism on May 11, 2007 after the OEB identified its intention to implement rates under a multi-year ratemaking framework based on NGF report criteria. Union filed Settlement agreements which addressed most of the components of an incentive regulation plan (dated January 14, 2008). Consequently, the OEB, by decision dated January 17, 2008, accepted the Union settlement agreement.

DESIGN AND COMPONENTS OF THE PBR MODEL

Going-In Rates

Union's 2007 rates (which were based on a cost of service application) were used as base rates for incentive rates mechanism.

Form of the PBR Formula

One intended difference between the EGD and Union settlement was that the Union IR plan was described as a price cap plan and therefore was applied to the adjustment of gas delivery prices. The parties agreed that the structure of the price cap index should be as follows:

$$PCI = (I-X) + Y + Z + AU$$

Where:

- PCI = Price cap index
- I = Inflation index
- X = Productivity factor
- Y = Pre-determined pass-through
- Z = certain non-routine adjustments
- AU = Average use

In practice, the adoption of average use in PCI formula transformed the price cap index into a revenue adjustment formula. The average use was used to reflect the impact of changes in Average Use Per Customer ("AUPC") on a class by class basis. For each rate class, the AU adjustment was calculated by adjusting the volume used to determine rates by the average of the three most recent years' actual weather normalized change in volumes per general service customer within that rate class.

The AU factor adjusts the volumetric charges of the affected rate schedules to reflect the measured change in average gas use for customers in that particular rate class. If average use for customers on the rate declines, volumetric charges are increased proportionately to recover revenue losses associated with the measured decline in AUPC. An increase in average use for customers on the rate would lead to an analogous decline in the tariff's volumetric charges.

Length of Term

Similar to EGD's plan, Union's IR plan was designed for 5 years (2008-2012).

Inflation (I-Factor)

Similar to EGD's plan, the inflation factor was determined as Canada's GDP IPI FDD.

Productivity Improvement Factor (X-Factor)

Union's X-Factor (inclusive of any stretch factor) was fixed at 1.82% for the term of the IR plan. This value was not based on any specific TFP calculation however the agreed value fell within a range of X-Factor values presented by various expert witnesses in the proceedings (Union initially proposed an X-Factor of 0.02%).

Z-Factor

The eligibility criteria for considering Z-factor in incentive rate mechanism were the same in Union's and EGD's IR plans.

Y-Factor (Deferral and Variance Accounts)

Under Union's IR plan, the following items were treated as elements of the Y-Factor:

- Upstream gas costs
- Upstream transportation costs
- Incremental DSM costs and volume reductions
- Storage margin sharing changes

The parties also agreed that the majority of deferral accounts would continue during Union's IR plan.

K-Factor

Union's IR plan did not include any specific capital module outside the price cap formula.

Earning Sharing Mechanism

Union's ESM was based on the difference between actual and approved ROE (resulting from the Board's approved ROE formula), and initially any difference between actual ROE and approved ROE formula plus 200 basis points was shared 50/50 between customers and shareholders. Union's ESM was modified after the first year of its IR plan (2008) so that whenever actual ROE exceeded approved ROE by 300 basis points, the difference is shared 90/10 between customers and shareholders.

Safeguard Mechanism (Off-Ramps and Re-Openers)

Originally Union's IR plan included an off-ramp provision. The provision specified that whenever weather normalized ROE was at least 300 basis points above or below the approved ROE, the Company would file an application with the Board for a review of the IR mechanism. In 2008, however, Union's actual ROE exceeded approved ROE by 330 basis points. This led to the elimination of Union's off-ramp provision, as well as the modification of the ESM to allow for earnings to be shared 90/10 when Union's actual ROE exceeded the approved ROE by 300 or more basis points.

Efficiency Carry-Over Mechanism

Similar to EGD's IR plan, there was no efficiency carry-over mechanism under Union's IR plan.

Capital Re-Basing

The OEB rejected the annual re-basing of companies' capital expenditure.

Service Quality Indicators

Union's group of service quality indicators were identical to EGD's SQIs and were treated outside the IR plan.

Past PBR Plans of FortisBC Inc. (Electric)

HISTORY AND DEVELOPMENT

FBC has recently reverted back to a COS methodology after operating under PBR mechanisms from 1996 to 2004 and again from 2007-2011. The latter term, originally approved for 2007 and 2008, was extended for an additional 3 years, ending in 2011. The most recent PBR improved upon the Company's previous PBR Plan which was considered by stakeholders to be complicated, lacking in transparency and occasionally leading to results that unfairly benefited or penalized either shareholders or ratepayers. FBC addressed this concern by calculating an incentive based on the Company's overall financial performance in relation to the allowed ROE. The most recent PBR also expanded the number and range of non-financial performance standards.

DESIGN AND COMPONENTS OF THE PBR MODEL

Going-In Rates

The 2006 Revenue Requirements formed the base year for FBC's 2007-2009 PBR Plan, and was therefore reviewed in detail by the Commission and registered Interveners. FBC filed an Application on November 24, 2005 for its 2006 Revenue Requirements and for a multi-year PBR for the period 2007-2009.

Following the submission of Information Requests by Interveners and responses by the company, a Negotiated Settlement Process ("NSP") commenced on April 18, 2006. FBC and the group of Interveners concluded negotiations on April 19, 2006. The negotiations resulted in a settlement agreement regarding the terms of both the 2006 Revenue Requirements, and the 2007-2009 PBR Plan.

Form of the PBR Formula

The PBR mechanism proposed for the 2007-2009 PBR was a hybrid form of PBR methodology. During the term of the PBR, the Gross O&M expenses, before capitalized overheads were set annually by the formula. The formula incorporated a Growth Escalator (customer growth) and an Inflation Factor (the Consumer Price Index for British Columbia), minus an agreed Productivity Improvement Factor ("PIF").

Capitalized overheads were also determined annually by formula, at 20% of Gross O&M expense. The Capital Structure and Return on Equity as determined by a separate Commission process, was to apply for the term of the PBR. All capital expenditures were tested in a separate process. All other cost accounts were re-forecast at the Annual Review.

An Annual Review and Negotiated Settlement process was proposed for this PBR to allow stakeholders the opportunity to review and provide input to the Revenue Requirements by means of Information Requests and workshop processes. The Company filed a Revenue Requirements Application each year to set rates for the subsequent year. The Application was followed by a workshop that was held in conjunction with the Annual Review, and was followed by a Negotiated Settlement Process. This process provided an opportunity for FBC to explain/justify its forecasts.

Length of Term

The proposed term of the PBR agreement was for a three year period, from 2007-2009. The Commission accepted the 2007-2008 term, however the determination of whether to include the year 2009 was subject to agreement from all stakeholders. The Company and all stakeholders were to review the PBR mechanism at the Company's 2008 Annual Review. At that time, the Company and stakeholders would determine whether or not to extend the PBR to 2009.

Stakeholders from FBC's 2006 PBR Settlement Agreement were invited to negotiate the extension of the PBR Agreement. An agreement was reached between the parties to extend the PBR Settlement from 2009 to 2011. The terms of the PBR generally remained the same as those of the 2006-2007 PBR Agreement.

Inflation (I-Factor)

The British Columbia Consumer Price Index ("CPI") was accepted as the cost escalator. The forecast used was the average of the most recent forecasts from the Conference Board of Canada, the BC Ministry of Finance, the RBC Financial Group and the Toronto-Dominion Bank.

Productivity Improvement Factor (X-Factor)

The following productivity improvement factors were agreed to for the full term of the PBR Agreement:

- 2% for 2007
- 2% for 2008
- 3% for 2009
- 1.5% for 2010
- 1.5% for 2011

In addition, for 2010 and 2011, if the CPI were to exceed 3% in any year, the excess would be added to the productivity factor, effectively capping the CPI at 3%.

Z-Factor

Certain "extraordinary" items were to be handled outside of the ROE sharing mechanism. This would have included, for example, a situation where FBC may have proposed initiatives for mutually beneficial items where investment recovery would have exceed the term of the PBR. Such a mechanism would have provided an incentive to undertake projects which would not otherwise have returned a benefit because of the limited term of the PBR. No such items arose during the PBR term.

The ROE adjustment mechanism replaced all of the previously-existing mechanisms, including the O&M Incentive Sharing Mechanism, the power purchase Sharing Mechanism and other flow-through provisions. The elimination of the "flow-through" accounts, in particular, allowed the Company to earn a greater incentive for pursuing savings for "quasi-controllable" costs, such as property taxes.

A Z-Factor was also proposed in FBC's PBR to allow for recovery or refund of certain extraordinary costs that fall outside of the normal course of operations as determined by the formula for base O&M expenses. These items were typically outside of FBC's control, including:

FBC proposes that the circumstances be limited to:

1. Directives of the BCUC or other competent regulatory agencies,
2. Acts of legislation or regulation of government,
3. Changes due to Generally Accepted Accounting Principles,
4. Changes due to actuarial evaluations,
5. Force Majeure events,
6. Other extraordinary events as agreed to by the parties in the Negotiated Settlement Process.

FBC endeavored to include these items in the Revenue Requirements where possible. In unforeseen circumstances, these items were to be captured in a deferral account for consideration and disposition as part of the Annual Review.

Y-Factor (Deferral and Variance Accounts)

Various deferral accounts were proposed for this PBR. These included existing deferral accounts for ongoing application and hearing costs, as well as new deferral accounts for unanticipated projects, as described in the Z-factor discussion above.

K-Factor

FBC's capital expenditures were reviewed either annually or semi-annually as part of the Capital Expenditure Plan. The capital expenditures were approved, subject to certain CPCN applications for major projects, as directed by the Commission. The amount of net addition to rate base, along with the AFUDC calculation, was examined at the Revenue Requirements workshop, and approved as part of the Revenue Requirements approval by Commission order subsequent to the workshop and NSP.

Earning Sharing Mechanism

The mechanism utilized by FBC is referred to as a "collared ROE" whereby customers and shareholders share differences between the allowed earnings, set by the Commissions automatic adjustment mechanism, and the actual realized earnings. The collared ROE mechanism was intended to calculate a true incentive based on overall financial performance compared to the Company's allowed earnings.

Within a range of 2% above or below the allowed ROE, customers and shareholders shared equally any positive or negative earnings variance, adjusted for income tax. Differences greater than the 2% threshold were to be placed in a deferral account and reviewed at a subsequent Annual Review.

Safeguard Mechanism (Off-Ramps and Re-Openers)

FBC did not propose any off-ramps or re-openers for any of the components of the PBR. Instead, the Company proposed that any items that fell outside of the approved threshold would be reviewed at the Annual Review. At that time, FBC or its shareholders would have the right to request a review of the mechanism.

Efficiency Carry-Over Mechanism

FBC's PBR did not contain an end of term efficiency carryover mechanism. Capital expenditures were reviewed under a separate process, as part of the annual Capital Expenditure Plan. O&M was not subject to an end of term efficiency carryover mechanism.

Capital Re-Basing

Capital expenditures were reviewed under a separate process, as part of the annual Capital Expenditure Plan, therefore, capital re-basing was not a consideration as a part of FBC's PBR.

Service Quality Indicators

Performance Standards for the term of the PBR were implemented in the areas of System Reliability, Generator Reliability, Customer Service, and Employee Health and Safety.

If FBC earned ROE in excess of the allowed level, its eligibility for an incentive under the sharing system was determined following a review of its annual performance. In order to be eligible for an incentive, FBC had to show that the additional earnings were not achieved as a direct result of deteriorated performance. In addition, although targets for each performance standard were set, the failure to meet any or all performance target did not necessarily mean the incentive payment would be disallowed.

Performance standards were set at the beginning of the test year and reviewed at the Annual Review. At that time, FBC would report on the status of its performance standards.

Past PBR Plans of FEU (Gas)

HISTORY AND DEVELOPMENT

During the last two decades, FortisBC Energy (FEI) has operated under a PBR mechanism for two periods: 1998-2001 and 2004-2009. The first PBR plan was approved by the Commission for the period 1998-2000, and later extended to include 2001. The second PBR plan was originally approved from 2004-2007, and subsequently extended for two years, ending in 2009.

The details of the most recent PBR plan are discussed in the following sections.

DESIGN AND COMPONENTS OF THE PBR MODEL

Going-In Rates

The PBR also involved applying a formula to both O&M and capital expenditures. The approved 2003 numbers, adjusted for customer growth, inflation and a productivity factor constituted the base figures for the 2004 PBR plan.

Form of the PBR Formula

The PBR mechanism employed was a hybrid form of PBR methodology. Both O&M expenses and capital expenditures were determined based on a formula. The formula adjusted base rates for the forecast inflation rates, changes in customer numbers and a productivity improvement factor that was calculated as a percentage of the forecast inflation rate.

An Annual Review, as well as a Mid-term Assessment Review was conducted for the PBR. The Annual Review provided an opportunity for all parties involved with the PBR to remain up-to-date on FEI's performance during the previous year, as well as to learn of anticipated performance for the upcoming year.

The Mid-term Assessment Review was to be held prior to the end of the third year of the 2004 PBR, or at the end of 2006. The purpose of the Mid-term review was to ensure that each element of the PBR was functioning the way it was intended to. In the event that the PBR was resulting in a deterioration of service quality, or creating financial distress for FEI, the parties would work out a plan to remedy the issues.

Length of Term

In its PBR application, FEI proposed a five year term, from 2004 to 2008. During the Negotiation Settlement Process, a four year PBR term was agreed to, from 2004 to 2007. In 2007, FEI filed an application requesting a two year extension of the PBR. The extension was approved, and the PBR was extended to the end of 2009.

The terms of the PBR extensions generally remained the same as those of the original PBR Agreements.

Inflation (I-Factor)

FEI's PBR used a weighted average of inflation forecasts from the following sources to determine the annual forecast inflation rate: the Toronto-Dominion Bank, the Royal Bank of Canada, the British Columbia Ministry of Finance and the Conference Board of Canada.

Productivity Improvement Factor (X-Factor)

The following productivity improvement factors were agreed to for the term of the 2004 PBR Agreement:

- 50% of CPI for 2004 and 2005
- 66% of CPI for 2006 to 2009

Each year during the Annual Review, an updated forecast of inflation was provided for the upcoming year.

Z-Factor

There are a number of factors that are out of a utility's control, but directly impact the utility's operations. FEI identified a number of these exogenous factors, including:

- Judicial, legislative and administrative changes
- BCUC Orders or Decisions
- Catastrophic events, bypass or similar events
- Major seismic incidents
- Acts of war, terrorism or violence
- Changes in Generally Accepted Accounting Principles, Standards and Policies
- Changes in Revenue Requirements due to BCUC Decisions

FEI flowed through adjustments to rates, both positive and negative, resulting from impacts associated with the factors listed above. Any factors that were partially controllable were to be evaluated on an item by item basis, and considered in the context of the overall PBR.

Y-Factor (Deferral and Variance Accounts)

FEI employed the use of deferral accounts, flow-through and Annual Reviews for those items over which FEI had little or no control. The continuation of existing deferral accounts, as well as their corresponding amortization periods was implemented.

K-Factor

Capital expenditure projects over the $5 million threshold were excluded from the capital formula, and instead CPCN applications were filed for these capital projects. Once a CPCN application was approved, the capital cost, including AFUDC, was added to rate base in the year following completion of the capital project.

Earning Sharing Mechanism

FEI shared both earnings and losses equally with customers during the term of its PBR plan. This is commonly known as a 50/50 earnings sharing mechanism. The earnings (or losses) are calculated as the difference between FEI's formulaic and allowed earnings in each year of the PBR.

The 2004 PBR also attached a trigger mechanism to the earnings sharing mechanism. The trigger mechanism allowed any party to request a Commission review of the PBR if the achieved ROE after earnings sharing varied from the allowed ROE by 150 points during any year of the PBR term.

Safeguard Mechanism (Off-Ramps and Re-Openers)

FEI's PBR plan did not include off-ramp mechanisms throughout the term of the PBR. The trigger mechanism discussed above allowed any party the right to request a review of the earnings sharing mechanism if the difference between the allowed and achieved ROE exceeded 150 basis points.

Efficiency Carry-Over Mechanism

In its PBR plan, FEI proposed a Full Term Efficiency Incentive ("FTEI"). The FTEI would allow for the continued retention of savings efficiencies for a period of five years beyond the end of the PBR.

The Commission did not allow the FTEI, but instead approved a capital benefits phase out. This involved determining the cumulative difference over the term of the PBR between the formulaic and actual capital expenditures. Two thirds of this amount was then phased out in the year following the end of the PBR plan, and the remaining one third was phased out in the second year following the end of the PBR term.

Capital Re-Basing

Rebasing did not occur during the term of the PBR. Instead, the results of the PBR plan were presented at the Annual Review, along with a revised forecast of a number of factors including inflation, revenue and customer additions.

Service Quality Indicators

FEI relied on a number of service quality indicators to ensure that service quality did not deteriorate throughout the term of both PBRs. The PBR service quality indicators include:

1. Response time to site from time of dispatch for emergency calls;
2. Percent of responses within 30 seconds by a person for an emergency call;
3. Percent of responses within 30 seconds by a person for a non- emergency call;
4. Transmission system annual reportable incidents;
5. Percent of customer bills produced meeting performance criteria;
6. Percent of transportation customer bills accurate;
7. Percent of meter exchange appointments met;
8. Percent of time when transportation meter measurement first report deviates less than 10% when compared to billable amount;
9. Independent customer satisfaction survey;
10. Number of customer complaints to the BCUC; and
11. Number of prior period adjustments regarding customer measurement data.

The parties also established the following two directional indicators:

1. Leaks per kilometre of distribution mains.
2. Number of third party distribution system incidents.

Assessment of the PBR Plans

ALBERTA'S PBR PLAN

The AUC adopted a PBR Plan applicable to all the utilities it regulates except for ENMAX. The plan is generic in its approach. The following sections discuss the merits of various decisions related to the components of the Plan. The AUC's PBR plan has a number of components that should be evaluated as part of the assessment of the plan components. The following items will be evaluated below:

1. The productivity factor (X-Factor)
2. The inflation factor (I-Factor)
3. The length of the term
4. The inclusion of non-controllable factors (Z-Factor and others)
5. Earnings sharing (ESM)
6. Off-ramps and reopeners
7. Efficiency carryover mechanism (ECM)

As a result of the serious shortcomings, both theoretical and practical, discussed below, Black and Veatch finds that the AUC PBR Plan should not serve as a model for FortisBC. The AUC Plan is deficient in the determination of TFP for both gas and electric utilities. The AUC Plan suffers from other deficiencies that potentially impact stakeholders negatively in our view.

Productivity Improvement Factor (X-Factor)

The AUC approach to X-Factor relied too heavily on an academic approach that did not reflect either the cost drivers or the proper measure of outputs for electric and gas utilities. As a result this produces TFP values that are unrealistic and inappropriate for use in the FortisBC PBR based on the Black & Veatch assessment of the results.

In the AUC proceeding adopting PBR regulation (Rate Regulation Initiative, Distribution Performance Based Regulation Decision 2012-237), the AUC reviewed a series of TFP estimates provided by a variety of witnesses. Exhibit 1 provides the estimates of the various parties to the proceeding. Each of the proposed studies represents "academic studies" of TFP. Identifying the studies as academic is based on the studies use of the academic paradigm as developed in the initial academic journals related to both theory and practice. The academic paradigm is characterized by a series of assumptions- some explicit and some implicit that provide the description of the model, the data requirements and the theoretical process for making the TFP estimate. In particular, academic studies are constrained by the researcher's understanding of available data, the reach of the basic theoretical models and the necessity to make the model amenable to analysis.

The AUC's use of academic studies, in particular NERA, is problematic because the real world of utility operation is not the world of the current academic paradigm. In order to become useful for application in utility regulation, academic studies must be modified to adequately model the key drivers of cost and be more comprehensive in scope by including all of the costs associated with delivery service. Both of these changes require making the studies more realistic and practical and less academic in nature. The analysis of TFP provided elsewhere has addressed the use of throughput as the measure of output for gas and electric delivery service. (See the report, Estimating Total Factor Productivity Theory and Practice for Gas Distribution Utilities where the report discusses the production function and the estimation of TFP). Black & Veatch concludes that the AUC results are unreliable due to the use of a throughput measure of productivity, as is discussed below.

The implicit assumption of the academic model, employed by the AUC in determining TFP, is that throughput explains the cost structure of the utility including the required costs of the various inputs required to deliver the throughput volume. This assumption has been demonstrated to be false time and again by cost of service analysts. These demonstrations have included theoretical, engineering and operational practices, empirical analysis and so forth. It is also useful to provide some practical examples of the reason that throughput cannot be used to measure output for a TFP study. Consider a gas distribution utility in a growing area that adds 45,000 new customers per year with an average use per customer of 80 GJs. The utility would have a growth in throughput of 36 million GJs per year. If that same gas distribution utility serves a single fertilizer plant that uses 1.6 million GJs per month and must take the plant out of service once every two years for a one month maintenance outage, the volumetric measure of growth every other year is reduced by 44%. Using volume as the measure of output, all else equal, the gas distribution utility's TFP would be significantly lower every other year even without other factors that impact throughput. That lower TFP would not represent any change in productivity. Also for that same utility, the way the 45,000 new customers are added to the system will also impact estimated productivity because if the customers are added as part of a system expansion, the customers require a larger investment than if the customers are added without main expansion. As a result TFP is impacted directly by the percent of customer additions accounted for by adding to the existing system of mains. By using a capacity measure for output, the TFP estimate accounts for the portion of customers who require no new main capacity. If the analysis uses throughput, calculated TFP will vary directly with the portion of new customers not requiring main. This produces an artificial bias in the measurement of TFP that does not exist using the proper measures of output.

Some gas distribution utilities will have large customers where changes in their consumption pattern will directly impact the measure of throughput based on the economics of one customer. The large customer may be a refinery, chemical plant, power plant or other large use customer. In addition, throughput may cause an over-estimation of productivity because of interruptible or seasonal loads depending on the extension policies of the utility. Large seasonal loads such as asphalt plants or grain driers may have large throughput but cause little or no LDC costs because the utility line extension policy may require the customer to provide its own main and service line by paying a full contribution to the utility. Thus, costless service would raise the TFP based on the significant throughput of the customer.

Although these examples are based on a gas distribution utility, similar conclusions apply to an electric distribution utility. For example, electric distribution utilities often have large interruptible customers who are more likely to experience interruptions when weather is more extreme. This may mean that the extra throughput resulting from hotter summers may be offset by reduced interruptible load. During normal weather the actual throughput may be greater as the result of full service to interruptible customers. In this case, models that use weighted loads by class of service have changes in weights that do not reflect productivity at all but rather reflect the differing cost structure of service to different classes of service.

The TFP report by NERA Economic Consulting, which was employed by the AUC in determining TFP, makes this error by using class revenue to weight the output measure of kWh volumes. In addition to the impact of this problem of weighting and changing throughput mix, NERA fails to consider the impact of voltage level of service as it relates to distribution capacity costs. In using class revenue to weight volumes by class there is no accounting for the voltage level of service and its cost impact. For some utilities, the largest industrial customers are served off the transmission system but their throughput is not excluded from the measure of efficiency for the distribution system. Further, many of the larger customers are served directly from the primary distribution system. Most residential customers use the secondary system for service. This would imply the need to weight lower voltage levels of service at a higher rate of capacity requirement if this difference is to be included.

The use of revenues as a weight in the NERA study also distorts the relative use of assets because for the utilities in the study typically residential rates do not recover the full cost of service and smaller commercial customers pay more than the cost of service. The issue of load factor also impacts the measure of TFP even if two utilities are identical. Consider the case of two identical systems except that a significant number of residential customers on one system have both central air conditioning and central electric heating. That system will have a higher load factor based on the summer peak and will appear to be more efficient even with identical costs. This example violates an important assumption of production theory that if output increases cost must also increase. The problem disappears if output is measured as capacity because the system with higher load factor due to heating load will also require higher capacity where facilities serve the winter peaking heating load that exceeds the summer non-coincident peak (NCP) load even though no additional peak hour generating capacity is required. In practical terms, it is likely that all electric homes will have a summer NCP much less than the winter NCP and added capacity in portions of the distribution system will be required for winter load.

These practical examples, as well as the theory discussed in the TFP reports noted above, demonstrate that the use of throughput as a measure of output- the academic model standard- does not properly measure output for electric and gas utilities. The AUC adoption of a throughput measure of utility output, on its own, causes the TFP value to be incorrect. In fact, there are other issues that invalidate the model adopted by the AUC based on specific assumptions underlying the model.

The NERA TFP study was developed for electric utilities. In adopting the NERA model for both gas and electric utilities, the AUC implicitly accepted NERA's assumption that electric TFP was a reasonable measure of gas TFP. That assumption fails to recognize significant differences between gas and electric utilities with respect to the drivers of distribution costs. Further, a reasonable estimate of TFP for both gas and electric utilities cannot rely solely on the cost of distribution because delivery also requires transmission facilities to move either power or gas from source to load. For gas LDCs transmission may be purchased in whole or in part in the cost of supply. Where that is not the case, both outputs and inputs are impacted by the existence of transmission assets as well. In either case, costs and cost drivers suggest that TFP may not be the same for electric and gas utilities. Three significant differences are discussed below.

1. Electric load diversity for the peak hour on the system and the non coincident peak loads on delivery systems increases the more remote the facilities are from the

customer's location. Essentially, electric utilities must have more capacity in transformers than in substations and even less capacity in transmission lines based on diversity. Peak loads are also measured on an hourly basis for electricity. There is virtually no diversity in gas loads as the peak is measured on a design day and almost every firm load customer peaks on the same day. Hourly loads on occasion may require additional investment in the system but this is not the major driving factor in the capacity of the system.

2. Customer related costs associated with connections to the system are very different per unit of capacity for gas and electric. For a typical residential or small commercial customer, the cost of local gas facilities is the same regardless of the capacity requirement because the largest residential or small commercial customers can be served off the same minimum size of pipe installed. This means that on average the costs to serve residential or small commercial customers are the same regardless of throughput as well. For the electric system, the unit cost of connection declines as connected load increases. Since most output growth is related to residential and small commercial customers, gas systems have much higher unit costs for growth than electric utilities and throughput as a measure of output further exacerbates the application of an electric TFP to gas distribution utilities.

3. Gas and electric utilities have differing cost impacts from external events such as weather. The cost consequences from storms and other weather events have more cost impacts on electric utilities than on gas LDCs all else being equal. Storm damages impact both capital and O&M costs for electric utilities through system replacement, overtime and a number of other factors.

The essential point for these examples is that a separate measure of TFP should be used for gas and electric utilities just based on fundamental differences in both the cost and output drivers.

The NERA model estimates TFP solely on distribution plant and the O&M expenses associated with that plant, rather than all costs that make up the revenue requirement for delivery service. Essentially, NERA makes the implicit assumption that TFP related to the revenue requirements or prices can be measured from only a portion of the costs associated with delivery service. This assumption has broad implications for the reliability of the estimates of TFP adopted by the AUC. First, NERA underestimated the cost of labor because the labor costs included in distribution payroll do not include a variety of labor related costs included in administrative and general expenses such as injuries and damages and pensions and benefits. In addition, NERA did not include customer related costs such as meter reading and billing or property taxes that impact capital costs. Thus the assumption to exclude A&G expenses understates the cost for all components of the inputs. In addition, the assumption to not include General Plant excludes a significant cost associated with the delivery system related to the vehicles, power equipment and tools required to maintain the system. In addition, the failure to include stores costs does not recognize the required inventory of supplies that must be used as part of maintaining the system. This means that cost changes did not reflect significant portions of the cost of delivery service in the analysis.

B&V recognizes that the use of customers and capacity as a measure of output is more difficult than using the readily available data from a single source. This conclusion is not surprising given that the standard data reports required by regulatory commissions do not include data on capacity and the source of data to estimate the available capacity requires an understanding of the PHMSA[42] reports and gas flow equations. This type of analysis requires more than theoretical economic analysis. It requires engineering and operational analysis to develop capacity estimates for gas LDCs. More importantly, it also requires an in-depth understanding of the realities of operating gas and electric utilities. However, it is essential to use the proper measure of output if the TFP results are to be used in developing a PBR. The most recent study by the Pacific Economics Group filed in Ontario[43] explicitly recognizes that both capacity and customers must be part of the output variable and gives only small weight to throughput. It is more appropriate to go further than PEG and measure output on customers and capacity alone.

Black& Veatch believes that a theoretically and practically sound TFP is useful for determining an X-Factor; but the value need not be exactly any particular TFP estimate since there are other considerations based on the requirement that the resulting I-X adjustment must reasonably track costs within a future period. To the extent that a TFP is to be used it should not be the TFP adopted by the AUC or even determined with the same methodology.

Inflation (I-Factor)

The AUC chose to use a two part inflation factor representing payroll and other costs weighted based on the portion of payroll expense to other expenses. Since the chosen inflation factor is an important element of the PBR plan the fundamental theoretical question is whether the factor actually tracks cost changes for the utility. By choosing to reflect both the local labor market conditions and the local inflation in consumer prices, the AUC seems to have chosen a factor that may reasonably reflect the inflation related costs for the utilities. The implicit assumption underlying the use of the weighted factor is that the average make up of the data used in the factor estimate is reasonably similar to the utilities payroll. It is hard to assume that the distribution of payroll costs for the province as a whole is similar to the distribution of payroll costs for a utility. It is likely that the utility payroll in general reflects a higher level of skilled workers than the average for the province. Given the limitations on the types of factors generally available, however, the use of a payroll related component is likely to produce a better result than alternatives other than a customized index of inflation that looks at factors for each utility. The drawback of a customized factor is that the results are not transparent and certainly not available in a general economic forecast. In general, the use of local measures of inflation that are available on a forecast basis is sound.

[42] Pipeline and Hazardous Materials Safety Administration of the United States Department of Transportation
[43] Empirical Research in Support of Incentive Rate Setting in Ontario: Report to the Ontario Energy Board. May 2013, PEG

Length of Term

The AUC selected a five year term of the PBR plan. While there are reasons for selecting both shorter and longer periods, it seems that a five year period has become the most common period for review of PBR plans. From a theoretical view, the period must be long enough to permit the utility to earn the expected return on new cost saving technologies and not so long as to permit significant gains or losses for stakeholders. For a well developed plan that includes appropriate plan elements to preserve the fundamental regulatory compact for all stakeholders the five year period seems to be appropriate. The length of the plan must be set in conjunction with off-ramps and reopeners that protect all stakeholders. Further, the plan incentives must be symmetric and reasonable as will be discussed below. Shorter plans have a larger regulatory burden than longer plans in terms of the rate reset frequency. Longer plans have potentially lower regulatory costs but greater uncertainty of outcomes for stakeholders. The five year plan seems to be reasonable so long as other portions of the plan are reasonable. As discussed below certain of the other aspects of the AUC plan seem unreasonable calling into question the length of the plan.

Z-Factor and Other Factors

The AUC adopted a number of factors for use in conjunction with the basic PBR formula. Specifically, the AUC adopted a set of rules for inclusion in the Z-factor[44] that included as a test for materiality based on an impact of 40 basis points after tax. Since Z-Factors are beyond the control of management, it is typical to include a specific list of events that trigger the Z-Factor particularly where the cost changes represent cost changes that would be passed through as part of a cost of service proceeding. The standard list includes changes in taxes such as payroll or income tax changes, regulations that require increased capital or expenses associated with environmental or other regulatory decisions and specific events that may occur beyond the control of the utility. The AUC approach of having the shareholders bear the costs for these events unless they reduce earnings by 40 basis points when these costs should be accumulated and passed through is unreasonable. Essentially, this provision would disallow costs imposed by legislation or regulation that did not meet the threshold without rate recovery even though the utility could not control the cost and absent such a determination those costs would be recoverable from customers. Thus the costs should be recovered in total. Coupled with other aspects of the plan there are significant implications for shareholder risk from the inability to recover actual costs during the term of the PBR plan.

The AUC adopted a Y-Factor to recover another category of uncontrollable costs using the same conditions of the Z-Factor including the 40 basis points materiality test for recovery. Examples of costs eligible for Y-Factor treatment in Alberta include, but are not limited to gas and electric transmission rates charged by transmission service providers, AUC assessment fees, hearing costs, costs as a result of AUC directions, municipals fees and income tax impacts other than tax

[44] The Z-Factor is designed to recover exogenous costs not otherwise under management control and not accounted for under the price or revenue cap.

rate changes. This provision covers some of the standard factors noted above as Z-Factor considerations. Having a separate provision subject to another 40 basis points materiality test suffers from the same issues noted above. More importantly, under traditional cost of service regulation these costs are typically recovered in full pass through automatic adjustment procedures or are subject to deferral and future amortization in rates. This particular treatment is inconsistent with the opportunity to earn the allowed return. The result of the Z-Factor and the Y-Factor could be an earnings erosion of almost 80 basis points due to the utilities' inability to recover legitimate costs of providing service. Given the recent AUC allowed equity return of 8.75% (2011), the companies could suffer a nine percent decline in ROE as the result of the threshold test before any adjustment occurred. At this point, the equity return would be lower than reasonable without factoring in other impacts that might reduce the return further. This seems to be an unreasonable result for a plan designed to provide the utility a reasonable opportunity to earn the allowed return.

The AUC also adopted a K-Factor designed to track capital additions not otherwise tracked in the PBR formula. Given the lumpy nature of capital additions and the growing need for infrastructure replacement, a separate capital tracker is both a reasonable term of a PBR plan and a critical element to maintain a safe and reliable system while providing the utility an opportunity to earn the allowed return. As noted elsewhere in the TFP reports, the addition of infrastructure replacement costs significantly impacts productivity because costs increase without any change in capacity or number of customers. Thus cost increases with no change in output assuring a negative TFP. By including a capital adjustment provision, regulators assure that a consistent program of infrastructure improvement occurs, meeting the goal of a safe and reliable utility system. Capital tracking is essential for assuring safe, reliable and cost effective utility service.

Earnings Sharing Mechanism

The AUC did not adopt earnings sharing as part of the approved plan. Given the level of uncertainty related to determination of the X-Factor, the absence of an earnings sharing mechanism potentially creates greater risks for all stakeholders that outcomes will not meet the test of reasonableness. If the results of the PBR Plan fail to meet the conditions specified in the off-ramp and reopener provision, the potential for adverse impacts on either the utility or its customers may be quite large. The issues related to the off-ramp and reopeners will be discussed separately but directly impact the credibility of the plan. The concept of earnings sharing is based on assuring that an acceptable level of benefits are shared with consumers during the regulatory control period and that the utility is protected from unreasonably low returns in the event of unforeseen plan outcomes. The earnings sharing mechanism benefits both parties and does so without an overtly heavy hand of regulation. If we assume the AUC plan is perfect in all regards, the only direct benefit of the plan to consumers comes in the form of a 0.2 percentage point adjustment below the rate of inflation. If the utilities find ways to increase earnings they would be able to earn significantly above the upper end of the zone of reasonableness for the term of the PBR plan so long as they did not trigger the off-ramp mechanism. None of this benefit would accrue to customers until the reset at the end of the regulatory control period and there would be no way for customers to benefit at that time based on the historic outcomes of the plan.

Similarly, if the AUC plan is defective, the utilities could suffer large losses with unreasonably low earnings that could have negative consequences for consumers in terms of financial downgrades and reluctance to invest new capital when the returns were below the market cost of capital. Further, customers would be faced with a substantial rate increase at the time of reset at the end of the regulatory control period. The end result in either case is less than satisfactory in terms of the fundamental principles of reasonable rates and a reasonable opportunity to earn the allowed return.

Off-Ramps and Re-Openers

The AUC provides for a re-opener under a number of circumstances. The most significant of the factors is based on measures of return. The AUC reopener requires that one of two tests be met before a reopener can occur. The first test is a variance in earned ROE of 500 basis points or greater in one year. As a practical matter, a utility would file a rate case under cost of service before it reached such a low ROE. Similarly a two year period of ROEs below 300 basis points would almost certainly cause a filing after the first year. This is easy to understand when one considers that 500 basis points is a 57% decrease in earned return for utilities subject to the AUC's PBR and a 300 basis point reduction is a 34% decrease in earned return. Both of these values cannot meet the test of just and reasonable rates that provide a reasonable opportunity to earn the allowed return. Further, it is unlikely that under traditional cost of service regulation that a utility would allow itself to operate until these metrics were met without filing a rate case to maintain the necessary financial metrics consistent with its target financial rating. The fundamental issue becomes whether it is reasonable to punish the utility based on an inexact measure of performance at rates far below a level consistent with the market cost of capital. It is reasonable to conclude that the AUC model does not provide a realistic basis for an off-ramp and that the absence of an earnings sharing mechanism imposes a far too harsh adverse result before the utility can be relieved of the financial burden of the PBR Plan.

Efficiency Carryover Mechanism

The AUC approved an ECM based on earned return. Alberta utilities only benefit from the improved efficiency if the result of efficiency improvements provides earnings in excess of the cost of capital overall. Given other features of the plan, the potential for a return on investment in efficiency may be reduced because of the materiality thresholds for recovering cost changes beyond the utilities control. There are easier and more direct ways than used by the AUC to measure and reward efficiency gains. Using direct measures of capital and O&M efficiency gains and permitting those to carryover beyond the PBR period provides incentives for the utility to reduce costs based on an expected payback for the period of the carryover. The longer the period for carryover implies a lower required return for payback of the investment in efficiency while still being reasonably above the cost of capital so that customers also benefit beyond the reset of the regulatory control period.

Closing Comments and Perspectives

It should be recognized that the AUC's PBR Plan is the first such generic plan for the utilities it regulates. By using a generic approach, the AUC made it virtually impossible to reach a settlement reflecting the individual conditions of each utility. Yet, settlement agreements or at a minimum utility specific approaches tend to represent a superior approach to developing a PBR plan that reflects the public interest. As noted above, the AUC's PBR plan, in Black & Veatch's view, is deficient both from a theoretical and practical perspective. The seriousness of these deficiencies cannot be determined based on the information available today. For example, the inherent bias in the TFP study could turn out to be overcome because this first PBR changes the incentives for the utilities and they respond by finding large savings. This scenario seems unlikely because despite the notion voiced by some stakeholders that cost of service regulation promotes inefficiency: investor owned utilities have significant incentives for operating efficiently. These incentives exist relative to investor expectations of earnings and incentive compensation plans for management to meet well defined goals related to operations and cost control. Further, as discussed above the plan has no rational basis for concluding the results will be just and reasonable rates or provides the utility with a reasonable opportunity to earn the allowed return. In our opinion, these serious shortcomings mean that the AUC Plan and the NERA study on which it was based should not be used as a basis for the development of a PBR Plan for FortisBC.

ONTARIO'S 4TH GENERATION IR FOR ELECTRIC DISTRIBUTORS

The OEB has used IR for power distributors for a number of years. As the label for the plan suggests, this is the fourth generation of the plan. It is important to note that all of the elements of the plan have not been approved to date. The determination of an appropriate X-Factor has not been made. The TFP recommended by the OEB's technical advisor - Pacific Economic Group is known at this point. This report will be discussed as part of our review. Certain policy decisions of the OEB played a significant role in the development of the IR Plan. In particular, the Board requires that each utility file standardized statistical reports containing financial and operating data. This data base is available for determination of TFP for the regulated electric power distributors based on the unique circumstances in Ontario including the large number of electric distributors in the province[45]. The OEB has indicated its preference to rely on this substantial data base for both the determination of inflation and TFP measures as will be discussed below. Even with this data base, the OEB has correctly recognized that a one size fits all approach to the IR Plan is not ideal. Rather, the OEB recognizes the need for three plan categories to properly manage the unique nature of the distributor operations and to provide for just and reasonable rates and the opportunity to earn the allowed return.

The recognition that a reasonable plan requires an analysis of individual utilities is consistent with the evolution of PBR where there is a longer history of such plans. It is also consistent with the concept that negotiated settlements are an important element of the development of PBR Plans. In particular, it is useful to observe the evolution of these plans to the use of local data and also local measures of inflation based on both a labor component and a capital cost component which specifically recognizes the capital intensive nature of the electric distribution utilities. The following items will be evaluated below:

1. The productivity factor (X-Factor)
2. The inflation factor (I-Factor)
3. The length of the term
4. The inclusion of non-controllable factors (Z-Factor and others)
5. Earnings sharing (ESM)

[45] Such a data base would be of limited value where the sample size for industry participants in a province is too small to permit statistically valid results for a TFP study.

6. Off-ramps and reopeners
7. Efficiency carryover mechanism (ECM)

Productivity Improvement Factor (X-Factor)

The final decision related to the determination of the X-Factor has not been made as of the time this material is being prepared. We have relied on the evidence filed by the Board's consultant to evaluate the plan. The direction taken by the Board's consultant improves on the state of TFP studies over that adopted by the AUC but does not go far enough to be both theoretically and analytically correct.

In the consultant's evidence, the proposed TFP value is zero. This value is determined based on a measure of inputs and outputs as follows. The input measure uses two components of capital and O&M&A. This approach is superior to the AUC analysis because it recognizes all of the costs associated with delivery not simply the direct costs reported in the distribution portion of the Uniform System of Accounts. The output measure is also superior to the AUC measure in that it uses three components of customers, system capacity based on a peak day and kilowatt-hours each weighted according to cost elasticity values.

Although this measure of output is superior to the AUC measure, it is both theoretically and practically deficient. The errors occur because delivery costs do not change with the number of kilowatt-hours actually delivered. Even though this component has a small weight in the development of output, it is an error to include it at all. Further, the specification of the capacity variable as a system peak hour load does not reflect the costs of serving customers as discussed above relative to the diversity of electric class loads. It is likely that most customer classes do not experience their class NCP loads at the time of the system peak. Further, local facilities will be sized to meet the peak of the customers which may not occur even at the class NCP. As a result the analysis underestimates the actual system capacity. In addition the system peak load introduces unnecessary volatility in the measure of output related to weather and other economic factors that distort TFP. The system capacity is fixed based on the installed capacity of system components. This value may not even change from year to year even with customer growth because of the lumpy nature of capital. The system peak load and the number of customers may well change indicating more output than the actual growth in output. A better measure of capacity would reflect the installed capability of the system to serve load.

Although the zero TFP is certainly more realistic than the AUC's determination of TFP, a superior estimate is produced by accounting for outputs in a more theoretically and practically sound measurement. Recognizing that the modeling has started to depart from the pure academic model used by the AUC, the evolution of the OEB process is moving toward a more theoretically sound estimate of TFP. We should also point out that the value of the X-Factor may include a stretch factor and the same report includes recommendations for a stretch factor based on a number of categories of distributors. The range for the stretch factor is from zero to 0.6%. The zero stretch factor applies to the most efficient of the utilities and the 0.6% to the least efficient utilities. If a stretch factor is to be used, this customized approach to the stretch factor is also useful and recognizes that individual utilities have different capabilities to reduce cost based on their existing level of efficiency.

Inflation (I-Factor)

The OEB has set a policy direction for the inflation factor based on a composite of more provincial industry related impacts. The Board's consultant has recommended a three factor approach to include a capital factor, a local labor cost factor and a non labor O&M&A factor based on a broader measure of inflation. Theoretically these are the appropriate components to consider. As such, this represents the type of evolution that has occurred elsewhere in the development of PBR Plans.

Length of Term

The length of term for the OEB's IR Plan is 5 years under both the IR index plan and the custom plan. This is consistent with the AUC plan, as discussed above. The annual index plan has no fixed term and participants who choose this plan can adopt one of the other plans at any time.

Z-Factor and Other Factors

The OEB's IR Plan includes a Z-Factor based on a test of materiality. The test of materiality is either a fixed amount of revenue requirement for the largest and smallest utilities and a percent of revenue requirement for those who fall in the middle category. In the discussion of the AUC plan, the concept of materiality was discussed as it relates to the impact on earnings and the absence of any materiality test for costs that would be fully recovered under cost of service regulation. Those comments apply here as well.

The OEB IR Plans all include a Y-Factor designed to recover deferral and variance accounts. The use of deferral and variance accounts continues to be appropriate in the context of PBR as it relates to costs that cannot be controlled by management and costs that are passed through by other regulatory decisions.

The OEB also has a K-Factor for capital needs under the standard IR Plan. Under both the Annual and the Custom IR Plans, there is no need for a capital adjustment provision since presumably the custom plan accounts for the extra investment associated with sustainment as part of the multi-year plan. The annual plan is provided for utilities where capital issues are not significant and because they can switch off the plan and if capital becomes an issue presumably they would switch to another option. Given the importance of adequate capital to meet system safety and reliability, the inclusion of the K-Factor or a multi-year capital plan is a reasonable feature of a PBR that accounts for the specific characteristics of the utility under a plan. The K-factor is subject to three tests which roughly correspond to the practical considerations or regulatory principles that would be applicable in a cost of service setting namely the practical issue of materiality, not included in the plan and a prudence standard. All of these elements are reasonable.

Earnings Sharing Mechanism

There is no earnings sharing under the OEB's IR Plan. This decision is discussed in detail above related to the AUC approved plan. Given the level of earnings before the plan may be reviewed, it would be reasonable to permit earnings sharing and reduce the risk for both the utility and its customers as discussed above.

Off-Ramps and Re-Openers

The OEB's IR Plan allows for both a quantitative reopener based on earnings of 300 basis points above or below the allowed return and the option to petition to reopen on an evidentiary basis.

The quantitative reopener suffers from the same defects discussed relative to the AUC plan. The issue of an evidenced based reopener permits the utility to apply to change the plan based on unique circumstances. This is not the same as obtaining approval to rebase the plan. As a result this provision provides no regulatory certainty that a utility would be able to exit the plan even in the face of dire outcomes. Recognizing the other elements of the plan and the uncertainty of future cost recovery under the formula unrelated to actual utility productivity, there appears to be extra uncompensated risk under the proposal. For example, suppose the I-X formula does not track the change in costs even if the utility is efficient because of the miss-estimation of TFP. In that event there could be persistent over or under earnings that are really a reward or punishment for the utility based on something completely out of their control.

Efficiency Carryover Mechanism

Although the OEB has not included an ECM in the past, there is recognition by the OEB of the need for such a mechanism. This is a positive step. However, until the mechanism is available no evaluation is possible.

Closing Comments and Perspectives

The OEB's IR Plan has a number of useful features because it recognizes that a one size fits all plan may not be reasonable based on unique characteristics of the utilities. Nevertheless, there are inherent flaws in the plan with respect to the estimation of TFP. The estimation is an improvement over the AUC estimate in the broader specification of outputs but continues to use a volumetric component. There are other issues identified above that create bias in the estimates of output and also excess volatility unrelated to actual output. The seriousness of these deficiencies cannot be determined based on the information available today. To the extent that the X-Factor is not estimated reliably or there is no reasonable agreement as to the value given the circumstances of the utility, the plan has no rational basis for the stakeholders to conclude the results will be just and reasonable rates or provides the utility with a reasonable opportunity to earn the allowed return.

While the serious shortcomings provide little guidance for the development of the PBR Plan for FortisBC, the resulting TFP factor moves in the logical direction. If the error in specification is eliminated, it is likely that the TFP would be negative as indicated by the logic associated with infrastructure replacement's impact on both cost and output measures. Nevertheless, the OEB has allowed for this issue in a different way under each of the three plan alternatives. Given that the issue of infrastructure replacement is not part of TFP in Ontario the proposed X-Factor of zero may be more reasonable for Ontario but different considerations apply in the case of FortisBC.

ONTARIO'S IR FOR GAS DISTRIBUTORS

The OEB adopted PBR Plans applicable to EGD and to Union. Each Plan is unique to the utility's circumstances and while many elements are common, the approaches differ in some respects. The most important point related to these Plans is that they are the result of comprehensive settlement agreements related to the Plan. As has been noted elsewhere, the use of settlements to the extent possible, improve the overall quality of the PBR plan and the process. The following items will be evaluated below:

1. The productivity factor (X-Factor)
2. The inflation factor (I-Factor)

3. The length of the term
4. The inclusion of non-controllable factors (Z-Factor and others)
5. Earnings sharing (ESM)
6. Off-ramps and reopeners
7. Efficiency carryover mechanism (ECM)

Productivity Improvement Factor (X-Factor)

EGD's Plan is based on revenue per customer. This type of plan falls under the general concept of a revenue cap plan and is common for gas utilities where use per customer is declining. As noted in the discussion of the plan, the distribution revenue requirement per customer per year is adjusted upward for a measure of inflation less an adjustment to assure that revenues increase at a rate below inflation. Essentially, the X-Factor in the formula is a percentage reduction of the inflation factor agreed to as part of a settlement without accepting any formal TFP study value[46]. As the X-Factor is determined as part of a broader settlement agreement, there is no way to analyze the result except as part of that process.

Union's Plan is a modified price cap plan by virtue of an average use per customer adjustment factor that essentially converts the Plan into a revenue cap plan. In the case of Union, the X-Factor was not based on a specific study, but was a settled value based on both a TFP amount and a stretch factor. As the X-Factor is determined as part of a broader settlement agreement, there is no way to analyze the result except as part of that process.

Inflation (I-Factor)

The OEB used as the inflation factor a single measure of inflation based on Canada's Gross Domestic Product Implicit Price Index for Final Domestic Demand (GDP-IPI-FDD). The use of a GDP measure of inflation has been common among other PBR plans. There is recent evidence[47] that this measure of inflation does not track changes in input prices as closely as it should. The key point is that any measure of inflation should track price changes for inputs closely for rates to be just and reasonable. Since this determination is an ex-post determination, it is not possible to conclude that the measure of inflation would not result in tracking costs. Having found this measure is not adequate; it is likely that the measure of inflation will continue to evolve as seen in the proposal for the fourth generation IR Plan for electric distributors.

Length of Term

The Canadian plans appear to be using five (5) years as the length of term. See the previous discussion on the PBR evaluation in Alberta.

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[46] TFP estimates ranged from small negative to small positive values. There were both theoretical and practical issues associated with the studies. As a result, the parties agreed to adjust inflation by a percentage factor that varies over the period. There was evidence in the proceeding that a stretch factor is unnecessary when capital is rebased at the end of the regulatory control period.

[47] Assessment of Union Gas Ltd. and Enbridge Gas Distribution Inc. Incentive Regulation Plans, PEG September 2011, p.66

Z-Factors and Other Factors

Both EGD and Union include a Z-Factor and a Y-Factor. The Z-Factor is subject to a number of cost of service type tests as well as a materiality factor. The cost of service type tests include prudence, uncontrollable expense, and other elements not otherwise included in the I-X formulation. The materiality threshold is that all costs under the Z-Factor must exceed $1.5 million. The issue with the $1.5 million threshold is that the shareholders bear the cost of prudently incurred expenses up to the ceiling before they can recover costs that are otherwise just and reasonable. This point is discussed fully above with respect to the AUC decision.

The Y-Factor represents deferral accounts and pass-through type adjustments related to costs that are beyond the control of the utility such as upstream transportation costs and a variety of other similar costs traditionally recovered outside of the scope of distribution related rates. This treatment is consistent with the opportunity to earn the allowed return. Neither plan contains a K-Factor for extraordinary capital investment. Without knowing the current state of the systems, and the tradeoffs that incurred as part of the settlement, it is impossible to judge the importance of this factor to EGD and Union.

Earnings Sharing Mechanism

EGD's ESM is asymmetric since the LDC only shares earnings with customers above a dead band, and earnings below the dead band are borne only by shareholders. In general, asymmetric ESMs are not reasonable in terms of permitting just and reasonable rates for all stakeholders. Since the result occurred as part of a settlement, it is reasonable to assume that overall the elements of the Plan are in the public interest. For Union, its ESM also is asymmetric. Its Plan has a larger dead band and a different sharing mechanism that only shares the results when the earnings exceed the dead band. Having resulted from a settlement, these provisions must be evaluated in the context of the entire settlement.

Safeguard Mechanisms (Off-Ramps and Re-Openers)

Although both Plans included off-ramps initially, Union's off-ramp was eliminated in a later period along with a revision to its ESM. EGD's off-ramp is based on a 300 basis point differential between its allowed rate of return and its earned weather-normalized rate of return. An assessment of the use of a large dead band in a PBR plan has already been discussed above with regard to Alberta's PBR model. Given the asymmetric ESM and this off-ramp provision, it appears that the resulting sharing is unreasonable. Nevertheless, the parties agreed to the value as part of the broader settlement.

Efficiency Carryover Mechanism

There is no ECM in either of the LDC's Plans. The role of these provisions is discussed above relative to the AUC decision.

Closing Comments and Perspectives

A few points are worth noting relative to the gas LDC's IR Plans. First, the OEB specifically promotes the use of settlements as a regulatory tool for efficient regulatory outcomes. There is an important role for settlement in regulatory proceedings. In general, the results of the settlement process provide little guidance for a litigated result under an IR regime. The results of the IR Plans have been quite positive for the Ontario gas LDCs' stakeholders based on the PEG report cited above. Further evolution can only improve the process and the results as plans evolve over time.

PAST PBR PLANS OF FORTISBC

FortisBC has had PBR Plans for both the gas and the electric utility. Although the plans were applied over different periods and contained different provisions both plans appear to have been successful in providing benefits to stakeholders. The following items will be evaluated below:

1. The productivity factor (X-Factor)
2. The inflation factor (I-Factor)
3. The length of the term
4. The inclusion of non-controllable factors (Z-Factor and others)
5. Earnings sharing (ESM)
6. Off-ramps and reopeners
7. Efficiency carryover mechanism (ECM)

For convenience, FBC will refer to the electric plan and FEI will refer to the gas plan. FEI's most recent PBR Plan was completed in 2009 and was followed by cost of service regulation. The FEI plan was fully developed through a settlement process. As noted above settlements offer certain efficiency processes not available in a litigated case. The FBC Plan was completed in 2011 and was followed by cost of service regulation as well.

The result is that settlements meet the test for approval and all stakeholders have a vested interest in the plan's success. This appears to be the case for the PBR Plan discussed above. The plan is customize for the FEI circumstances and the unique issues faced by the parties to the proceeding. The following discussion discusses various provisions of the plan.

Productivity Improvement Factor (X-Factor)

The X-Factor determination in both plans was not based on any detailed TFP study. Rather, the X-Factor resulted from the negotiation among the parties as part of the settlement process. As discussed above, it is reasonable to assume that settlement produces a reasonable outcome or the settlement could not be achieved. The unique elements of the both plans included the hybrid form of PBR. For FEI both capital and O&M were determined based on a formula. For FBC the formula applied to the Gross O&M before capitalized overheads. Typically, either revenue requirements or prices are subject to the adjustment factor without reference to the individual components of either factor. This provision along with other factors associated with capital, such as K-Factor treatment for CPCN projects and capital rebasing provide for an efficient view of capital that properly emphasizes the importance of capital investment for a gas LDC and an electric distribution utility. The X-factor differed for the two plans based on the settlement. For FEI the X-Factor was a percent of inflation adjustment while for FBC the adjustment was a productivity adjustment that varied over the period.

The Inflation Factor (I-Factor)

The I-Factor used in the settlement was the Consumer Price Index for British Columbia (CPI-BC). Although the use of CPI as a measure of inflation is less than ideal for a utility because CPI measures the change in cost for a basket of goods that do not represent the goods and services purchased by the gas LDC or an electric utility, the parties agreed to this measure and thus it is assumed to be in the public interest. It should be noted that even in the settlement document there was concern expressed relative to labor cost increases not measured by CPI-BC. It is instructive to note that the evolution of PBR Plans for FEI includes a newly proposed change to a composite measure of inflation more reflective of the cost drivers for FEI. Since FEI is proposing both a general measure of inflation and a labor measure, this is a better reflection of price changes.

Length of Term

The parties agreed to initially settle on a four (4) year length of term for FEI and a three (3) year term for FBC. Subsequently, the parties agreed to a two-year extension for FEI that resulted in a six-year term for the Plan and a three year extension for FBC resulting in a five year term. Given that the most common length appears to be five years, this represents a reasonable term for the Plan. For more details related to the length of the plan, see the discussion above related to the AUC Plan.

Z-Factors and Other Factors

The inclusion of non-controllable factors is a common element of most PBR plans. FEI's PBR Plan approved by the BCUC included such factors as did the FBC Plan. The Z-Factor elements for FEI were delineated as part of the Plan and were flowed through as both positive and negative adjustments. The absence of a materiality test makes these plans more reasonable than plans in other jurisdictions. Likewise, FBC provided a list of factors that would trigger operation of the Z-Factor. This is the appropriate treatment for these costs, as discussed above in evaluating the AUC Plan. In addition to the Z-Factor, the FEI and FBC Plans included both a Y-Factor and a K-Factor. The Y-Factor included a number of flow-through adjustments that were necessary to allow the inclusion of costs not subject to the PBR, as well as the continuation of deferral and variance accounts that provided a reasonable opportunity for the LDC to earn the allowed rate of return under either PBR or cost of service regulation. The K-Factor was of particular importance for FBC because it recovered costs associated with an approved capital plan as part of the revenue requirements approved annually. These factors are discussed in more detail related to the AUC Plan.

Earnings Sharing Mechanism

The FEI plan included an earnings sharing mechanism that provided symmetric protection for all stakeholders. As a matter of regulatory policy, this reduces the risk of unfavorable outcomes for both FEI and stakeholders. Particularly, the ESM provided customers with real time benefits if FEI earned above the authorized return and assured customers that FEI would not be permitted to deteriorate financially such that system service, safety and reliability would not be compromised. The FBC ESM used a collared ROE where earnings within the collar were shared and outside the collar were deferred for treatment in the annual review. This method, while somewhat more complex generally provides symmetric protection so long as the standards for treatment outside the collar were the same for either a shortfall or an excess. The added complexity and the potential uncertainty for stakeholders does not seem to be warranted. For more details, see the discussion above related to the AUC Plan.

Safeguard Mechanism (Off-Ramps and Re-Openers)

Both FEI's and FBC's Plans did not include any quantitative reopener or off-ramp provisions. Under the annual review provision, FEI and FBC retained the right to request a change or termination of the Plan if there were unacceptable outcomes associated with the Plan. This provision does not represent the best approach to addressing serious issues with a PBR plan. Nevertheless, it is understandable that a negotiated settlement with a number of the other provisions such as a symmetric ESM and a K-Factor for large CPCN projects provided a reasonable basis for not requiring this safeguard mechanism. For a full discussion of these issues, see the comments related to the AUC Plan.

Efficiency Carryover Mechanism

ECMs are an important factor in assuring that the efficiency incentive is not weakened as the end of the Regulatory Control Period approaches. While not approving the original FEI proposal, the BCUC correctly recognized the need for an incentive to continue beyond the end of the plan and approved a mechanism to reflect the continuing benefit from such improvements. The logic behind this incentive is quite simple. When capital and other costs are rebased at the end of the control period all of the benefits from capital and savings on O&M immediately flow through to customers in lower rates. This means that investments in efficiency that have a longer payback period than the remaining time under the PBR plan would be discouraged because the utility could not expect a full payback on the investment before the savings were appropriated for customers. Unlike FEI, the FBC Plan did not include an ECM. Since capital was not included in the PBR, the annual review required by the exclusion would no longer be a necessity. Nevertheless, the ECM is a critical component of a PBR plan if the goal is to maximize efficiency during the pendency of the Plan.

Closing Comments and Perspectives

FEI's and FBC's past PBR Plans provides valuable perspectives in the evolution to its currently proposed Plan. It is reasonable to conclude that no plan will be perfect in all respects (and thus the importance of settlement in satisfying the public interest). Subsequent plans should improve on the elements of the plan that were deficient and continue those elements that were successful. In particular, FEI and FBC should change the basis for determining the I-Factor and the ECM method. In addition, retaining the successful elements of the plan such as the ESM and the transparency created by the annual review are examples where the prior Plan benefited stakeholders. Further, by recognizing deficiencies of other plans as discussed above FEI and FBC will avoid implementing a Plan that does not represent the best interest of stakeholders. Neither excess earnings nor deficient earnings benefit stakeholders. The Plan should meet the goals of providing just and reasonable rates and a reasonable opportunity to earn the allowed return. If those goals are met all stakeholders benefit from a financially sound utility that provides reasonably priced services and does so with a safe, efficient and reliable system.

Exhibit 1: Productivity Improvement Factor Proposals in Alberta

	ATCO Utilities	EPCOR	Fortis Alberta	Alta Gas	CCA
Starting Point	-0.28 to -1.09	-1.0	-1.0	-1.0 to -1.7	1.32 (G) 1.09 to 1.23 (E)
Productivity Study	NERA TFP	TFP based on NERA	Stats Can MFP Index & NERA TFP	Stats Can MFP Index & NERA TFP	PEG TFP (G) NERA TFP (E)
Time Period	1994 – 2009; and 1999 – 2009	1999 – 2009	2000 – 2009	2000 – 2009	1996 – 2009 (G) 1989 – 2007 (E)
Adjustment for US/Canada Productivity Gap	-1.31 to -1.73	-	-	-	-
Stretch Factor	-	0.2	-	0.1 to 0.2	0.19
Proposed X-Factor	**-2.0**	**-1.0**	**-1.0**	**-1.3**	**1.08 to 1.32**

Description of Methodology

	NERA TFP	PEG TFP/MFP
Study:	TFP of distribution component of electric companies, excluding costs related to power generation, transmission & general overhead	TFP trend of companies as providers of gas transmission, storage, distribution, metering and general administration service
Number of Companies Included	72	34
Company Type	Electric & Gas Electric Combined (US)	Gas Distribution (US)
Data Source:	Public (FERC Form 1)	SNL (Proprietary)
Methodology	Index Approach	Econometric Modeling & Index Approach
Output Measure:	Volumetric	Number of Customers
Time Period	1972 to 2009	1996 to 2009
Position on Time Period	Longest time period available to allow for a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth	Relevant time period for sample period should capture an entire business cycle
X Factor Result	**0.96**	**1.32 to 1.69**

Notable AUC Determinations Re: X Factor Calculation – AUC 2012-237	
1.	AUC not persuaded that a more recent period (10 – 15 yrs) provides a better indication of likely industry TFP trends during PBR term (315)
2.	Using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation. In the absence of external scholarly studies pointing to a structural break, a full 1972 to 2009 is the best indicator of the expected industry productivity growth during the PBR term
3.	Using longest time period for which data is available eliminates inevitable subjectivity involved in choosing a truncated time period and mitigates incentive to "cherry-pick" a start and end date. (319)
4.	The Commission considered the sample size of 34 US gas distributors large enough and diverse enough to produce an adequate TFP estimate
5.	Parties must be provided with the opportunity to a fair hearing, which requires all parties to be able to fully understand, and replicate the studies. Fully transparent info is always preferable to proprietary info. (355)
6.	AUC main concern over PEG TFP/MFO relates to overall lack of transparency with respect to data processing. Adjustments in PEG's study was not clearly documented or explained

Proposed Approaches to Determining Productivity Factor

	Fortis Alberta	UCA	
Approach	Analysis of historical industry productivity trend complemented by company's going-forward costs	Efficiency Benchmarking in light of the level of inefficiency for each particular company	Menu Approach which pairs data on a range of probable productivity performances with associated ROE: Higher X = Higher ROE ceiling. For simplicity, X Factor ROE menu from OEB 2000 Draft Rate Handbook proposed.
X-Factor	Calculated as the value that would set rates to recover Company's COSA over a forecast period	Calculated based on the Company's efficiency level as compared to their peers.	Firms decide which X-Factor to undertake
AUC Determination	Rejected. Resembles too much of a multi-year COS that changes the theoretical basis for utilizing the X-Factor	Rejected. Efficiency benchmarking hard to estimate due to the multitude of historical company specific data required. Also virtually impossible to determine relative efficiency by looking at benchmark data alone.	Rejected. X Factors proposed based on 10 yr data for Ontario Distribution companies do not represent a better indicator of the long-term industry productivity trend than TFP. ROE ceilings do not correspond with Commission Determination in GCOC proceeding. Allowing choice among incentive plans may complicate regulatory task and thereby sacrifice simplicity.

Appendix D2

PRODUCTIVITY REPORTS FROM BLACK & VEATCH

ESTIMATING TOTAL FACTOR PRODUCTIVITY

Theory and Practice for Gas Distribution Utilities

PREPARED FOR

Fasken Martineau DuMoulin LLP

5 JUNE 2013

BLACK & VEATCH
Building a world of difference.

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Introduction and Background

Black & Veatch Canada Company (Black & Veatch) has prepared this study of Total Factor Productivity (TFP) of natural gas local distribution companies (LDCs) operating in the United States. The results of this study can be used to inform the selection of an appropriate productivity or efficiency factor for a natural gas LDC in conjunction with the development of an incentive regulation plan, also known as a Performance-Based Regulation (PBR) plan for setting a utility's natural gas rates.

TFP is simply a measure of how efficiently a firm converts total inputs into total outputs. It is obvious that total inputs consist of many input factors such as capital, labor, raw materials and so forth. The concept behind TFP is to convert these inputs into a single factor that measures how important each input is to the production of the output. For a single product firm, the measure of output is the units of the product produced. In the case of a gas delivery utility the output measure is more complex because the unit of output is measured by both the number of customers served and the design day capacity required to deliver the GJs of natural gas the customers desire to use. In this case, the total output must be converted into a single factor as well.

The determination of TFP is a one step in the development of a PBR plan. As adapted by Stephen Littlechild in the 1980s, the original formulaic version of PBR was simply a measure of inflation minus an adjustment for productivity and efficiency. In this simple model, TFP is the measure of productivity and efficiency and is a building block for the change in revenue or price under the PBR. This form of regulation was suggested as a tool for regulating the prices charged at a level that was less than the rate of inflation. The principal issues associated with the price or revenue caps associated with PBR plans are the determination of the measure of inflation and the determination of the value of the productivity adjustment.

Summary of the Report

The report on TFP provides both a theoretical and practical explanation of the measure of output that must be based on customers and capacity rather than a throughput measure. The report explains the difference between a positive and a negative TFP factor and concludes that because of the growing importance of infrastructure replacement TFPs are more likely to be negative going forward. The report considers both the theory of production and the application of theory to the actual operating circumstances of a natural gas distribution utility in order that the results of the study have practical application to the issues of PBR regulation. A practical consideration for the plan is that the plan must reasonably track controllable costs to be reasonable for stakeholders. The proposed TFP methodology in this report achieves the goals of being theoretically sound and practically justified. The final TFP value must also consider the interaction of TFP with other plan elements to assure that the proposed plan results in reasonable rates and provides the utility an opportunity to earn the allowed return. Care must be taken in using the results of any TFP study values because the underlying assumptions of the study may not match the implementation of a proposed plan. For example, the TFP calculated in this study includes an ex-post measure of capital that may differ from the capital treatment that separates a portion of capital such as CPCNs for treatment outside of the plan.

The following sections explain the process of estimating TFP as a component of the X-Factor (the Productivity Adjustment) in PBR plans using either a price or revenue cap. We begin with a basic theoretical discussion and then turn to the more practical issues associated with the estimation process to be utilized for a utility company.

Theoretical Basis

The measurement of productivity, regardless of the analytical procedures employed, begins with the specification of a production function. In its simplest form, the production function is given by the following equation:

$$\mathbf{q = f\ (k, l)}$$

> where q is the dependent variable output and k and l are independent variables of capital and labor, respectively.

The above production function defines the relationship between the dependent variable output and the independent variables making up the factors of production. Implicit in this concept is that the output is the maximum level of output that can be produced by any given set of factors of production. The production function underlies the estimate of TFP because each level of output corresponds to the different set of inputs required to produce that output. The analysis of TFP measures how efficiently the firm's output changes as the inputs are changed. TFP in its simplest form is the change in output minus the change in input. TFP is positive when output changes faster than input and is negative when inputs change faster than output. As a practical matter, TFP signals whether costs are rising faster or slower than the rate of cost inflation. A negative TFP means that costs are rising faster than inflation and a positive TFP means cost are changing slower than inflation. It is important to note that a negative TFP does not mean inefficiency and a positive TFP does not mean the utility is efficient.

Measurement of TFP- Output

Both the dependent variable q (output) and the independent variables for capital and labor as inputs in the production function require proper specification and measurement. Using an appropriate measurement of the output variable that reflects the reality of the utility business is essential to ensure that the estimates of TFP are unbiased. Using measures of inputs and outputs that are not rooted in the reality of the utility operation produces misleading results and can cause a TFP that is unfair to either the customers or the utility.

TFP output for a utility has several dimensions. For years cost of service analysis has understood that delivery related costs are caused by customers and capacity. Simply, the outputs for delivery service are customer service and connections related to the customers served and the capacity to serve the customers based on the design day capacity of the system. The measurement of output for a gas distribution and transmission utility based on a measure of throughput such as MCFs or GJs violates a fundamental premise of the production model, namely that the dependent variable (output) depends on the independent variables (inputs). A change in the level of throughput for a natural gas utility does not change the level of fixed costs for the utility delivery service all else equal. For the services evaluated as part of the TFP for the utility delivery function, using throughput as a measure of output is a misspecification of the model. For gas distribution, costs are caused by a combination of customers, density, the age of capital, and the design day capacity served by the utility system. There is no volume/throughput-related component of costs except for very minor costs such as gas odorant and system fuel costs.

Further, the use of a measure of volume/throughput creates bias in the estimation of TFP that would cause higher load factor utilities to appear more efficient than lower load factor utilities even if the underlying costs for the system were identical. A higher load factor gas utility has more GJs per unit of design day capacity than a lower load factor utility. There is also bias related to the measure of throughput since natural gas LDCs bill on either volume (CCF, MCF or cubic meters) or BTU content (Therms, Dekatherms or GJs).

It is relatively easy to identify the bias from each of the above examples by illustration. If two natural gas LDCs have identical systems in the distribution of pipe sizes by vintage and type, numbers of customers, rate base, O&M costs and so forth and the only difference is that one of the LDCs has greater throughput because of higher load factor customers that utility will appear to be more productive even for identical costs. That is not the case since both utilities are in fact identical in terms of cost and the ultimate outputs of serving customers and providing design day capacity. The bias associated with the measure of throughput results because the BTU content of natural gas may vary from system to system. Assuming the same two identical utilities with identical gas consumption measured on a BTU content basis, the MCF measure of throughput would be different if the heat content of gas differs resulting in lower MCF for the company with higher BTU content and, thus, lower productivity even with the same costs. Since not all natural gas LDCs bill on a BTU basis, the only common measure of throughput is MCF. Couple the use of throughput as a measure of output with the impact of declining use per customer for many natural gas LDCs and the results of the estimates of TFP become wholly unreliable from a theoretical perspective. Declining use per customer would suggest a decline in TFP even though the LDC provides more capacity and serves more customers. In fact, there are sound theoretical reasons to conclude that the TFP is not a positive number as discussed below.

TFP Positive or Negative

To understand why TFP is likely to be negative we need to understand the individual elements of the production function- labor and capital. Labor productivity has historically increased and will continue to increase in the future, although that increase is in part moderated by the increasing wages paid to labor. However, the capital component represents a far greater portion of the TFP because of the capital intensity of delivery service for gas utilities. From a theoretical basis, the TFP for capital is far more likely to be negative, thus causing the overall TFP to be negative.

The negative productivity for capital is explained by the need to replace aging infrastructure. In terms of capital costs, an aging infrastructure has been almost fully depreciated. Further, because of the age of the asset and the higher capital costs for replacement due to inflation in both labor and capital, the replacement costs will be even greater than the original cost of the asset replaced. The total capital costs of the utility will increase due to replacing aging infrastructure. By definition, the infrastructure replacement does not increase output by any measure of output: it merely allows the utility to continue to serve the existing output. That is, infrastructure replacement just duplicates the current service facilities for the most part and serves the same customers. This means that during periods of significant infrastructure replacement (sustainment capital) costs grow more rapidly than output. Thus the TFP is negative. The negative TFP does not mean the utility is inefficient in its investments or in the production of its outputs. It means that the goal of safe and reliable service at the best cost requires additional new investments that permit the utility to replace old equipment with new equipment that over the life of that investment will provide efficient delivery service.

It is important to recognize a distinction between the capital in mains, meters and services as compared to the traditional views of capital. Under the traditional view of capital, depreciation measures the decline in productivity from using an asset over time. For the bulk of gas distribution and transmission, the productive capacity does not change over time. That is, the capacity of a segment of pipe remains the same over its life. In fact, based on the rating of the pipe segment, the actual capacity may be increased just by raising the operating pressure on the pipe. Raising operating pressure is possible so long as the current operating pressure is less than the maximum allowable operating pressure of the pipe. This would allow for added throughput with no additional investment. This option is only viable where load growth is concentrated in an area of existing utility service. Such growth is often referred to as infill. Infill increases productivity because the new capital cost to serve a customer is less than the embedded costs and the incremental O&M is very low.

It is more likely that a portion of capital investment by utilities during the study period has been used to replace existing facilities. This means declining productivity for capital. While not explicitly recognizing this declining productivity of capital, regulators have approved infrastructure replacement cost recovery factors to supplement the revenue requirement of utilities with approved programs in recognition of the higher cost of production associated with replacing the infrastructure. Given the relative importance of capital to labor, the net result for TFP will be negative as the infrastructure is replaced.

We can use the experience of the electric utilities in the AUC proceedings to illustrate this point. While electric utilities are not directly analogous to gas utilities, the resulting trend of infrastructure replacement has the same impact of TFP. In testimony before the Alberta Utilities Commission (AUC), several witnesses discussed a change in the trend occurring in the US electric utility data in the NERA Economic Consulting (NERA) study used to estimate TFP around 1999 or 2000. This roughly corresponds to the period when broad-based infrastructure replacement programs were being implemented by gas and electric utilities. The TFP study conducted by the NERA that was adopted by the AUC to set the utilities' TFP had negative TFP values in five of the last nine years, and in two other years, the measure was only slightly positive (the data was for electric utilities only and would be of questionable value for that reason alone for application to gas utilities). Averaging the results over the entire study period of 38 years produced the positive TFP value ultimately used in the adopted Plan. However, over the last 9 year period, the TFPs were significantly negative overall averaging about -1.443.

The AUC rejected the negative measure because the output measure was throughput based. The AUC approach to measurement of TFP is flawed and produces unreliable, biased results. The economic downturn that had reduced the kWh measure of output because of economic circumstances even though the theoretically correct measure of output (customers and capacity) may not have increased enough to result in a positive TFP.

The use of a volumetric measure of output for TFP certainly creates this economic bias, whether in the context of electric or gas utilities. The output related to customers and capacity would not suffer from this bias because its measurement does not depend on the economy to the same extent as a volumetric measure. Further, the measure of capacity reflects the fact that capacity is generally constant over the life of the major plant components. That is not to say that there may not be a decline in measured output over time even for the more appropriate customer and capacity measure. Conservation that reduces capacity requirements may eventually result in the installation of lower capacity equipment on the system and migration may reduce the number of customers but these events occur more gradually and would reflect a long-term trend. The results of a NERA type study may have been even more negative using a gas-only database where infrastructure replacement programs are more prevalent. A higher rate of replacement increases input costs without increasing the measure of output.

From a theoretical view, TFP is much more likely to be negative on a going forward basis than it is to be positive. This result occurs because the replacement of aging infrastructure adds cost unrelated to customer growth or additional design day capacity implying a negative TFP. In addition, TFP would also be negative for adding new gas customers who require both main and service line investment because these costs will be higher than the embedded average cost reflected in the cost of service for the utility. The approach to measurement of TFP should be based on the practical reality of the gas system and not a measure output as throughput which is developed from production theory related to widgets or other manufactured products.

Practical Issues

Practical issues arise in every study (including this study), that can limit the precision of the TFP estimate. Despite practical limitations on data and the need for simplifying assumptions, it is vital that the assumptions reflect as closely as possible the reality of utility operations.
Practical issues range from data and data availability to time periods of review and include some or all of the following:

- Ex-ante estimates of the cost of capital or ex-post estimates.
- The length of the period of analysis.
- Direct or indirect measures of variables.
- The variables to be used as a measure of inputs and outputs.
- The level of data disaggregation.
- The sample size needed to produce statistically reliable results.
- The treatment of outliers.
- The treatment of mergers and acquisitions in the data period.
- The treatment of jurisdictional cost allocations within a utility
- Over extended periods treatment of accounting changes and regulatory changes that impact TFP such as depreciation changes, financial downgrades, return policies and so forth.
- The costs used to measure TFP
- The impact of mergers and acquisitions on TFP measurement
- Technological changes occurring over long time periods.

Understanding the practical issues is important in assessing the TFP results. Practical issues limit the precision of the estimates and may even cause the regulator to question whether TFP is positive or negative. A simple example from the AUC adopted NERA study on electric utilities illustrates this point further. By excluding general plant from the capital component of costs, the AUC adopted study failed to include the investment in line trucks and other vehicles used to maintain the distribution system. The study also excluded all of the investment in equipment used to maintain the delivery system. This was an explicit assumption of the study to exclude these costs but an unrealistic assumption when estimating the productivity of delivery service. To then attempt to use this result to estimate the productivity of a gas distribution company where these costs are even more significant because of the underground nature of gas delivery is unrealistic. Although it is not possible to develop an exact measure of TFP, the inclusion or exclusion of particular information may add to the bias of the estimate. Nevertheless, there must be a reasonable value for TFP to permit the PBR Plan to reasonably estimate the costs and cost drivers during the regulatory control period.

Each of these practical issues has an impact on the measurement of TFP. In some cases, the use of a particular variable has an impact on the length of the period required for the analysis. A simple example illustrates this point. As discussed above, some TFP studies use a volumetric measure of output. In order to avoid the impacts of weather and external economic conditions, the use of volumetric outputs require significantly longer periods because of the inherent volatility of the volumetric measure. Where a more correct specification of output based on customers and/or capacity is used, there is no need to use extraordinarily long periods as shorter periods will properly reflect the estimated TFP for more fixed outputs. It is not our intent to discuss each of the practical issues in our list. Rather, the list serves to point out the nature of the issues impacting the estimate of TFP. Using longer periods to estimate productivity for a much shorter PBR Plan may also distort the TFP measure by including technological changes that would not be replicated during the shorter period because they have been fully implemented within the historic period. In addition to the above practical issues, there is another overriding practical issue with the adoption of a PBR plan. The issue is that whether regulation is cost of service based or incentive regulation, there remains an obligation that the utility be provided a reasonable opportunity to earn its allowed rate of return on investment. Thus, whatever elements are adopted as part of the PBR plan, those elements must reasonably track the cost changes expected for a utility that operates at the industry average efficiency level. Recognizing that TFP is just one element of the plan, the whole plan should be assessed against reality. Otherwise, the resulting rates could not be judged to be just and reasonable.

The need for just and reasonable rates under a PBR plan means that each element of the plan must be carefully reviewed so the expectation is that during the regulatory control period a utility operating at the industry average efficiency could expect to earn its allowed rate of return. If the utility operates below the average efficiency it could not reasonably expect to earn the allowed rate of return, but the resulting lower returns should not be so low as to be confiscatory in nature. . For performance above the average efficiency, the utility should be able to earn above the allowed rate of return and beyond a reasonable level the customers should benefit directly in the success of the utility at an improved efficiency level. Customers actually benefit even in the absence of an earnings sharing mechanism by a reset of the cost basis of rates at the start of a new regulatory control period as the efficiency gains become entrenched in the utility's revenue requirements on a going forward basis.

The importance of the practical issues is to assure that the chosen PBR process matches reality as close as possible.

Black & Veatch's TFP Model

Black & Veatch has developed a multifaceted approach to assessing the level of TFP for gas utilities as a basis for providing input into the TFPs chosen by FortisBC as part of its proposed PBR plan. The approach builds on a combination of theoretical literature, practical approaches to estimating TFP, and our detailed understanding of the issues of cost causation based on both empirical and theoretical analysis. In preparing our analysis of TFP, we have made decisions related to the data based on our understanding of the fundamental operating, planning, and engineering realities of gas utilities.

The Black & Veatch analysis begins with the development of the financial and operating data base for gas utilities. It was not possible to use a single data source for the gas utility data base. It was also not possible to use data from Canadian utilities as part of our sample because there is no common data base for these utilities. Further, as the AUC acknowledged there are differences in the reporting requirements for different jurisdictions further limiting the use of Canadian data. As a result, the data used to estimate TFP is based on gas utilities operating in the United States. The use of gas utilities from the United States is a reasonable choice because of the common systems, technologies and operating methods used to provide service. In addition the North American Energy Standards Board includes gas utilities in both Canada and the United States assuring a consistent approach to a variety of operating and other activities between the two countries. A description of the gas data base that was used as our source of data is provided below.

THE NATURAL GAS LDC DATA BASE

The natural gas LDC data base utilizes data for natural gas LDCs in the U.S. and combines information from the SNL Financial data base with information from the Pipeline and Hazardous Material Safety Administration (PHMSA) of the U.S. Department of Transportation. The SNL Financial information is aggregated from annual state regulatory filings made by natural gas LDCs. Both data bases are publically available from the PHMSA or from state commissions. SNL Financial serves as an aggregator of the data. We make certain calculations based on the data as part of our analysis. A summary of the data sources utilized by Black & Veatch and the associated values that are calculated is presented in Schedule 1. In general, the financial data includes accounting variables such as plant, expenses, and revenue. The PHMSA data includes information on miles of pipe by vintage and by size for both distribution and, where applicable, for the transmission facilities of each utility.

The data base consists of 95 utilities operating in 30 states in the U.S. for the period 2007 through 2011. This period represents the latest available five (5) year period for the data. The utilities cover a broad range of sizes with customers served ranging from 86 for Brainard Gas in Ohio to 5,549,399 for Southern California Gas Company. The companies have varied operating histories including companies that have been in existence for over 150 years to companies that have been in existence for less than 20 years. There is also a mix of utilities that require transmission main and those that do not. Pacific Gas and Electric Company has 5,744 miles of transmission main while a number of utilities have none.

The sample represents all of the utilities available with a complete data base from both sources. We have included all net plant for natural gas LDCs as well as all costs including customer accounting costs and Administrative and General (A&G) overheads. It is important to include these costs because their exclusion would result in a substantial over-estimation of the productivity associated with gas delivery since the exclusion of many of the costs associated with plant maintenance and overhead costs associated with labor are included in the A&G cost category. Failure to include these costs under-estimates changes in the cost of inputs and, thus, over-estimates productivity of the labor resource. Further, there are significant costs associated with customer service and billing as well as general plant costs to support these activities. It is reasonable to conclude that the natural gas LDC data base is comprehensive and reflects an adequate sample of financial and operating characteristics. Schedule 2 presents the data for each natural gas LDC used in Black & Veatch's estimation of TFP.

TFP ESTIMATES FOR GAS UTILITIES

TFP is the measure of the rate of change in outputs minus the rate of change in inputs. The measure of both inputs and outputs is a composite measure developed from the data bases described above. The analysis provides for different measures on output based on the critical variables of customer and capacity in order measure a range of potential outcomes. For determining the inputs and outputs, Black & Veatch has used the following measures:

Gas Outputs

- Composite Output- Density-Weighted Number of Customers and Capacity
- Output- Customers
- Output- Capacity

Gas Inputs

- Change in weighted cost of capital and total expenses, excluding gas costs.

Outputs

Each measure of output produces a different level of TFP based upon the characteristics of the changing nature of the output. By using several different measures, the report provides a range of TFP values allowing for the informed selection of the TFP value.

The density weighted customer component is derived using a density index times the number of customers. Density is defined as the number of customers per mile of line. The index is developed based on the first density level in the study.

For the composite output measure, the study uses the percent of distribution pipe less than or equal to 2 inches in diameter to weight the density weighted customer component and one minus the percent of 2-inch distribution pipe to weight the capacity component. This weighting is based on the principle of the minimum gas distribution system that determines the customer-related cost on the smallest size of main typically installed, generally 2-inch pipe. The weight for capacity component is the remainder of the pipe capacity that is the measure of capacity. This weighting process is used for the composite density weighted-customer/ capacity measures. Where output is defined as a single variable, either customer or capacity, there is no weighting required. By using several measures of output, the TFP estimate provides a reasonable range for determining the expected TFP for the utility's future regulatory control period. This provides further development of the range of TFP focusing on the most important aspects of output. This additional information helps to inform the choice of the final TFP value.

The development of a capacity measure for each gas utility relies on flow formulas for distribution mains and transmission mains calculated separately. For distribution mains, the calculation relies on the industry accepted Institute of Gas Technology (IGT) Distribution Equation for a constant pressure drop and length of main. For transmission mains, the equation relies on the industry accepted Weymouth Formula for high pressure mains again holding values constant for pressure drop and length of main. The capacity proxy value is calculated based on the ratio of 2-inch pipe capacity to each of the larger diameters of pipe times the mileage of pipe by diameter. Using the index approach, 2-inch pipe has an index of one (1.00) with other sizes increasing according to the available increase in flow based on pipe diameter. The resulting capacity proxy measures the available extra capacity above the minimum capacity based on the sizes of pipe actually used by the system. By using this proxy method for measuring capacity, it is not necessary to know the actual operating pressures used by each gas utility system as capacity is converted to a multiple of the diameter as opposed to the actual system capacity resulting from specific operating characteristics.

Inputs

The input measure is developed from a capital component and a composite component that reflects labor, materials, services, and rents. Both inputs are measured on an ex-post basis using actual financial data for each natural gas LDC. The ex-post cost of capital is measured as Operating Revenue excluding gas costs and all other operating and maintenance expenses. The resulting revenue represents the cost of capital including return, depreciation, and taxes. The calculation of this cost is based on a method that the Federal Energy Regulatory Commission (FERC) refers to as the *Kahn Method* based on its use in setting the price cap index for oil pipelines regulated by the FERC. The method was developed by Alfred Kahn, a noted regulatory economist, in his initial expert testimony presented in a 1993 regulatory proceeding related to the regulation of oil pipelines under price cap regulation. It is useful to note that the Federal Communications Commission also used the method in telecommunications and that the method has been discussed in reports to the Australian Energy Regulator. The measure of all other costs is a direct composite measure as reported in the financial reports of each company. This method benefits from not having to develop a composite measure or to estimate the quantity of each input used from data that does not permit direct measurement of the quantity of the factor used.

For each of the measures, input and output, the annual change is calculated and the difference between the changes represents the TFP for each particular output measure. Since the estimates are based on actual data that is available from public sources and the calculation of the composite factors are straight forward, this method also has the advantage of data and computational transparency.

It is also important to note that because the measures of output do not suffer from volatility caused by weather or by the business cycle directly, there is much less need for using long historical periods to estimate TFP for use with a much shorter regulatory control period. Using a long period for estimating TFP may include changes in technology that cannot be replicated during the regulatory control period. For example, the technique of live gas main insertion was developed in the early 1980s as a method for replacing cast iron main. Directional drilling for installation of mains has become much more commonplace in the decade after 1984. These factors impact changes in TFP over earlier periods, and that impacts the expected average measure significantly as they became common practice. However, these technological advancements have no additional impact in more recent years because they are stable and broadly adopted technologies. The use of a symmetric period for measurement and control is a sound approach when one removes the volatility of throughput from the measure of output.

TFP Results

The key element of the output measure is that it actually explains the costs that are incurred by the utility to produce the output. The capital and other costs for gas delivery are explained by either capacity or customers. These measures of output avoid the impacts of widely varying outputs that are unrelated to the costs that would occur when output is measured by throughput volume. The range of results from using various measures of output produce consistent results in the range of -0.0313 to -0.0493. Table 1 below provides a summary of the estimates of TFP based on each measure of output and also several other measures of central tendency based on the exclusion of outlying estimates from the principle composite measure.

Table 1 – Summary of TFP Results

TFP Measures	Calculated TFP
Composite Measure	-0.049333794
Customer Measure	-0.049097433
Capacity Measure	-0.042362968
80% of Sample Composite	-0.0340989
50% of Sample Composite	-0.032549875
Median of Sample	-0.031266471
Average	**-0.039784907**
Range	**-0.0313 to -0.0493**

The use of the 80% and 50% of the sample is to test the results by excluding potential outliers in the data. Schedule 2 provides the supporting calculations associated with the summary results in Table 1.

CONCLUSIONS

The gas TFP results derived from the study are theoretically sound and produce results consistent with the logical foundations of TFP analysis and the operating realities of gas utilities. The results represent a more comprehensive review of costs than that found in the AUC analysis and are reasonable as the foundation of a gas TFP value determination taking into account the utility specific elements of the plan.

Schedule 1: Data Sources

Data Sources

Data	Source
Total Plant ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Net Plant ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Operating Revenues ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Gas Cost ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Operating Revenue- Gas Cost	Black & Veatch Calculation
Distribution Expenses (O&M) ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Admin & General Expenses (O&M) ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Customer Service and Information Expenses (O&M) ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Sales Expenses (O&M) ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
Total Gas O&M ($000's)	Annual Filings to State Regulators (Aggregated by SNL Financial)
OE -Gas Cost	Black & Veatch Calculation
Number of Services	US Department of Transportation Pipeline and Hazardous Materials Safety AdministrationAnnual Gas Transmission & Gathering System Form (F 7100.1-2)
Operating Ratio	Black & Veatch Calculation
Total Gas Customers	Annual Filings to State Regulators (Aggregated by SNL Financial)
Miles of Transmission Pipeline	US Department of Transportation Pipeline and Hazardous Materials Safety AdministrationAnnual Gas Distribution System Form (F 7100.1-1)
Miles of Distribution Pipeline	US Department of Transportation Pipeline and Hazardous Materials Safety AdministrationAnnual Gas Transmission & Gathering System Form (F 7100.1-2)
Average Age of Transmission Pipeline	Black & Veatch Calculation
Average Age of Distribution Pipeline	Black & Veatch Calculation
Density	Black & Veatch Calculation
Density Index	Black & Veatch Calculation
Distribution Customer Factor	Black & Veatch Calculation
Estimated Distribution Capacity	Black & Veatch Calculation
Estimated Transmission Capacity	Black & Veatch Calculation
Total Capacity	Black & Veatch Calculation
Cost Change	Black & Veatch Calculation
% Change by Year	Black & Veatch Calculation
Customers/Density Index	Black & Veatch Calculation
Output Measure	Black & Veatch Calculation
% Change by Year	Black & Veatch Calculation
TFP Composite Measure	Black & Veatch Calculation
% Change in Customers	Black & Veatch Calculation
TFP Customers	Black & Veatch Calculation

Schedule 1 (Continued)

State Regulators to which annual filings were provided

State of Operation	State Regulator
Alabama	Alabama Public Service Commission
California	California Public Utilities Commission
Colorado	Colorado Public Utilities Commission
Connecticut	Connecticut Public Utilities Regulatory Authority
Florida	Florida Public Service Commission
Georgia	Georgia Public Service Commission
Idaho	Idaho Public Utilities Commission
Illinois	Illinois Commerce Commission
Indiana	Indiana Utility Regulatory Commission
Kansas	Kansas Corporation Commission
Kentucky	Kentucky Public Service Commission
Maryland	Maryland Public Service Commission
Massachusetts	Massachusetts Department of Public Utilities
Michigan	Michigan Public Service Commission
Missouri	Missouri Public Service Commission
New Jersey	New Jersey Board of Public Utilities
New York	New York State Public Service Commission
North Carolina	North Carolina Utilities Commission
Ohio	Public Utilities Commission of Ohio
Oklahoma	Oklahoma Corporation Commission
Pennsylvania	Pennsylvania Public Utility Commission
South Carolina	Public Service Commission of South Carolina
Tennessee	Tennessee Regulatory Authority
Texas	Railroad Commission of Texas
Vermont	Vermont Public Service Board
Virginia	Virginia State Corporation Commission
Washington	Washington Utilities and Transportation Commission
West Virginia	Public Service Commission of West Virginia
Wisconsin	Public Service Commission of Wisconsin
Wyoming	Wyoming Public Service Commission

Schedule 2: Natural Gas LDC Data Base

Schedule 2: Natural Gas LDC Data Base

A	B	C	D	E	F	G	H	I	J	K
Formula:						**E-F**		**H-F**	**I/G**	
Utility	**State of Operation**	**Year**	**Net Plant ($000's)**	**Operating Revenues ($000's)**	**Gas Cost ($000's)**	**Operating Revenue- Gas Cost**	**Total Gas O&M ($000's)**	**OE -Gas Cost**	**Operating Ratio**	**Gas Customers**
Alabama Gas Corporation	**AL**	**2007**	660,339	638,224	331,835	306,389	472,021	140,186	0.46	451,167
Alabama Gas Corporation	**AL**	**2008**	686,366	620,364	309,720	310,644	449,232	139,512	0.45	447,062
Alabama Gas Corporation	**AL**	**2009**	721,700	637,546	321,964	315,582	459,569	137,605	0.44	444,268
Alabama Gas Corporation	**AL**	**2010**	782,622	644,549	326,958	317,591	470,364	143,406	0.45	437,329
Alabama Gas Corporation	**AL**	**2011**	813,428	537,136	230,440	306,696	376,653	146,213	0.48	427,601
Atlanta Gas Light Company	**GA**	**2007**	1,975,891	570,972	103,142	467,830	289,281	186,139	0.40	1,558,679
Atlanta Gas Light Company	**GA**	**2008**	2,060,007	606,087	136,582	469,505	320,183	183,601	0.39	1,557,230
Atlanta Gas Light Company	**GA**	**2009**	2,104,788	496,081	24,360	471,721	214,956	190,596	0.40	1,514,629
Atlanta Gas Light Company	**GA**	**2010**	2,242,756	562,129	54,773	507,356	247,963	193,190	0.38	1,512,949
Atlanta Gas Light Company	**GA**	**2011**	2,396,061	560,938	21,290	539,648	210,413	189,123	0.35	1,510,957
Baltimore Gas and Electric Company	**MD**	**2007**	801,205	962,769	642,330	320,439	793,523	151,193	0.47	646,186
Baltimore Gas and Electric Company	**MD**	**2008**	818,235	1,024,012	697,287	326,725	849,744	152,457	0.47	648,934
Baltimore Gas and Electric Company	**MD**	**2009**	847,888	758,287	453,343	304,944	606,957	153,614	0.50	650,861
Baltimore Gas and Electric Company	**MD**	**2010**	898,555	709,366	390,398	318,968	540,411	150,013	0.47	652,594
Baltimore Gas and Electric Company	**MD**	**2011**	942,874	671,741	337,378	334,363	491,168	153,790	0.46	653,154
Berkshire Gas Company	**MA**	**2007**	148,207	72,812	42,042	30,770	54,004	11,962	0.39	35,468
Berkshire Gas Company	**MA**	**2008**	148,457	82,094	50,504	31,590	62,643	12,139	0.38	35,633
Berkshire Gas Company	**MA**	**2009**	147,001	64,043	31,024	33,019	44,140	13,116	0.40	35,903
Berkshire Gas Company	**MA**	**2010**	139,173	67,162	33,786	33,376	45,921	12,135	0.36	35,947
Berkshire Gas Company	**MA**	**2011**	141,824	64,948	31,162	33,786	44,608	13,446	0.40	36,244
Bluefield Gas Company	**WV**	**2007**	6,148	10,857	8,688	2,169	9,874	1,186	0.55	3,446
Bluefield Gas Company	**WV**	**2008**	6,283	9,507	7,485	2,022	8,479	994	0.49	3,692
Bluefield Gas Company	**WV**	**2009**	6,334	9,031	6,782	2,249	7,867	1,085	0.48	3,540
Bluefield Gas Company	**WV**	**2010**	6,227	7,436	5,353	2,083	6,402	1,049	0.50	3,540
Bluefield Gas Company	**WV**	**2011**	6,250	7,165	4,977	2,188	6,055	1,078	0.49	3,492
Boston Gas Company	**MA**	**2007**	1,777,792	1,275,983	891,717	384,266	1,084,735	193,018	0.50	589,022
Boston Gas Company	**MA**	**2008**	1,395,724	1,334,201	940,284	393,917	1,148,646	208,362	0.53	615,321
Boston Gas Company	**MA**	**2009**	1,627,081	1,093,274	690,464	402,810	917,060	226,596	0.56	604,259
Boston Gas Company	**MA**	**2010**	1,716,407	1,090,417	676,071	414,346	889,397	213,326	0.51	607,188
Boston Gas Company	**MA**	**2011**	1,830,312	1,216,144	675,951	540,193	939,446	263,495	0.49	667,260
Brainard Gas Corp.	**OH**	**2007**	265	270	115	155	225	110	0.71	86
Brainard Gas Corp.	**OH**	**2008**	425	406	208	198	329	121	0.61	98
Brainard Gas Corp.	**OH**	**2009**	429	439	214	225	343	129	0.57	134
Brainard Gas Corp.	**OH**	**2010**	555	316	89	227	203	114	0.50	151
Brainard Gas Corp.	**OH**	**2011**	561	431	212	219	358	146	0.67	164
Central Hudson Gas & Electric Corporation	**NY**	**2007**	158,964	165,750	110,788	54,962	137,892	27,104	0.49	73,211
Central Hudson Gas & Electric Corporation	**NY**	**2008**	171,650	189,869	130,328	59,541	161,783	31,455	0.53	74,159
Central Hudson Gas & Electric Corporation	**NY**	**2009**	188,286	174,445	107,965	66,480	143,168	35,203	0.53	74,350
Central Hudson Gas & Electric Corporation	**NY**	**2010**	194,336	157,307	75,888	81,419	116,310	40,422	0.50	74,933
Central Hudson Gas & Electric Corporation	**NY**	**2011**	202,769	162,367	77,537	84,830	122,077	44,540	0.53	75,400
Chattanooga Gas Company	**TN**	**2007**	103,962	95,911	64,551	31,360	75,139	10,588	0.34	61,365
Chattanooga Gas Company	**TN**	**2008**	108,801	124,530	93,031	31,499	103,754	10,723	0.34	61,322
Chattanooga Gas Company	**TN**	**2009**	106,687	90,449	59,556	30,893	70,976	11,420	0.37	61,557
Chattanooga Gas Company	**TN**	**2010**	107,502	90,741	59,346	31,395	70,032	10,686	0.34	61,747
Chattanooga Gas Company	**TN**	**2011**	111,244	79,408	48,469	30,939	59,336	10,867	0.35	62,096
Chesapeake Utilities Corporation	**MD**	**2007**	18,272	24,266	16,585	7,681	19,849	3,264	0.42	12,263
Chesapeake Utilities Corporation	**MD**	**2008**	19,420	24,699	16,806	7,893	20,448	3,642	0.46	12,354
Chesapeake Utilities Corporation	**MD**	**2009**	21,347	22,642	14,046	8,596	17,992	3,946	0.46	12,395

Schedule 2: Natural Gas LDC Data Base

A	B	C	D	E	F	G	H	I	J	K
Formula:						**E-F**		**H-F**	**I/G**	
Utility	**State of Operation**	**Year**	**Net Plant ($000's)**	**Operating Revenues ($000's)**	**Gas Cost ($000's)**	**Operating Revenue- Gas Cost**	**Total Gas O&M ($000's)**	**OE -Gas Cost**	**Operating Ratio**	**Gas Customers**
Chesapeake Utilities Corporation	**MD**	**2010**	22,214	21,580	12,645	8,935	16,629	3,984	0.45	12,355
Chesapeake Utilities Corporation	**MD**	**2011**	23,825	19,581	10,408	9,173	14,277	3,869	0.42	12,446
Cheyenne Light, Fuel and Power Company	**WY**	**2007**	37,236	32,467	22,650	9,817	28,714	6,064	0.62	33,016
Cheyenne Light, Fuel and Power Company	**WY**	**2008**	39,360	48,296	33,735	14,561	41,064	7,329	0.50	33,269
Cheyenne Light, Fuel and Power Company	**WY**	**2009**	41,850	35,613	20,859	14,754	28,629	7,770	0.53	33,560
Cheyenne Light, Fuel and Power Company	**WY**	**2010**	44,447	37,591	23,064	14,527	30,887	7,823	0.54	34,113
Cheyenne Light, Fuel and Power Company	**WY**	**2011**	48,141	36,818	21,998	14,820	29,465	7,467	0.50	34,626
Citizens Gas Fuel Company	**MI**	**2007**	13,799	32,527	24,696	7,831	29,192	4,496	0.57	17,146
Citizens Gas Fuel Company	**MI**	**2008**	13,460	33,657	26,396	7,261	30,832	4,436	0.61	17,092
Citizens Gas Fuel Company	**MI**	**2009**	13,344	25,733	18,465	7,268	22,964	4,499	0.62	17,118
Citizens Gas Fuel Company	**MI**	**2010**	13,222	22,985	15,246	7,739	19,568	4,322	0.56	17,172
Citizens Gas Fuel Company	**MI**	**2011**	13,141	23,348	15,315	8,033	19,774	4,459	0.56	17,197
Colonial Gas Company	**MA**	**2007**	701,375	352,336	260,601	91,735	296,516	35,915	0.39	186,719
Colonial Gas Company	**MA**	**2008**	534,919	355,289	263,995	91,294	302,893	38,898	0.43	196,198
Colonial Gas Company	**MA**	**2009**	531,342	286,829	194,997	91,832	240,879	45,882	0.50	193,048
Colonial Gas Company	**MA**	**2010**	536,834	266,878	179,183	87,695	219,820	40,637	0.46	191,936
Colonial Gas Company	**MA**	**2011**	414,730	292,727	178,510	114,217	224,199	45,689	0.40	187,434
Colorado Natural Gas, Inc.	**CO**	**2007**	50,165	12,930	6,387	6,543	7,483	1,096	0.17	7,696
Colorado Natural Gas, Inc.	**CO**	**2008**	66,412	14,017	6,250	7,767	7,414	1,164	0.15	8,145
Colorado Natural Gas, Inc.	**CO**	**2009**	79,777	16,777	6,969	9,808	8,357	1,388	0.14	10,876
Colorado Natural Gas, Inc.	**CO**	**2010**	93,055	16,544	6,115	10,429	7,877	1,762	0.17	12,740
Colorado Natural Gas, Inc.	**CO**	**2011**	103,411	20,296	7,620	12,676	9,947	2,327	0.18	16,804
Columbia Gas of Kentucky, Incorporated	**KY**	**2007**	147,383	160,751	111,661	49,090	135,689	24,028	0.49	138,697
Columbia Gas of Kentucky, Incorporated	**KY**	**2008**	156,009	208,429	155,095	53,334	182,978	27,883	0.52	137,538
Columbia Gas of Kentucky, Incorporated	**KY**	**2009**	163,674	156,327	103,115	53,212	134,094	30,979	0.58	135,605
Columbia Gas of Kentucky, Incorporated	**KY**	**2010**	168,312	136,789	79,645	57,144	111,063	31,418	0.55	134,869
Columbia Gas of Kentucky, Incorporated	**KY**	**2011**	177,209	145,314	86,256	59,058	117,184	30,928	0.52	134,272
Columbia Gas of Maryland, Incorporated	**MD**	**2007**	54,353	53,945	35,391	18,554	43,723	8,332	0.45	32,630
Columbia Gas of Maryland, Incorporated	**MD**	**2008**	59,951	58,442	40,337	18,105	49,384	9,047	0.50	32,440
Columbia Gas of Maryland, Incorporated	**MD**	**2009**	65,436	51,121	33,048	18,073	42,923	9,875	0.55	32,390
Columbia Gas of Maryland, Incorporated	**MD**	**2010**	70,495	43,328	24,326	19,002	33,826	9,500	0.50	32,343
Columbia Gas of Maryland, Incorporated	**MD**	**2011**	78,328	41,719	21,974	19,745	31,700	9,726	0.49	32,376
Columbia Gas of Ohio, Incorporated	**OH**	**2007**	1,187,243	1,934,269	1,348,992	585,277	1,646,099	297,107	0.51	1,409,598
Columbia Gas of Ohio, Incorporated	**OH**	**2008**	1,276,115	2,353,944	1,833,903	520,041	2,145,983	312,080	0.60	1,402,997
Columbia Gas of Ohio, Incorporated	**OH**	**2009**	1,373,141	1,404,168	760,021	644,147	1,098,061	338,040	0.52	1,399,281
Columbia Gas of Ohio, Incorporated	**OH**	**2010**	1,495,862	1,261,040	623,343	637,697	945,435	322,092	0.51	1,396,570
Columbia Gas of Ohio, Incorporated	**OH**	**2011**	1,667,181	1,231,058	644,232	586,826	908,059	263,827	0.45	1,396,393
Columbia Gas of Pennsylvania, Inc.	**PA**	**2007**	567,115	650,519	464,832	185,687	586,043	121,211	0.65	411,182
Columbia Gas of Pennsylvania, Inc.	**PA**	**2008**	632,730	781,900	579,318	202,582	704,877	125,559	0.62	412,450
Columbia Gas of Pennsylvania, Inc.	**PA**	**2009**	669,620	544,896	323,626	221,270	451,226	127,600	0.58	412,814
Columbia Gas of Pennsylvania, Inc.	**PA**	**2010**	728,488	559,163	340,635	218,528	475,339	134,704	0.62	414,485
Columbia Gas of Pennsylvania, Inc.	**PA**	**2011**	840,766	504,751	279,652	225,099	417,488	137,836	0.61	415,716
Columbia Gas of Virginia, Incorporated	**VA**	**2007**	434,070	342,133	231,988	110,145	287,356	55,368	0.50	235,086
Columbia Gas of Virginia, Incorporated	**VA**	**2008**	449,274	414,744	302,524	112,220	351,676	49,152	0.44	236,837
Columbia Gas of Virginia, Incorporated	**VA**	**2009**	468,739	362,295	246,153	116,142	296,907	50,754	0.44	238,523
Columbia Gas of Virginia, Incorporated	**VA**	**2010**	502,922	361,684	235,399	126,285	288,639	53,240	0.42	240,699
Columbia Gas of Virginia, Incorporated	**VA**	**2011**	521,934	328,336	200,945	127,391	259,491	58,546	0.46	242,816
Connecticut Natural Gas Corporation	**CT**	**2007**	532,358	405,471	254,275	151,196	308,183	53,908	0.36	153,528

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Utility	State of Operation	Year	Net Plant ($000's)	Operating Revenues ($000's)	Gas Cost ($000's)	Operating Revenue- Gas Cost	Total Gas O&M ($000's)	OE -Gas Cost	Operating Ratio	Gas Customers
Connecticut Natural Gas Corporation	CT	2008	534,568	463,118	310,601	152,517	374,515	63,914	0.42	156,594
Connecticut Natural Gas Corporation	CT	2009	516,813	351,191	211,030	140,161	290,509	79,479	0.57	157,010
Connecticut Natural Gas Corporation	CT	2010	408,610	360,134	221,341	138,793	282,762	61,421	0.44	158,763
Connecticut Natural Gas Corporation	CT	2011	376,308	348,438	201,805	146,633	266,745	64,940	0.44	160,182
Consolidated Edison Company of New York, Inc.	NY	2007	2,211,719	1,763,978	976,338	787,640	1,199,961	223,623	0.28	1,184,245
Consolidated Edison Company of New York, Inc.	NY	2008	2,441,227	1,843,509	997,546	845,963	1,259,518	261,972	0.31	1,068,723
Consolidated Edison Company of New York, Inc.	NY	2009	2,653,359	1,749,984	860,471	889,513	1,142,507	282,036	0.32	1,058,396
Consolidated Edison Company of New York, Inc.	NY	2010	2,895,843	1,546,235	572,838	973,397	919,397	346,559	0.36	1,062,121
Consolidated Edison Company of New York, Inc.	NY	2011	3,151,890	1,525,875	517,617	1,008,258	884,421	366,804	0.36	1,065,008
Consumers Energy Company	MI	2007	1,500,495	2,629,164	1,917,594	711,570	2,256,587	338,993	0.48	1,708,656
Consumers Energy Company	MI	2008	1,494,376	2,827,084	2,078,954	748,130	2,443,313	364,359	0.49	1,706,276
Consumers Energy Company	MI	2009	1,654,196	2,562,648	1,777,658	784,990	2,173,804	396,146	0.50	1,724,470
Consumers Energy Company	MI	2010	1,828,354	2,360,409	1,516,349	844,060	1,916,462	400,113	0.47	1,704,355
Consumers Energy Company	MI	2011	1,867,704	2,332,104	1,438,216	893,888	1,868,243	430,027	0.48	1,707,987
Corning Natural Gas Corporation	NY	2007	19,629	23,926	14,874	9,052	21,477	6,603	0.73	14,537
Corning Natural Gas Corporation	NY	2008	23,428	26,033	15,920	10,113	22,253	6,333	0.63	14,587
Corning Natural Gas Corporation	NY	2009	27,071	22,566	11,383	11,183	17,907	6,524	0.58	14,589
Corning Natural Gas Corporation	NY	2010	31,490	22,180	9,849	12,331	16,587	6,738	0.55	14,700
Corning Natural Gas Corporation	NY	2011	34,587	21,889	9,382	12,507	15,819	6,437	0.51	14,779
Delta Natural Gas Company, Inc.	KY	2007	117,853	56,400	29,813	26,587	41,623	11,810	0.44	37,053
Delta Natural Gas Company, Inc.	KY	2008	121,187	69,324	39,926	29,398	53,381	13,455	0.46	36,353
Delta Natural Gas Company, Inc.	KY	2009	124,705	57,837	30,080	27,757	43,151	13,071	0.47	35,933
Delta Natural Gas Company, Inc.	KY	2010	127,986	50,434	20,779	29,655	33,415	12,636	0.43	35,841
Delta Natural Gas Company, Inc.	KY	2011	129,781	51,184	19,409	31,775	31,050	11,641	0.37	35,487
DTE Gas Company	MI	2007	1,569,239	1,808,128	1,130,989	677,139	1,531,603	400,614	0.59	1,252,130
DTE Gas Company	MI	2008	1,687,291	2,106,152	1,370,573	735,579	1,818,463	447,890	0.61	1,240,504
DTE Gas Company	MI	2009	1,740,599	1,747,409	1,047,580	699,829	1,454,088	406,508	0.58	1,225,226
DTE Gas Company	MI	2010	1,796,086	1,615,936	860,098	755,838	1,258,479	398,381	0.53	1,215,163
DTE Gas Company	MI	2011	1,891,178	1,482,138	728,531	753,607	1,117,876	389,345	0.52	1,213,199
Duke Energy Kentucky, Inc.	KY	2007	227,125	140,668	95,974	44,694	121,682	25,708	0.58	94,782
Duke Energy Kentucky, Inc.	KY	2008	248,597	144,287	107,630	36,657	127,991	20,361	0.56	95,386
Duke Energy Kentucky, Inc.	KY	2009	276,191	119,452	72,648	46,804	92,825	20,177	0.43	95,090
Duke Energy Kentucky, Inc.	KY	2010	287,961	139,332	68,769	70,563	89,801	21,032	0.30	95,007
Duke Energy Kentucky, Inc.	KY	2011	290,468	115,204	55,289	59,915	76,422	21,133	0.35	95,003
Duke Energy Ohio, Inc.	OH	2007	811,494	586,536	358,293	228,243	459,966	101,673	0.45	423,570
Duke Energy Ohio, Inc.	OH	2008	897,122	641,156	383,725	257,431	470,247	86,522	0.34	424,306
Duke Energy Ohio, Inc.	OH	2009	974,100	530,507	261,463	269,044	343,544	82,081	0.31	420,435
Duke Energy Ohio, Inc.	OH	2010	1,061,363	481,420	205,290	276,130	308,966	103,676	0.38	418,138
Duke Energy Ohio, Inc.	OH	2011	1,146,439	445,655	158,033	287,622	275,136	117,103	0.41	417,466
East Ohio Gas Company	OH	2007	1,191,782	1,082,277	467,768	614,509	796,901	329,133	0.54	1,209,803
East Ohio Gas Company	OH	2008	1,296,905	1,331,663	643,981	687,682	1,019,821	375,840	0.55	1,201,267
East Ohio Gas Company	OH	2009	1,452,650	1,043,041	396,869	646,172	747,965	351,096	0.54	1,193,773
East Ohio Gas Company	OH	2010	1,582,554	963,929	221,446	742,483	639,118	417,672	0.56	1,186,545
East Ohio Gas Company	OH	2011	1,762,884	953,021	200,132	752,889	594,761	394,629	0.52	1,181,925
Eastern Natural Gas Company	OH	2007	2,821	10,259	8,104	2,155	9,977	1,873	0.87	6,650
Eastern Natural Gas Company	OH	2008	2,642	10,936	8,633	2,303	10,569	1,936	0.84	6,612
Eastern Natural Gas Company	OH	2009	2,450	8,029	5,884	2,145	7,788	1,904	0.89	6,552
Eastern Natural Gas Company	OH	2010	2,339	7,715	5,505	2,210	7,431	1,926	0.87	6,564

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Eastern Natural Gas Company	OH	2011	2,405	8,213	5,907	2,306	7,857	1,950	0.85	6,511
Empire District Gas Company	MO	2007	43,760	53,189	30,404	22,785	44,236	13,832	0.61	45,949
Empire District Gas Company	MO	2008	47,682	57,914	40,922	16,992	47,757	6,835	0.40	44,712
Empire District Gas Company	MO	2009	47,384	50,435	27,946	22,489	41,403	13,457	0.60	44,127
Empire District Gas Company	MO	2010	54,593	50,885	26,639	24,246	36,883	10,244	0.42	44,487
Empire District Gas Company	MO	2011	56,145	46,430	22,760	23,670	31,814	9,054	0.38	43,488
Energy West, Incorporated	WY	2007	7,823	11,206	7,717	3,489	9,761	2,044	0.59	6,151
Energy West, Incorporated	WY	2008	8,065	12,307	8,605	3,702	10,566	1,961	0.53	6,273
Energy West, Incorporated	WY	2009	8,242	9,663	6,142	3,521	8,044	1,902	0.54	6,376
Energy West, Incorporated	WY	2010	8,165	8,711	5,239	3,472	7,306	2,067	0.60	6,464
Energy West, Incorporated	WY	2011	8,237	9,720	6,078	3,642	8,089	2,011	0.55	6,525
Fitchburg Gas and Electric Light Company	MA	2007	46,464	34,220	20,346	13,874	26,255	5,909	0.43	15,121
Fitchburg Gas and Electric Light Company	MA	2008	49,238	37,030	21,535	15,495	25,938	4,403	0.28	15,221
Fitchburg Gas and Electric Light Company	MA	2009	52,292	34,769	24,007	10,762	32,212	8,205	0.76	15,258
Fitchburg Gas and Electric Light Company	MA	2010	54,560	29,896	14,045	15,851	22,130	8,085	0.51	15,273
Fitchburg Gas and Electric Light Company	MA	2011	56,299	31,552	8,720	22,832	15,851	7,131	0.31	15,394
Florida Public Utilities Company	FL	2007	72,612	64,850	32,483	32,367	49,919	17,436	0.54	52,037
Florida Public Utilities Company	FL	2008	74,918	72,624	40,429	32,195	58,171	17,742	0.55	52,045
Florida Public Utilities Company	FL	2009	78,180	59,403	21,961	37,442	42,534	20,573	0.55	51,709
Florida Public Utilities Company	FL	2010	72,471	69,162	26,005	43,157	44,513	18,508	0.43	52,165
Florida Public Utilities Company	FL	2011	82,442	63,840	21,277	42,563	40,230	18,953	0.45	52,963
Hope Gas, Inc.	WV	2007	148,252	202,454	140,165	62,289	174,170	34,005	0.55	114,601
Hope Gas, Inc.	WV	2008	151,759	190,455	124,330	66,125	162,348	38,018	0.57	114,156
Hope Gas, Inc.	WV	2009	157,098	163,338	100,168	63,170	135,456	35,288	0.56	113,704
Hope Gas, Inc.	WV	2010	160,585	127,587	56,417	71,170	88,954	32,537	0.46	113,472
Hope Gas, Inc.	WV	2011	167,113	124,048	55,538	68,510	85,041	29,503	0.43	113,485
Illinois Gas Company	IL	2007	6,823	12,961	9,390	3,571	11,327	1,937	0.54	9,817
Illinois Gas Company	IL	2008	6,619	15,482	11,536	3,946	13,799	2,263	0.57	9,745
Illinois Gas Company	IL	2009	6,349	10,812	7,479	3,333	9,448	1,969	0.59	9,722
Illinois Gas Company	IL	2010	6,268	10,329	6,877	3,452	8,838	1,961	0.57	9,727
Illinois Gas Company	IL	2011	6,077	9,317	5,794	3,523	7,733	1,939	0.55	9,694
Indiana Gas Company, Inc.	IN	2007	737,344	762,858	513,020	249,838	614,149	101,129	0.40	559,569
Indiana Gas Company, Inc.	IN	2008	759,245	864,955	595,267	269,688	700,715	105,448	0.39	560,976
Indiana Gas Company, Inc.	IN	2009	766,781	664,163	394,212	269,951	510,255	116,043	0.43	559,008
Indiana Gas Company, Inc.	IN	2010	753,741	624,300	355,488	268,812	466,201	110,713	0.41	561,436
Indiana Gas Company, Inc.	IN	2011	753,900	584,152	314,833	269,319	424,799	109,966	0.41	563,447
Intermountain Gas Company	ID	2007	190,025	339,345	257,489	81,856	298,437	40,948	0.50	284,911
Intermountain Gas Company	ID	2008	193,860	352,001	261,898	90,103	303,436	41,538	0.46	299,549
Intermountain Gas Company	ID	2009	197,190	335,692	247,134	88,558	290,086	42,952	0.49	305,309
Intermountain Gas Company	ID	2010	202,179	271,864	186,691	85,173	225,592	38,901	0.46	309,116
Intermountain Gas Company	ID	2011	203,049	291,887	199,950	91,937	240,757	40,807	0.44	312,565
Kansas Gas Service Company	KS	2007	882,410	827,473	560,170	267,303	688,512	128,342	0.48	638,729
Kansas Gas Service Company	KS	2008	905,380	848,058	582,163	265,895	717,016	134,853	0.51	631,669
Kansas Gas Service Company	KS	2009	933,167	688,738	421,520	267,218	556,822	135,302	0.51	633,596
Kansas Gas Service Company	KS	2010	963,188	684,370	409,230	275,140	540,932	131,702	0.48	632,152
Kansas Gas Service Company	KS	2011	1,004,510	580,077	312,319	267,758	452,932	140,613	0.53	632,266
KeySpan Gas East Corporation	NY	2007	1,820,046	1,438,200	931,341	506,859	1,083,879	152,538	0.30	535,236
KeySpan Gas East Corporation	NY	2008	1,924,421	1,520,339	922,741	597,598	1,101,843	179,102	0.30	539,291

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KeySpan Gas East Corporation	NY	2009	2,024,327	1,342,346	736,380	605,966	925,434	189,054	0.31	546,917
KeySpan Gas East Corporation	NY	2010	2,117,829	1,195,903	616,569	579,334	812,969	196,400	0.34	550,291
KeySpan Gas East Corporation	NY	2011	2,199,758	1,142,501	535,429	607,072	755,088	219,659	0.36	553,699
Laclede Gas Company	MO	2007	787,909	1,131,554	798,233	333,321	954,479	156,246	0.47	644,113
Laclede Gas Company	MO	2008	817,313	1,128,287	770,411	357,876	940,542	170,131	0.48	643,424
Laclede Gas Company	MO	2009	843,941	1,053,993	700,484	353,509	875,337	174,853	0.49	642,606
Laclede Gas Company	MO	2010	872,095	864,297	519,245	345,052	689,230	169,985	0.49	641,134
Laclede Gas Company	MO	2011	916,694	913,190	549,357	363,833	723,515	174,158	0.48	638,717
Louisville Gas and Electric Company	KY	2007	404,817	352,682	253,592	99,090	305,812	52,220	0.53	325,562
Louisville Gas and Electric Company	KY	2008	430,909	458,365	353,151	105,214	409,306	56,155	0.53	313,842
Louisville Gas and Electric Company	KY	2009	443,571	361,628	249,805	111,823	313,351	63,546	0.57	316,003
Louisville Gas and Electric Company	KY	2010	490,566	302,947	169,004	133,943	230,861	61,857	0.46	320,567
Louisville Gas and Electric Company	KY	2011	535,183	304,574	161,236	143,338	226,092	64,856	0.45	318,661
Madison Gas and Electric Company	WI	2007	102,538	219,059	161,304	57,755	194,585	33,281	0.58	139,133
Madison Gas and Electric Company	WI	2008	105,240	264,109	192,496	71,613	231,271	38,775	0.54	141,489
Madison Gas and Electric Company	WI	2009	112,892	200,015	130,379	69,636	167,582	37,203	0.53	142,385
Madison Gas and Electric Company	WI	2010	120,062	177,424	114,578	62,846	154,861	40,283	0.64	143,150
Madison Gas and Electric Company	WI	2011	131,894	177,711	110,897	66,814	152,370	41,473	0.62	144,050
Michigan Gas Utilities Corporation	MI	2007	134,221	220,175	167,315	52,860	195,463	28,148	0.53	164,663
Michigan Gas Utilities Corporation	MI	2008	136,516	242,961	187,039	55,922	217,993	30,954	0.55	164,351
Michigan Gas Utilities Corporation	MI	2009	136,903	192,283	133,195	59,088	163,167	29,972	0.51	164,273
Michigan Gas Utilities Corporation	MI	2010	134,390	177,435	115,179	62,256	147,873	32,694	0.53	164,792
Michigan Gas Utilities Corporation	MI	2011	137,625	161,522	99,257	62,265	132,262	33,005	0.53	165,535
Midwest Energy, Inc.	KS	2007	33,416	48,098	30,353	17,745	40,561	10,208	0.58	41,508
Midwest Energy, Inc.	KS	2008	35,288	57,466	38,956	18,510	49,880	10,924	0.59	41,699
Midwest Energy, Inc.	KS	2009	36,944	43,053	24,794	18,259	35,958	11,164	0.61	41,689
Midwest Energy, Inc.	KS	2010	38,284	46,202	27,336	18,866	39,254	11,918	0.63	41,620
Midwest Energy, Inc.	KS	2011	39,067	48,166	28,224	19,942	41,217	12,993	0.65	41,674
Midwest Natural Gas Corporation	IN	2007	10,580	21,045	14,841	6,204	18,561	3,720	0.60	14,530
Midwest Natural Gas Corporation	IN	2008	10,754	26,570	19,107	7,463	22,908	3,801	0.51	14,272
Midwest Natural Gas Corporation	IN	2009	10,834	18,888	12,098	6,790	15,936	3,838	0.57	14,092
Midwest Natural Gas Corporation	IN	2010	11,476	16,637	9,959	6,678	13,893	3,934	0.59	14,017
Midwest Natural Gas Corporation	IN	2011	12,412	15,073	8,215	6,858	12,315	4,100	0.60	13,922
Midwest Natural Gas, Inc.	WI	2007	14,910	21,319	16,058	5,261	17,607	1,549	0.29	13,969
Midwest Natural Gas, Inc.	WI	2008	15,153	23,435	18,452	4,983	20,528	2,076	0.42	14,208
Midwest Natural Gas, Inc.	WI	2009	15,188	18,115	12,383	5,732	14,816	2,433	0.42	14,374
Midwest Natural Gas, Inc.	WI	2010	15,520	17,014	11,301	5,713	13,608	2,307	0.40	14,601
Midwest Natural Gas, Inc.	WI	2011	15,977	16,253	10,630	5,623	12,962	2,332	0.41	14,791
Missouri Gas Energy	MO	2007	631,609	644,689	415,487	229,202	505,281	89,794	0.39	501,723
Missouri Gas Energy	MO	2008	640,444	738,601	502,617	235,984	604,803	102,186	0.43	500,138
Missouri Gas Energy	MO	2009	651,354	608,252	382,617	225,635	482,681	100,064	0.44	498,393
Missouri Gas Energy	MO	2010	661,596	629,669	387,716	241,953	495,484	107,768	0.45	495,789
Missouri Gas Energy	MO	2011	672,745	597,758	360,485	237,273	474,436	113,951	0.48	491,794
Mobile Gas Service Corporation	AL	2007	121,019	108,254	53,410	54,844	75,458	22,048	0.40	93,915
Mobile Gas Service Corporation	AL	2008	124,913	108,461	53,607	54,854	75,800	22,193	0.40	93,424
Mobile Gas Service Corporation	AL	2009	126,109	114,988	57,803	57,185	80,563	22,760	0.40	91,585
Mobile Gas Service Corporation	AL	2010	129,278	103,364	44,532	58,832	70,304	25,772	0.44	91,102
Mobile Gas Service Corporation	AL	2011	129,443	92,922	32,961	59,961	58,342	25,381	0.42	88,192

Schedule 2: Natural Gas LDC Data Base

A	B	C	D	E	F	G	H	I	J	K
Formula:						E-F		H-F	I/G	
Utility	State of Operation	Year	Net Plant ($000's)	Operating Revenues ($000's)	Gas Cost ($000's)	Operating Revenue- Gas Cost	Total Gas O&M ($000's)	OE -Gas Cost	Operating Ratio	Gas Customers
Mountaineer Gas Company	WV	2007	176,885	325,365	221,668	103,697	279,996	58,328	0.56	218,981
Mountaineer Gas Company	WV	2008	179,963	360,712	252,262	108,450	312,413	60,151	0.55	219,696
Mountaineer Gas Company	WV	2009	184,088	356,798	253,905	102,893	313,717	59,812	0.58	216,812
Mountaineer Gas Company	WV	2010	191,451	286,519	180,556	105,963	242,414	61,858	0.58	217,480
Mountaineer Gas Company	WV	2011	191,751	247,195	138,334	108,861	203,367	65,033	0.60	220,575
Mt. Carmel Public Utility Company	IL	2007	1,986	4,227	3,216	1,011	4,065	849	0.84	3,611
Mt. Carmel Public Utility Company	IL	2008	2,049	5,005	3,767	1,238	4,609	842	0.68	3,602
Mt. Carmel Public Utility Company	IL	2009	2,168	4,381	2,921	1,460	3,954	1,033	0.71	3,574
Mt. Carmel Public Utility Company	IL	2010	2,378	4,023	2,565	1,458	3,529	964	0.66	3,545
Mt. Carmel Public Utility Company	IL	2011	2,447	3,224	1,841	1,383	2,923	1,082	0.78	3,534
National Fuel Gas Distribution Corporation	PA	2007	287,511	351,750	195,729	156,021	298,956	103,227	0.66	211,743
National Fuel Gas Distribution Corporation	PA	2008	294,417	388,775	230,572	158,203	334,091	103,519	0.65	212,181
National Fuel Gas Distribution Corporation	PA	2009	300,607	325,122	171,025	154,097	269,417	98,392	0.64	211,714
National Fuel Gas Distribution Corporation	PA	2010	306,785	255,483	104,641	150,842	199,602	94,961	0.63	212,293
National Fuel Gas Distribution Corporation	PA	2011	312,947	248,054	93,264	154,790	189,503	96,239	0.62	212,183
New Jersey Natural Gas Company	NJ	2007	899,006	1,050,541	741,852	308,689	867,240	125,388	0.41	480,732
New Jersey Natural Gas Company	NJ	2008	947,435	1,139,038	811,420	327,618	937,362	125,942	0.38	486,089
New Jersey Natural Gas Company	NJ	2009	996,693	1,002,670	652,373	350,297	789,678	137,305	0.39	488,994
New Jersey Natural Gas Company	NJ	2010	1,074,192	989,365	642,336	347,029	777,380	135,044	0.39	493,483
New Jersey Natural Gas Company	NJ	2011	1,150,834	885,553	533,003	352,550	669,672	136,669	0.39	497,756
New York State Electric & Gas Corporation	NY	2007	498,590	470,317	304,327	165,990	362,814	58,487	0.35	256,885
New York State Electric & Gas Corporation	NY	2008	507,397	467,499	304,034	163,465	363,006	58,972	0.36	258,822
New York State Electric & Gas Corporation	NY	2009	505,456	433,728	254,411	179,317	328,101	73,690	0.41	260,165
New York State Electric & Gas Corporation	NY	2010	508,313	371,504	188,629	182,875	268,463	79,834	0.44	261,183
New York State Electric & Gas Corporation	NY	2011	491,541	370,850	178,602	192,248	277,562	98,960	0.51	260,899
Niagara Mohawk Power Corporation	NY	2007	1,086,610	885,061	591,286	293,775	707,745	116,459	0.40	570,902
Niagara Mohawk Power Corporation	NY	2008	1,117,232	909,751	616,152	293,599	749,970	133,818	0.46	575,428
Niagara Mohawk Power Corporation	NY	2009	1,147,464	783,670	470,429	313,241	631,882	161,453	0.52	579,682
Niagara Mohawk Power Corporation	NY	2010	1,176,982	746,702	373,247	373,455	576,359	203,112	0.54	582,927
Niagara Mohawk Power Corporation	NY	2011	1,201,146	729,181	353,678	375,503	543,954	190,276	0.51	585,749
North Shore Gas Company	IL	2007	244,379	285,783	205,386	80,397	246,577	41,191	0.51	157,881
North Shore Gas Company	IL	2008	245,488	312,870	240,893	71,977	288,912	48,019	0.67	158,253
North Shore Gas Company	IL	2009	247,648	228,210	158,229	69,981	208,289	50,060	0.72	158,009
North Shore Gas Company	IL	2010	250,738	211,260	126,699	84,561	181,766	55,067	0.65	157,852
North Shore Gas Company	IL	2011	250,518	201,423	117,665	83,758	169,206	51,541	0.62	158,243
Northeast Ohio Natural Gas Corp.	OH	2007	12,173	16,253	12,422	3,831	14,760	2,338	0.61	9,287
Northeast Ohio Natural Gas Corp.	OH	2008	18,705	27,030	20,281	6,749	24,347	4,066	0.60	14,710
Northeast Ohio Natural Gas Corp.	OH	2009	18,543	21,107	14,755	6,352	17,854	3,099	0.49	14,771
Northeast Ohio Natural Gas Corp.	OH	2010	20,317	16,711	9,462	7,249	13,135	3,673	0.51	15,761
Northeast Ohio Natural Gas Corp.	OH	2011	24,224	17,172	10,885	6,287	14,896	4,011	0.64	15,327
Northern Illinois Gas Company	IL	2007	1,844,983	2,627,495	1,906,488	721,007	2,166,857	260,369	0.36	2,162,712
Northern Illinois Gas Company	IL	2008	1,906,334	3,206,870	2,427,791	779,079	2,721,371	293,580	0.38	2,173,440
Northern Illinois Gas Company	IL	2009	1,933,069	2,140,797	1,345,706	795,091	1,644,569	298,863	0.38	2,172,724
Northern Illinois Gas Company	IL	2010	1,942,952	2,204,423	1,364,057	840,366	1,661,161	297,104	0.35	2,177,015
Northern Illinois Gas Company	IL	2011	1,968,479	2,063,775	1,260,398	803,377	1,555,029	294,631	0.37	2,184,884
NSTAR Gas Company	MA	2007	417,993	556,877	391,978	164,899	471,661	79,683	0.48	259,378
NSTAR Gas Company	MA	2008	440,564	548,189	389,237	158,952	466,543	77,306	0.49	260,419
NSTAR Gas Company	MA	2009	467,381	475,992	317,642	158,350	389,373	71,731	0.45	266,726

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Utility	State of Operation	Year	Net Plant ($000's)	Operating Revenues ($000's)	Gas Cost ($000's)	Operating Revenue- Gas Cost	Total Gas O&M ($000's)	OE -Gas Cost	Operating Ratio	Gas Customers
NSTAR Gas Company	MA	2010	490,252	427,745	258,240	169,505	340,397	82,157	0.48	268,312
NSTAR Gas Company	MA	2011	527,734	425,869	251,684	174,185	339,474	87,790	0.50	270,254
Ohio Gas Company	OH	2007	30,226	16,870	18	16,852	7,322	7,304	0.43	46,385
Ohio Gas Company	OH	2008	30,356	17,128	12	17,116	7,701	7,689	0.45	46,440
Ohio Gas Company	OH	2009	29,937	16,686	1	16,685	8,197	8,196	0.49	46,418
Ohio Gas Company	OH	2010	30,601	16,000	0	16,000	7,979	7,979	0.50	46,498
Ohio Gas Company	OH	2011	35,714	16,932	0	16,932	7,633	7,633	0.45	47,024
Oklahoma Natural Gas Company	OK	2007	823,741	864,497	595,310	269,187	751,330	156,020	0.58	843,946
Oklahoma Natural Gas Company	OK	2008	873,579	906,710	621,619	285,091	772,072	150,453	0.53	847,444
Oklahoma Natural Gas Company	OK	2009	910,214	833,095	517,668	315,427	674,592	156,924	0.50	848,684
Oklahoma Natural Gas Company	OK	2010	1,001,227	780,894	435,538	345,356	608,032	172,494	0.50	840,361
Oklahoma Natural Gas Company	OK	2011	1,067,283	726,521	379,575	346,946	559,878	180,303	0.52	849,322
Pacific Gas and Electric Company	CA	2007	3,671,724	3,872,635	1,856,139	2,016,496	2,987,977	1,131,838	0.56	4,305,091
Pacific Gas and Electric Company	CA	2008	3,887,882	4,061,504	2,008,576	2,052,928	3,139,930	1,131,354	0.55	4,356,537
Pacific Gas and Electric Company	CA	2009	4,048,379	3,273,991	1,151,106	2,122,885	2,352,075	1,200,969	0.57	4,309,570
Pacific Gas and Electric Company	CA	2010	4,388,936	3,341,762	1,156,484	2,185,278	2,523,860	1,367,376	0.63	4,305,935
Pacific Gas and Electric Company	CA	2011	4,659,278	3,490,389	1,163,132	2,327,257	2,943,606	1,780,474	0.77	4,346,996
PECO Energy Company	PA	2007	1,554,896	838,818	618,531	220,287	724,705	106,174	0.48	481,422
PECO Energy Company	PA	2008	1,603,078	821,727	608,730	212,997	727,290	118,560	0.56	483,457
PECO Energy Company	PA	2009	1,649,790	759,620	473,761	285,859	579,792	106,031	0.37	486,063
PECO Energy Company	PA	2010	1,701,588	686,770	402,528	284,242	511,064	108,536	0.38	487,844
PECO Energy Company	PA	2011	1,761,923	613,046	318,305	294,741	428,182	109,877	0.37	493,634
Peoples Gas Light and Coke Company	IL	2007	1,538,505	1,487,288	899,938	587,350	1,260,150	360,212	0.61	830,184
Peoples Gas Light and Coke Company	IL	2008	1,592,079	1,586,209	1,062,580	523,629	1,410,463	347,883	0.66	829,776
Peoples Gas Light and Coke Company	IL	2009	1,608,318	1,148,747	655,954	492,793	993,028	337,074	0.68	822,105
Peoples Gas Light and Coke Company	IL	2010	1,736,155	1,071,526	543,061	528,465	867,762	324,701	0.61	819,154
Peoples Gas Light and Coke Company	IL	2011	1,895,545	1,029,687	508,375	521,312	813,559	305,184	0.59	827,576
Peoples Gas System	FL	2007	556,101	593,029	389,921	203,108	463,245	73,324	0.36	334,628
Peoples Gas System	FL	2008	583,330	680,920	476,590	204,330	546,371	69,781	0.34	335,121
Peoples Gas System	FL	2009	588,006	461,986	244,518	217,468	324,463	79,945	0.37	334,175
Peoples Gas System	FL	2010	605,507	521,442	284,840	236,602	367,687	82,847	0.35	335,966
Peoples Gas System	FL	2011	623,708	444,085	211,250	232,835	294,579	83,329	0.36	338,823
Philadelphia Gas Works Co.	PA	2007	1,042,998	871,892	553,914	317,978	778,752	224,838	0.71	498,249
Philadelphia Gas Works Co.	PA	2008	1,069,055	885,956	544,907	341,049	779,639	234,732	0.69	498,255
Philadelphia Gas Works Co.	PA	2009	1,078,349	823,141	462,689	360,452	704,701	242,012	0.67	495,980
Philadelphia Gas Works Co.	PA	2010	1,096,024	749,191	357,869	391,322	609,162	251,293	0.64	497,247
Philadelphia Gas Works Co.	PA	2011	1,113,582	705,084	305,457	399,627	555,335	249,878	0.63	498,890
Pike County Light and Power Company	PA	2007	1,354	1,875	1,479	396	1,860	381	0.96	1,172
Pike County Light and Power Company	PA	2008	1,535	1,678	1,356	322	1,707	351	1.09	1,192
Pike County Light and Power Company	PA	2009	1,553	1,691	1,371	320	1,597	226	0.71	1,192
Pike County Light and Power Company	PA	2010	1,598	1,274	546	728	807	261	0.36	1,198
Pike County Light and Power Company	PA	2011	1,803	1,341	776	565	1,121	345	0.61	1,192
Pike Natural Gas Co	OH	2007	2,800	10,587	8,359	2,228	10,276	1,917	0.86	7,150
Pike Natural Gas Co	OH	2008	2,635	11,655	9,311	2,344	11,267	1,956	0.83	7,103
Pike Natural Gas Co	OH	2009	2,498	8,592	6,333	2,259	8,230	1,897	0.84	7,126
Pike Natural Gas Co	OH	2010	2,326	7,163	4,831	2,332	6,733	1,902	0.82	7,140
Pike Natural Gas Co	OH	2011	2,385	8,087	5,594	2,493	7,614	2,020	0.81	7,109
Pivotal Utility Holdings, Inc.	MD	2007	7,871	11,661	8,960	2,701	10,804	1,844	0.68	5,998

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Utility	**State of Operation**	**Year**	**Net Plant ($000's)**	**Operating Revenues ($000's)**	**Gas Cost ($000's)**	**Operating Revenue- Gas Cost**	**Total Gas O&M ($000's)**	**OE -Gas Cost**	**Operating Ratio**	**Gas Customers**
Pivotal Utility Holdings, Inc.	**MD**	**2008**	7,923	14,733	11,836	2,897	13,623	1,787	0.62	6,017
Pivotal Utility Holdings, Inc.	**MD**	**2009**	8,277	10,443	7,417	3,026	9,353	1,936	0.64	6,098
Pivotal Utility Holdings, Inc.	**MD**	**2010**	8,574	10,325	7,153	3,172	9,203	2,050	0.65	6,055
Pivotal Utility Holdings, Inc.	**MD**	**2011**	8,838	10,003	6,807	3,196	8,707	1,900	0.59	6,168
Pivotal Utility Holdings, Inc.	**NJ**	**2007**	572,395	512,103	355,392	156,711	422,573	67,181	0.43	271,668
Pivotal Utility Holdings, Inc.	**NJ**	**2008**	593,453	523,481	372,821	150,660	443,377	70,556	0.47	273,003
Pivotal Utility Holdings, Inc.	**NJ**	**2009**	630,795	453,206	301,841	151,365	377,306	75,465	0.50	273,281
Pivotal Utility Holdings, Inc.	**NJ**	**2010**	682,537	397,098	239,536	157,562	313,543	74,007	0.47	274,286
Pivotal Utility Holdings, Inc.	**NJ**	**2011**	705,705	387,918	223,532	164,386	294,091	70,559	0.43	275,613
Public Service Company of Colorado	**CO**	**2007**	1,207,375	1,191,008	834,877	356,131	979,157	144,280	0.41	1,264,890
Public Service Company of Colorado	**CO**	**2008**	1,207,248	1,378,985	996,933	382,052	1,147,727	150,794	0.39	1,279,345
Public Service Company of Colorado	**CO**	**2009**	1,396,977	1,099,342	716,768	382,574	886,131	169,363	0.44	1,293,575
Public Service Company of Colorado	**CO**	**2010**	1,329,428	1,081,067	690,408	390,659	867,430	177,022	0.45	1,302,243
Public Service Company of Colorado	**CO**	**2011**	1,444,912	1,093,630	697,442	396,188	888,974	191,532	0.48	1,310,531
Public Service Company of North Carolina, Incorporated	**NC**	**2007**	1,127,219	577,314	379,163	198,151	461,801	82,638	0.42	444,368
Public Service Company of North Carolina, Incorporated	**NC**	**2008**	1,186,656	670,276	458,597	211,679	544,650	86,053	0.41	458,407
Public Service Company of North Carolina, Incorporated	**NC**	**2009**	1,199,770	528,321	309,985	218,336	391,825	81,840	0.37	465,796
Public Service Company of North Carolina, Incorporated	**NC**	**2010**	1,241,757	537,836	315,440	222,396	399,314	83,874	0.38	472,605
Public Service Company of North Carolina, Incorporated	**NC**	**2011**	1,287,975	453,003	227,551	225,452	310,300	82,749	0.37	480,280
Public Service Electric and Gas Company	**NJ**	**2007**	2,534,013	3,027,323	2,160,313	867,010	2,596,372	436,059	0.50	1,732,227
Public Service Electric and Gas Company	**NJ**	**2008**	2,672,541	3,144,537	2,301,784	842,753	2,726,366	424,582	0.50	1,742,029
Public Service Electric and Gas Company	**NJ**	**2009**	2,830,176	2,764,661	1,879,844	884,817	2,359,244	479,400	0.54	1,774,057
Public Service Electric and Gas Company	**NJ**	**2010**	3,047,696	2,463,974	1,588,966	875,008	2,042,680	453,714	0.52	1,778,357
Public Service Electric and Gas Company	**NJ**	**2011**	3,157,141	2,207,607	1,282,118	925,489	1,715,937	433,819	0.47	1,779,350
Puget Sound Energy, Inc.	**WA**	**2007**	1,572,750	1,208,029	762,894	445,135	884,079	121,185	0.27	721,999
Puget Sound Energy, Inc.	**WA**	**2008**	1,683,311	1,216,868	738,823	478,045	876,403	137,580	0.29	737,842
Puget Sound Energy, Inc.	**WA**	**2009**	1,772,300	1,224,745	719,697	505,048	869,732	150,035	0.30	746,536
Puget Sound Energy, Inc.	**WA**	**2010**	1,808,855	1,011,531	536,809	474,722	684,131	147,322	0.31	750,806
Puget Sound Energy, Inc.	**WA**	**2011**	1,835,029	1,168,850	622,580	546,270	779,152	156,572	0.29	756,706
Rochester Gas and Electric Corporation	**NY**	**2007**	382,413	421,487	284,106	137,381	338,143	54,037	0.39	296,471
Rochester Gas and Electric Corporation	**NY**	**2008**	391,401	432,824	282,760	150,064	342,113	59,353	0.40	297,778
Rochester Gas and Electric Corporation	**NY**	**2009**	388,724	360,686	211,930	148,756	280,465	68,535	0.46	299,130
Rochester Gas and Electric Corporation	**NY**	**2010**	395,109	318,183	166,707	151,476	236,028	69,321	0.46	301,290
Rochester Gas and Electric Corporation	**NY**	**2011**	404,633	310,551	148,792	161,759	224,249	75,457	0.47	303,038
San Diego Gas & Electric Co.	**CA**	**2007**	687,003	677,604	392,944	284,660	574,516	181,572	0.64	835,028
San Diego Gas & Electric Co.	**CA**	**2008**	640,252	700,031	415,865	284,166	587,102	171,237	0.60	838,855
San Diego Gas & Electric Co.	**CA**	**2009**	673,840	520,114	205,535	314,579	404,337	198,802	0.63	842,444
San Diego Gas & Electric Co.	**CA**	**2010**	725,911	542,043	217,233	324,810	401,871	184,638	0.57	847,306
San Diego Gas & Electric Co.	**CA**	**2011**	759,628	549,593	226,333	323,260	430,880	204,547	0.63	852,135
South Carolina Electric & Gas Co.	**SC**	**2007**	448,610	519,100	389,243	129,857	445,894	56,651	0.44	299,157
South Carolina Electric & Gas Co.	**SC**	**2008**	490,149	567,844	430,357	137,487	492,922	62,565	0.46	304,089
South Carolina Electric & Gas Co.	**SC**	**2009**	525,576	420,105	278,186	141,919	339,030	60,844	0.43	307,617
South Carolina Electric & Gas Co.	**SC**	**2010**	549,539	441,619	289,224	152,395	349,949	60,725	0.40	310,942
South Carolina Electric & Gas Co.	**SC**	**2011**	575,519	387,383	241,541	145,842	304,773	63,232	0.43	314,327
South Jersey Gas Company	**NJ**	**2007**	847,691	630,547	456,003	174,544	511,116	55,113	0.32	364,361
South Jersey Gas Company	**NJ**	**2008**	876,582	568,046	387,543	180,503	447,085	59,542	0.33	337,146
South Jersey Gas Company	**NJ**	**2009**	961,165	484,066	299,341	184,725	364,462	65,121	0.35	341,284
South Jersey Gas Company	**NJ**	**2010**	1,046,804	475,982	273,915	202,067	344,663	70,748	0.35	345,108

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Utility	**State of Operation**	**Year**	**Net Plant ($000's)**	**Operating Revenues ($000's)**	**Gas Cost ($000's)**	**Operating Revenue- Gas Cost**	**Total Gas O&M ($000's)**	**OE -Gas Cost**	**Operating Ratio**	**Gas Customers**
South Jersey Gas Company	**NJ**	**2011**	1,158,029	412,449	194,854	217,595	268,565	73,711	0.34	348,878
Southern California Gas Company	**CA**	**2007**	4,861,739	4,325,048	2,423,789	1,901,259	3,541,982	1,118,193	0.59	5,445,996
Southern California Gas Company	**CA**	**2008**	5,130,697	4,759,440	2,845,383	1,914,057	3,976,673	1,131,290	0.59	5,467,401
Southern California Gas Company	**CA**	**2009**	5,431,663	3,424,361	1,349,322	2,075,039	2,584,588	1,235,266	0.60	5,494,958
Southern California Gas Company	**CA**	**2010**	5,767,477	3,833,844	1,703,704	2,130,140	2,933,870	1,230,166	0.58	5,516,867
Southern California Gas Company	**CA**	**2011**	6,332,773	3,815,629	1,573,416	2,242,213	2,919,864	1,346,448	0.60	5,549,399
Southern Connecticut Gas Company	**CT**	**2007**	612,085	396,556	236,415	160,141	309,020	72,605	0.45	174,587
Southern Connecticut Gas Company	**CT**	**2008**	631,304	421,911	259,253	162,658	333,710	74,457	0.46	175,040
Southern Connecticut Gas Company	**CT**	**2009**	625,024	332,877	177,675	155,202	259,462	81,787	0.53	175,717
Southern Connecticut Gas Company	**CT**	**2010**	498,034	354,271	194,339	159,932	266,527	72,188	0.45	175,517
Southern Connecticut Gas Company	**CT**	**2011**	512,601	358,204	197,103	161,101	274,509	77,406	0.48	177,267
Southern Indiana Gas and Electric Company, Inc.	**IN**	**2007**	112,073	133,035	89,766	43,269	110,944	21,178	0.49	111,163
Southern Indiana Gas and Electric Company, Inc.	**IN**	**2008**	120,291	160,665	116,182	44,483	139,211	23,029	0.52	110,617
Southern Indiana Gas and Electric Company, Inc.	**IN**	**2009**	135,986	111,663	67,703	43,960	92,640	24,937	0.57	109,974
Southern Indiana Gas and Electric Company, Inc.	**IN**	**2010**	148,142	106,755	61,079	45,676	88,886	27,807	0.61	110,009
Southern Indiana Gas and Electric Company, Inc.	**IN**	**2011**	151,774	96,384	49,067	47,317	75,932	26,865	0.57	109,864
St. Joe Natural Gas Co, Inc.	**FL**	**2007**	3,039	1,747	675	1,072	1,507	832	0.78	3,099
St. Joe Natural Gas Co, Inc.	**FL**	**2008**	2,867	2,484	1,017	1,467	1,923	906	0.62	3,059
St. Joe Natural Gas Co, Inc.	**FL**	**2009**	3,016	2,293	753	1,540	1,660	907	0.59	2,961
St. Joe Natural Gas Co, Inc.	**FL**	**2010**	2,922	2,431	752	1,679	1,745	993	0.59	2,961
St. Joe Natural Gas Co, Inc.	**FL**	**2011**	2,763	2,234	682	1,552	1,567	885	0.57	2,917
St. Lawrence Gas Company, Inc.	**NY**	**2007**	23,611	47,831	35,395	12,436	41,941	6,546	0.53	15,359
St. Lawrence Gas Company, Inc.	**NY**	**2008**	23,798	51,500	39,091	12,409	46,327	7,236	0.58	15,314
St. Lawrence Gas Company, Inc.	**NY**	**2009**	24,764	42,617	29,512	13,105	38,541	9,029	0.69	15,457
St. Lawrence Gas Company, Inc.	**NY**	**2010**	25,924	40,890	26,382	14,508	34,666	8,284	0.57	15,507
St. Lawrence Gas Company, Inc.	**NY**	**2011**	27,597	40,015	25,893	14,122	34,041	8,148	0.58	15,506
Superior Water, Light and Power Company	**WI**	**2007**	9,372	21,821	15,235	6,586	19,649	4,414	0.67	12,105
Superior Water, Light and Power Company	**WI**	**2008**	9,386	25,403	18,538	6,865	23,027	4,489	0.65	12,157
Superior Water, Light and Power Company	**WI**	**2009**	9,438	17,592	11,098	6,494	15,452	4,354	0.67	12,260
Superior Water, Light and Power Company	**WI**	**2010**	9,279	17,102	10,858	6,244	15,247	4,389	0.70	12,323
Superior Water, Light and Power Company	**WI**	**2011**	9,240	17,476	10,411	7,065	14,996	4,585	0.65	12,323
Texas Gas Service Company	**TX**	**2007**	473,112	420,887	272,988	147,899	354,236	81,248	0.55	587,918
Texas Gas Service Company	**TX**	**2008**	502,894	433,148	284,946	148,202	365,293	80,347	0.54	589,637
Texas Gas Service Company	**TX**	**2009**	527,901	325,580	172,152	153,428	261,954	89,802	0.59	604,855
Texas Gas Service Company	**TX**	**2010**	566,960	358,094	208,354	149,740	300,991	92,637	0.62	613,874
Texas Gas Service Company	**TX**	**2011**	637,444	310,637	152,436	158,201	250,738	98,302	0.62	621,154
UGI Central Penn Gas, Inc.	**PA**	**2007**	217,918	189,400	118,792	70,608	162,133	43,341	0.61	77,138
UGI Central Penn Gas, Inc.	**PA**	**2008**	243,717	193,042	119,679	73,363	165,076	45,397	0.62	76,517
UGI Central Penn Gas, Inc.	**PA**	**2009**	249,184	185,322	98,000	87,322	136,790	38,790	0.44	75,802
UGI Central Penn Gas, Inc.	**PA**	**2010**	258,444	156,194	78,518	77,676	114,499	35,981	0.46	75,727
UGI Central Penn Gas, Inc.	**PA**	**2011**	262,086	148,186	71,821	76,365	109,265	37,444	0.49	76,078
UGI Utilities, Inc.	**PA**	**2007**	714,439	618,390	407,366	211,024	494,453	87,087	0.41	323,046
UGI Utilities, Inc.	**PA**	**2008**	740,534	626,348	417,610	208,738	507,440	89,830	0.43	329,947
UGI Utilities, Inc.	**PA**	**2009**	754,797	611,218	405,453	205,765	490,759	85,306	0.41	335,286
UGI Utilities, Inc.	**PA**	**2010**	776,071	573,290	362,756	210,534	444,669	81,913	0.39	340,048
UGI Utilities, Inc.	**PA**	**2011**	816,038	534,103	323,682	210,421	409,651	85,969	0.41	350,802
Valley Energy Inc.	**NY**	**2007**	2,481	2,584	1,992	592	2,466	474	0.80	1,567
Valley Energy Inc.	**NY**	**2008**	2,446	3,268	2,387	881	2,810	423	0.48	1,598

Schedule 2: Natural Gas LDC Data Base

A	B	C	D	E	F	G	H	I	J	K
Formula:						E-F		H-F	I/G	
Utility	State of Operation	Year	Net Plant ($000's)	Operating Revenues ($000's)	Gas Cost ($000's)	Operating Revenue- Gas Cost	Total Gas O&M ($000's)	OE -Gas Cost	Operating Ratio	Gas Customers
Valley Energy Inc.	NY	2009	2,446	2,516	1,673	843	2,098	425	0.50	1,645
Valley Energy Inc.	NY	2010	2,347	2,005	1,165	840	1,606	441	0.53	1,678
Valley Energy Inc.	NY	2011	2,343	1,994	1,113	881	1,552	439	0.50	1,703
Valley Energy Inc.	PA	2007	13,088	9,378	5,934	3,444	8,013	2,079	0.60	5,442
Valley Energy Inc.	PA	2008	13,245	10,992	7,233	3,759	9,144	1,911	0.51	5,540
Valley Energy Inc.	PA	2009	13,197	9,434	5,869	3,565	7,918	2,049	0.57	5,721
Valley Energy Inc.	PA	2010	13,263	8,070	4,297	3,773	6,229	1,932	0.51	5,867
Valley Energy Inc.	PA	2011	13,538	8,616	4,610	4,006	6,745	2,135	0.53	5,958
Vectren Energy Delivery of Ohio, Inc.	OH	2007	454,981	374,320	246,249	128,071	308,510	62,261	0.49	315,990
Vectren Energy Delivery of Ohio, Inc.	OH	2008	459,222	408,098	274,066	134,032	336,692	62,626	0.47	315,102
Vectren Energy Delivery of Ohio, Inc.	OH	2009	485,686	291,259	157,978	133,281	226,219	68,241	0.51	312,320
Vectren Energy Delivery of Ohio, Inc.	OH	2010	509,713	224,226	90,569	133,657	159,040	68,471	0.51	310,701
Vectren Energy Delivery of Ohio, Inc.	OH	2011	539,827	139,606	13,180	126,426	78,497	65,317	0.52	310,404
Vermont Gas Systems, Inc.	VT	2007	91,162	106,588	79,960	26,628	90,096	10,136	0.38	39,900
Vermont Gas Systems, Inc.	VT	2008	97,798	116,339	86,253	30,086	97,636	11,383	0.38	40,945
Vermont Gas Systems, Inc.	VT	2009	104,728	116,084	81,900	34,184	95,592	13,692	0.40	42,364
Vermont Gas Systems, Inc.	VT	2010	109,314	94,527	61,759	32,768	74,888	13,129	0.40	43,223
Vermont Gas Systems, Inc.	VT	2011	114,095	99,901	64,173	35,728	78,504	14,331	0.40	44,132
Virginia Natural Gas, Inc.	VA	2007	405,483	369,034	253,237	115,797	298,918	45,681	0.39	269,299
Virginia Natural Gas, Inc.	VA	2008	481,076	387,327	270,839	116,488	313,834	42,995	0.37	271,407
Virginia Natural Gas, Inc.	VA	2009	749,565	328,512	205,916	122,596	251,549	45,633	0.37	272,740
Virginia Natural Gas, Inc.	VA	2010	778,186	347,622	203,488	144,134	254,544	51,056	0.35	275,184
Virginia Natural Gas, Inc.	VA	2011	831,336	307,116	162,272	144,844	210,550	48,278	0.33	278,175
Wisconsin Gas LLC	WI	2007	555,445	871,985	610,193	261,792	725,628	115,435	0.44	588,266
Wisconsin Gas LLC	WI	2008	591,145	988,564	696,117	292,447	833,927	137,810	0.47	591,898
Wisconsin Gas LLC	WI	2009	595,077	804,724	524,016	280,708	659,921	135,905	0.48	594,702
Wisconsin Gas LLC	WI	2010	631,452	708,584	437,890	270,694	587,300	149,410	0.55	597,326
Wisconsin Gas LLC	WI	2011	683,724	703,849	424,838	279,011	579,155	154,317	0.55	599,478
Wisconsin Power and Light Company	WI	2007	109,928	266,837	176,201	90,636	205,654	29,453	0.32	174,853
Wisconsin Power and Light Company	WI	2008	190,512	302,151	214,726	87,425	244,750	30,024	0.34	176,649
Wisconsin Power and Light Company	WI	2009	206,071	217,671	139,420	78,251	171,713	32,293	0.41	176,649
Wisconsin Power and Light Company	WI	2010	218,302	206,321	125,896	80,425	159,001	33,105	0.41	178,311
Wisconsin Power and Light Company	WI	2011	223,451	200,415	120,367	80,048	154,863	34,496	0.43	180,252
Wyoming Gas Company	WY	2007	5,996	8,642	6,291	2,351	8,046	1,755	0.75	6,735
Wyoming Gas Company	WY	2008	6,612	9,433	6,637	2,796	8,690	2,053	0.73	6,778
Wyoming Gas Company	WY	2009	6,816	8,953	5,958	2,995	7,993	2,035	0.68	6,858
Wyoming Gas Company	WY	2010	6,998	7,755	4,147	3,608	6,384	2,237	0.62	6,877
Wyoming Gas Company	WY	2011	7,115	8,329	4,501	3,828	6,779	2,278	0.60	6,881
Yankee Gas Services Company	CT	2007	706,476	514,182	319,968	194,214	405,710	85,742	0.44	202,743
Yankee Gas Services Company	CT	2008	725,765	577,390	361,631	215,759	455,039	93,408	0.43	204,835
Yankee Gas Services Company	CT	2009	754,633	449,495	228,812	220,683	339,442	110,630	0.50	206,438
Yankee Gas Services Company	CT	2010	822,234	434,277	209,054	225,223	309,331	100,277	0.45	205,886
Yankee Gas Services Company	CT	2011	894,853	430,799	194,104	236,695	299,651	105,547	0.45	207,753

Schedule 2: Natural Gas LDC Data Base

A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
Alabama Gas Corporation	**AL**	**2007**	10,475	269	10,744	5,897	34	27	42	1.0000	0.56299	67,110	220,142	287,253	
Alabama Gas Corporation	**AL**	**2008**	10,672	269	10,941	5,976	35	28	41	0.9731	0.55995	69,595	220,142	289,737	1.0086
Alabama Gas Corporation	**AL**	**2009**	10,841	248	11,089	6,040	35	27	40	0.9541	0.55713	71,153	215,873	287,026	0.9906
Alabama Gas Corporation	**AL**	**2010**	10,866	251	11,116	6,057	35	28	39	0.9369	0.55742	71,672	210,794	282,465	0.9841
Alabama Gas Corporation	**AL**	**2011**	10,940	237	11,177	6,071	36	30	38	0.9111	0.55491	73,777	205,989	279,766	0.9904
Atlanta Gas Light Company	**GA**	**2007**	30,281	1,110	31,391	21,399	24	39	50	1.1824	0.70668	141,104	1,697,937	1,839,040	
Atlanta Gas Light Company	**GA**	**2008**	30,647	1,109	31,756	21,670	25	33	49	1.1678	0.70708	142,329	1,698,821	1,841,151	1.0011
Atlanta Gas Light Company	**GA**	**2009**	30,890	1,003	31,893	21,839	25	35	47	1.1309	0.70699	143,211	1,561,057	1,704,268	0.9257
Atlanta Gas Light Company	**GA**	**2010**	30,994	1,007	32,000	21,919	26	33	47	1.1259	0.70722	141,524	1,564,920	1,706,445	1.0013
Atlanta Gas Light Company	**GA**	**2011**	31,127	1,018	32,144	21,996	27	34	47	1.1194	0.70668	141,912	1,614,412	1,756,324	1.0292
Baltimore Gas and Electric Company	**MD**	**2007**	6,832	166	6,998	3,251	33	35	92	2.1989	0.47585	97,784	429,352	527,137	
Baltimore Gas and Electric Company	**MD**	**2008**	6,883	166	7,049	3,288	34	36	92	2.1923	0.47770	97,960	429,352	527,312	1.0003
Baltimore Gas and Electric Company	**MD**	**2009**	6,905	165	7,070	3,311	34	37	92	2.1923	0.47951	97,645	418,000	515,645	0.9779
Baltimore Gas and Electric Company	**MD**	**2010**	6,951	164	7,115	3,338	35	39	92	2.1842	0.48022	98,742	416,586	515,327	0.9994
Baltimore Gas and Electric Company	**MD**	**2011**	6,995	164	7,159	3,375	35	40	91	2.1727	0.48249	98,843	416,649	515,492	1.0003
Berkshire Gas Company	**MA**	**2007**	737	0	737	332	36		48	1.1460	0.45047	5,899	0	5,899	
Berkshire Gas Company	**MA**	**2008**	738	0	738	333	37		48	1.1498	0.45122	6,073	0	6,073	1.0295
Berkshire Gas Company	**MA**	**2009**	738	0	738	334	37		49	1.1585	0.45257	6,068	0	6,068	0.9991
Berkshire Gas Company	**MA**	**2010**	740	0	740	334	38		49	1.1568	0.45135	6,147	0	6,147	1.0131
Berkshire Gas Company	**MA**	**2011**	744	0	744	338	38		49	1.1601	0.45430	6,151	0	6,151	1.0007
Bluefield Gas Company	**WV**	**2007**	105	0	105	27	35		33	0.7804	0.26150	1,321	0	1,321	
Bluefield Gas Company	**WV**	**2008**	105	0	105	28	36		35	0.8352	0.26375	1,320	0	1,320	0.9995
Bluefield Gas Company	**WV**	**2009**	105	0	105	28	36		34	0.8007	0.26683	1,318	0	1,318	0.9988
Bluefield Gas Company	**WV**	**2010**	106	0	106	29	37		33	0.7952	0.27186	1,319	0	1,319	1.0006
Bluefield Gas Company	**WV**	**2011**	106	0	106	29	38		33	0.7838	0.27265	1,320	0	1,320	1.0009
Boston Gas Company	**MA**	**2007**	6,219	6	6,226	1,352	48	39	95	2.2530	0.21732	120,000	9,215	129,215	
Boston Gas Company	**MA**	**2008**	6,247	6	6,253	1,355	48	40	98	2.3434	0.21700	120,481	9,215	129,697	1.0037
Boston Gas Company	**MA**	**2009**	6,264	6	6,271	1,358	48	41	96	2.2948	0.21677	120,961	9,215	130,177	1.0037
Boston Gas Company	**MA**	**2010**	6,282	6	6,288	1,360	48	42	97	2.2995	0.21657	121,488	9,179	130,667	1.0038
Boston Gas Company	**MA**	**2011**	6,292	6	6,299	1,361	48	43	106	2.5227	0.21634	121,802	9,179	130,982	1.0024
Brainard Gas Corp.	**OH**	**2007**	17	0	17	13	10		5	0.1205	0.76471	38	0	38	
Brainard Gas Corp.	**OH**	**2008**	18	0	18	13	11		5	0.1297	0.72222	45	0	45	1.1654
Brainard Gas Corp.	**OH**	**2009**	18	0	18	13	12		7	0.1773	0.72222	45	0	45	1.0000
Brainard Gas Corp.	**OH**	**2010**	18	0	18	13	13		8	0.1998	0.72222	45	0	45	1.0000
Brainard Gas Corp.	**OH**	**2011**	18	0	18	13	14		9	0.2170	0.72222	45	0	45	1.0000
Central Hudson Gas & Electric Corporation	**NY**	**2007**	1,156	164	1,320	463	33	42	55	1.3208	0.40052	9,578	85,554	95,132	
Central Hudson Gas & Electric Corporation	**NY**	**2008**	1,163	164	1,327	467	34	43	56	1.3308	0.40155	9,601	85,554	95,155	1.0002
Central Hudson Gas & Electric Corporation	**NY**	**2009**	1,168	164	1,332	465	35	44	56	1.3292	0.39812	9,679	85,554	95,232	1.0008
Central Hudson Gas & Electric Corporation	**NY**	**2010**	1,177	164	1,341	472	36	45	56	1.3307	0.40102	9,698	86,641	96,340	1.0116
Central Hudson Gas & Electric Corporation	**NY**	**2011**	1,185	164	1,349	474	35	46	56	1.3312	0.40041	9,838	86,641	96,479	1.0014
Chattanooga Gas Company	**TN**	**2007**	1,557	7	1,564	918	25	15	39	0.9344	0.58960	12,184	9,037	21,221	
Chattanooga Gas Company	**TN**	**2008**	1,582	7	1,589	934	26	16	39	0.9190	0.59039	12,257	9,037	21,294	1.0034
Chattanooga Gas Company	**TN**	**2009**	1,583	7	1,590	938	26	17	39	0.9220	0.59255	12,162	9,037	21,200	0.9956
Chattanooga Gas Company	**TN**	**2010**	1,592	7	1,599	941	27	19	39	0.9195	0.59101	12,191	8,673	20,864	0.9842
Chattanooga Gas Company	**TN**	**2011**	1,593	7	1,600	945	28	19	39	0.9245	0.59348	11,728	8,415	20,144	0.9655
Chesapeake Utilities Corporation	**MD**	**2007**	281	0	281	136	26		44	1.0409	0.48460	1,542	0	1,542	
Chesapeake Utilities Corporation	**MD**	**2008**	284	0	284	141	26		43	1.0355	0.49478	1,538	0	1,538	0.9972
Chesapeake Utilities Corporation	**MD**	**2009**	293	0	293	143	25		42	1.0065	0.48829	1,660	0	1,660	1.0791
Chesapeake Utilities Corporation	**MD**	**2010**	294	0	294	144	26		42	1.0009	0.48976	1,652	0	1,652	0.9953
Chesapeake Utilities Corporation	**MD**	**2011**	293	0	293	144	26		42	1.0119	0.49080	1,656	0	1,656	1.0024
Cheyenne Light, Fuel and Power Company	**WY**	**2007**	730	29	759	558	24	50	43	1.0359	0.76438	2,825	13,168	15,992	
Cheyenne Light, Fuel and Power Company	**WY**	**2008**	743	30	773	569	25	52	43	1.0256	0.76581	2,849	13,408	16,256	1.0165
Cheyenne Light, Fuel and Power Company	**WY**	**2009**	745	30	775	571	26	50	43	1.0319	0.76644	2,851	13,408	16,258	1.0001
Cheyenne Light, Fuel and Power Company	**WY**	**2010**	752	30	782	577	26	51	44	1.0389	0.76715	2,864	13,408	16,272	1.0009
Cheyenne Light, Fuel and Power Company	**WY**	**2011**	762	30	791	579	27	53	44	1.0423	0.76037	2,905	13,408	16,313	1.0025
Citizens Gas Fuel Company	**MI**	**2007**	452	16	468	117	56	57	37	0.8725	0.25885	2,625	3,253	5,878	
Citizens Gas Fuel Company	**MI**	**2008**	453	16	469	117	57	58	36	0.8679	0.25828	2,631	1,883	4,514	0.7680
Citizens Gas Fuel Company	**MI**	**2009**	455	16	471	119	58	59	36	0.8655	0.26154	2,633	1,883	4,516	1.0004
Citizens Gas Fuel Company	**MI**	**2010**	456	16	472	119	59	60	36	0.8664	0.26096	2,640	1,883	4,523	1.0014
Citizens Gas Fuel Company	**MI**	**2011**	456	16	472	119	60	61	36	0.8676	0.26096	2,640	1,883	4,523	1.0000
Colonial Gas Company	**MA**	**2007**	1,376	7	1,382	649	31	26	135	3.2165	0.47172	11,589	5,318	16,907	
Colonial Gas Company	**MA**	**2008**	1,380	7	1,387	652	32	27	141	3.3692	0.47223	11,645	5,318	16,963	1.0033
Colonial Gas Company	**MA**	**2009**	1,383	7	1,390	653	33	28	139	3.3072	0.47204	11,695	5,318	17,013	1.0030
Colonial Gas Company	**MA**	**2010**	1,386	6	1,392	655	33	26	138	3.2836	0.47249	11,725	5,227	16,952	0.9964
Colonial Gas Company	**MA**	**2011**	1,390	6	1,397	656	34	27	134	3.1961	0.47198	11,777	5,227	17,004	1.0031
Colorado Natural Gas, Inc.	**CO**	**2007**	507	6	513	360	6	12	15	0.3576	0.71076	1,293	1,220	2,513	
Colorado Natural Gas, Inc.	**CO**	**2008**	636	6	642	456	6	13	13	0.3019	0.71606	1,810	1,220	3,030	1.2054
Colorado Natural Gas, Inc.	**CO**	**2009**	777	6	783	532	6	14	14	0.3309	0.68486	3,024	1,220	4,244	1.4009
Colorado Natural Gas, Inc.	**CO**	**2010**	829	6	835	532	7	15	15	0.3634	0.64189	3,676	1,220	4,896	1.1536
Colorado Natural Gas, Inc.	**CO**	**2011**	914	7	921	620	9	16	18	0.4347	0.67834	3,501	1,322	4,823	0.9851
Columbia Gas of Kentucky, Incorporated	**KY**	**2007**	2,530	58	2,588	851	33	18	54	1.2762	0.33636	28,722	73,791	102,514	
Columbia Gas of Kentucky, Incorporated	**KY**	**2008**	2,551	58	2,609	862	34	19	53	1.2554	0.33791	28,775	74,206	102,981	1.0046
Columbia Gas of Kentucky, Incorporated	**KY**	**2009**	2,558	58	2,616	874	34	20	52	1.2345	0.34167	28,772	74,206	102,978	1.0000
Columbia Gas of Kentucky, Incorporated	**KY**	**2010**	2,565	58	2,623	882	35	21	51	1.2245	0.34386	28,574	74,206	102,780	0.9981

Schedule 2: Natural Gas LDC Data Base

Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Columbia Gas of Kentucky, Incorporated	KY	2011	2,545	58	2,603	887	38	22	52	1.2282	0.34853	27,693	74,851	102,544	0.9977
Columbia Gas of Maryland, Incorporated	MD	2007	636	5	641	200	33	42	51	1.2122	0.31447	5,212	6,455	11,667	
Columbia Gas of Maryland, Incorporated	MD	2008	642	5	647	204	33	43	50	1.1942	0.31776	5,229	6,326	11,555	0.9904
Columbia Gas of Maryland, Incorporated	MD	2009	650	5	655	207	33	44	49	1.1778	0.31846	5,301	6,326	11,627	1.0062
Columbia Gas of Maryland, Incorporated	MD	2010	650	5	655	209	33	45	49	1.1761	0.32154	5,236	6,326	11,562	0.9944
Columbia Gas of Maryland, Incorporated	MD	2011	640	5	645	213	34	46	50	1.1953	0.33281	4,847	6,455	11,302	0.9775
Columbia Gas of Ohio, Incorporated	OH	2007	19,703	131	19,834	7,941	34	25	71	1.6924	0.40304	185,355	159,743	345,098	
Columbia Gas of Ohio, Incorporated	OH	2008	19,687	132	19,819	7,915	35	26	71	1.6858	0.40204	187,820	165,317	353,136	1.0233
Columbia Gas of Ohio, Incorporated	OH	2009	19,730	132	19,862	7,968	36	27	70	1.6777	0.40385	187,886	165,317	353,202	1.0002
Columbia Gas of Ohio, Incorporated	OH	2010	19,760	132	19,892	8,010	36	28	70	1.6719	0.40536	187,649	165,317	352,966	0.9993
Columbia Gas of Ohio, Incorporated	OH	2011	19,922	135	20,057	8,255	50	30	70	1.6580	0.41437	173,327	168,286	341,613	0.9678
Columbia Gas of Pennsylvania, Inc.	PA	2007	7,318	66	7,384	2,523	37	45	56	1.3261	0.34477	81,971	39,352	121,324	
Columbia Gas of Pennsylvania, Inc.	PA	2008	7,321	65	7,386	2,535	37	46	56	1.3297	0.34626	81,634	38,887	120,521	0.9934
Columbia Gas of Pennsylvania, Inc.	PA	2009	7,359	67	7,426	2,560	37	45	56	1.3238	0.34787	81,648	42,169	123,818	1.0273
Columbia Gas of Pennsylvania, Inc.	PA	2010	7,381	70	7,451	2,571	37	45	56	1.3248	0.34833	81,603	44,636	126,239	1.0196
Columbia Gas of Pennsylvania, Inc.	PA	2011	7,305	68	7,373	2,564	38	48	56	1.3427	0.35099	77,428	43,827	121,255	0.9605
Columbia Gas of Virginia, Incorporated	VA	2007	4,748	62	4,810	2,677	21	32	49	1.1639	0.56382	30,122	39,798	69,920	
Columbia Gas of Virginia, Incorporated	VA	2008	4,796	62	4,858	2,711	22	33	49	1.1610	0.56526	30,211	39,176	69,387	0.9924
Columbia Gas of Virginia, Incorporated	VA	2009	4,846	61	4,907	2,734	23	34	49	1.1577	0.56418	30,457	38,932	69,390	1.0000
Columbia Gas of Virginia, Incorporated	VA	2010	4,900	74	4,974	2,772	23	35	48	1.1525	0.56571	30,783	88,415	119,198	1.7178
Columbia Gas of Virginia, Incorporated	VA	2011	4,893	72	4,965	2,721	40	36	49	1.1646	0.55610	31,273	88,253	119,526	1.0028
Connecticut Natural Gas Corporation	CT	2007	2,005	0	2,005	626	36		77	1.8235	0.31222	31,140	0	31,140	
Connecticut Natural Gas Corporation	CT	2008	2,012	0	2,012	637	37		78	1.8534	0.31660	30,874	0	30,874	0.9914
Connecticut Natural Gas Corporation	CT	2009	2,011	0	2,011	640	37		78	1.8593	0.31825	30,681	0	30,681	0.9937
Connecticut Natural Gas Corporation	CT	2010	2,020	0	2,020	646	38		79	1.8717	0.31980	30,743	0	30,743	1.0020
Connecticut Natural Gas Corporation	CT	2011	2,022	0	2,022	655	38		79	1.8865	0.32394	30,658	0	30,658	0.9972
Consolidated Edison Company of New York, Inc.	NY	2007	4,262	50	4,312	785	48	54	275	6.5402	0.18419	117,432	183,328	300,760	
Consolidated Edison Company of New York, Inc.	NY	2008	4,271	50	4,321	790	48	55	247	5.8899	0.18497	118,211	183,328	301,539	1.0026
Consolidated Edison Company of New York, Inc.	NY	2009	4,281	50	4,331	796	48	56	244	5.8195	0.18594	118,925	183,328	302,253	1.0024
Consolidated Edison Company of New York, Inc.	NY	2010	4,288	50	4,338	797	49	57	245	5.8306	0.18587	120,521	183,328	303,849	1.0053
Consolidated Edison Company of New York, Inc.	NY	2011	4,308	50	4,358	806	49	58	244	5.8196	0.18709	120,857	183,328	304,185	1.0011
Consumers Energy Company	MI	2007	25,923	2,425	28,348	16,775	32	44	60	1.4354	0.64711	142,032	5,363,791	5,505,823	
Consumers Energy Company	MI	2008	25,988	2,406	28,394	16,828	32	46	60	1.4310	0.64753	142,206	5,357,924	5,500,130	0.9990
Consumers Energy Company	MI	2009	26,046	2,501	28,547	16,869	33	45	60	1.4385	0.64766	142,360	5,270,674	5,413,034	0.9842
Consumers Energy Company	MI	2010	26,096	2,451	28,547	16,905	34	47	60	1.4218	0.64780	142,784	5,485,952	5,628,736	1.0398
Consumers Energy Company	MI	2011	26,221	2,417	28,638	17,017	35	48	60	1.4203	0.64898	142,917	5,449,144	5,592,061	0.9935
Corning Natural Gas Corporation	NY	2007	325	0	325	86	46		45	1.0652	0.26462	6,292	0	6,292	
Corning Natural Gas Corporation	NY	2008	380	0	380	119	41		38	0.9144	0.31219	8,879	0	8,879	1.4113
Corning Natural Gas Corporation	NY	2009	411	0	411	121	39		35	0.8447	0.29322	9,473	0	9,473	1.0669
Corning Natural Gas Corporation	NY	2010	412	0	412	121	38		36	0.8507	0.29405	7,789	0	7,789	0.8223
Corning Natural Gas Corporation	NY	2011	412	0	412	126	38		36	0.8538	0.30640	7,869	0	7,869	1.0102
Delta Natural Gas Company, Inc.	KY	2007	1,504	424	1,928	1,082	21	20	19	0.4577	0.71941	4,788	92,356	97,144	
Delta Natural Gas Company, Inc.	KY	2008	1,511	424	1,935	1,087	21	21	19	0.4474	0.71939	4,806	92,356	97,162	1.0002
Delta Natural Gas Company, Inc.	KY	2009	1,525	424	1,949	1,095	22	22	18	0.4390	0.71803	4,852	92,356	97,208	1.0005
Delta Natural Gas Company, Inc.	KY	2010	1,813	145	1,958	1,108	23	19	18	0.4359	0.61137	9,438	44,480	53,917	0.5547
Delta Natural Gas Company, Inc.	KY	2011	1,818	145	1,964	1,112	24	20	18	0.4304	0.61131	9,455	44,478	53,933	1.0003
DTE Gas Company	MI	2007	18,520	2,310	20,830	7,648	35	39	60	1.4315	0.41296	219,276	6,111,135	6,330,411	
DTE Gas Company	MI	2008	18,603	2,298	20,901	7,690	35	40	59	1.4134	0.41337	191,202	5,200,849	5,392,050	0.8518
DTE Gas Company	MI	2009	18,590	2,304	20,894	7,890	36	41	59	1.3964	0.42442	189,637	6,260,683	6,450,320	1.1963
DTE Gas Company	MI	2010	18,638	2,226	20,864	7,919	36	43	58	1.3870	0.42488	189,826	6,244,636	6,434,462	0.9975
DTE Gas Company	MI	2011	18,704	2,225	20,929	7,962	37	44	58	1.3804	0.42568	190,038	6,236,438	6,426,476	0.9988
Duke Energy Kentucky, Inc.	KY	2007	1,336	80	1,416	525	20	36	67	1.5939	0.39302	11,994	133,988	145,982	
Duke Energy Kentucky, Inc.	KY	2008	1,337	80	1,417	532	19	37	67	1.6030	0.39764	11,961	133,988	145,949	0.9998
Duke Energy Kentucky, Inc.	KY	2009	1,343	76	1,419	539	19	38	67	1.5957	0.40171	11,968	129,220	141,188	0.9674
Duke Energy Kentucky, Inc.	KY	2010	1,339	76	1,416	541	19	39	67	1.5983	0.40376	12,323	129,017	141,339	1.0011
Duke Energy Kentucky, Inc.	KY	2011	1,341	79	1,421	541	20	40	67	1.5927	0.40371	12,328	134,379	146,707	1.0380
Duke Energy Ohio, Inc.	OH	2007	5,478	207	5,686	2,064	25	37	74	1.7741	0.37666	66,691	244,847	311,538	
Duke Energy Ohio, Inc.	OH	2008	5,479	201	5,680	2,088	25	38	75	1.7791	0.38110	66,285	237,495	303,780	0.9751
Duke Energy Ohio, Inc.	OH	2009	5,534	218	5,752	2,123	24	36	73	1.7405	0.38362	67,096	260,491	327,587	1.0784
Duke Energy Ohio, Inc.	OH	2010	5,542	218	5,760	2,155	24	37	73	1.7287	0.38887	66,446	260,179	326,625	0.9971
Duke Energy Ohio, Inc.	OH	2011	5,536	211	5,746	2,180	24	38	73	1.7301	0.39380	65,664	250,037	315,701	0.9666
East Ohio Gas Company	OH	2007	19,108	1,240	20,348	3,140	40	45	59	1.4159	0.16433	247,580	3,870,993	4,118,573	
East Ohio Gas Company	OH	2008	19,166	1,203	20,369	3,140	41	47	59	1.4044	0.16383	247,917	3,858,790	4,106,707	0.9971
East Ohio Gas Company	OH	2009	19,191	1,194	20,385	3,133	41	47	59	1.3946	0.16325	248,576	3,858,967	4,107,543	1.0002
East Ohio Gas Company	OH	2010	19,221	1,196	20,418	3,124	43	48	58	1.3839	0.16255	249,078	3,847,478	4,096,556	0.9973
East Ohio Gas Company	OH	2011	19,236	1,104	20,340	3,118	43	48	58	1.3837	0.16209	249,486	3,580,389	3,829,876	0.9349
Eastern Natural Gas Company	OH	2007	230	0	230	90	27		29	0.6885	0.39130	1,239	0	1,239	
Eastern Natural Gas Company	OH	2008	231	0	231	91	28		29	0.6816	0.39394	1,240	0	1,240	1.0008
Eastern Natural Gas Company	OH	2009	230	0	230	90	29		28	0.6784	0.39130	1,239	0	1,239	0.9992
Eastern Natural Gas Company	OH	2010	230	0	230	91	29		29	0.6796	0.39565	1,221	0	1,221	0.9857
Eastern Natural Gas Company	OH	2011	231	0	231	93	30		28	0.6712	0.40260	1,217	0	1,217	0.9964
Empire District Gas Company	MO	2007	1,108	87	1,195	671	28	52	38	0.9158	0.60593	7,343	17,689	25,031	
Empire District Gas Company	MO	2008	1,113	87	1,200	674	29	53	37	0.8872	0.60532	7,389	17,689	25,078	1.0019
Empire District Gas Company	MO	2009	1,118	87	1,205	676	30	54	37	0.8721	0.60498	7,406	17,689	25,094	1.0007

Schedule 2: Natural Gas LDC Data Base

A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
Empire District Gas Company	MO	2010	1,126	87	1,213	682	30	55	37	0.8736	0.60550	7,427	17,689	25,116	1.0009
Empire District Gas Company	MO	2011	1,130	87	1,217	684	31	56	36	0.8510	0.60562	7,440	17,689	25,128	1.0005
Energy West, Incorporated	WY	2007	326	20	346	295	74	42	18	0.4233	0.90491	541	4,066	4,608	
Energy West, Incorporated	WY	2008	332	20	352	300	74	43	18	0.4244	0.90361	553	4,066	4,619	1.0025
Energy West, Incorporated	WY	2009	347	20	367	305	71	44	17	0.4137	0.87896	621	4,066	4,688	1.0148
Energy West, Incorporated	WY	2010	351	20	371	311	69	45	17	0.4149	0.88604	614	4,066	4,681	0.9986
Energy West, Incorporated	WY	2011	373	20	393	328	66	46	17	0.3954	0.87936	663	4,066	4,730	1.0104
Fitchburg Gas and Electric Light Company	MA	2007	264	0	264	63	41		57	1.3655	0.23777	2,524	0	2,524	
Fitchburg Gas and Electric Light Company	MA	2008	264	0	264	63	42		58	1.3709	0.23983	2,545	0	2,545	1.0081
Fitchburg Gas and Electric Light Company	MA	2009	263	0	263	64	42		58	1.3818	0.24256	2,522	0	2,522	0.9910
Fitchburg Gas and Electric Light Company	MA	2010	263	0	263	64	43		58	1.3823	0.24271	2,528	0	2,528	1.0026
Fitchburg Gas and Electric Light Company	MA	2011	263	0	263	64	43		59	1.3935	0.24351	2,539	0	2,539	1.0042
Florida Public Utilities Company	FL	2007	1,611	0	1,611	1,031	24		32	0.7692	0.63998	9,176	0	9,176	
Florida Public Utilities Company	FL	2008	1,639	0	1,639	1,049	25		32	0.7562	0.64002	9,270	0	9,270	1.0102
Florida Public Utilities Company	FL	2009	1,632	0	1,632	1,047	25		32	0.7545	0.64154	9,236	0	9,236	0.9964
Florida Public Utilities Company	FL	2010	1,664	0	1,664	1,069	26		31	0.7468	0.64232	9,358	0	9,358	1.0132
Florida Public Utilities Company	FL	2011	1,697	0	1,697	1,084	27		31	0.7430	0.63875	9,675	0	9,675	1.0339
Hope Gas, Inc.	WV	2007	2,936	8	2,944	1,161	36	20	39	0.9270	0.39544	30,572	1,455	32,027	
Hope Gas, Inc.	WV	2008	3,028	8	3,036	1,245	46	17	38	0.8953	0.41119	29,765	1,567	31,332	0.9783
Hope Gas, Inc.	WV	2009	3,063	8	3,071	1,250	44	18	37	0.8818	0.40817	30,285	1,567	31,851	1.0166
Hope Gas, Inc.	WV	2010	3,074	8	3,082	1,251	44	18	37	0.8767	0.40694	30,663	1,525	32,188	1.0106
Hope Gas, Inc.	WV	2011	3,114	0	3,114	1,260	43		36	0.8678	0.40457	31,565	0	31,565	0.9806
Illinois Gas Company	IL	2007	354	0	354	217	28		28	0.6600	0.61317	1,416	0	1,416	
Illinois Gas Company	IL	2008	351	0	351	217	29		28	0.6606	0.61651	1,404	0	1,404	0.9911
Illinois Gas Company	IL	2009	353	0	353	219	29		28	0.6557	0.61943	1,404	0	1,404	1.0000
Illinois Gas Company	IL	2010	354	0	354	220	30		27	0.6541	0.62067	1,405	0	1,405	1.0006
Illinois Gas Company	IL	2011	359	0	359	221	31		27	0.6436	0.61676	1,426	0	1,426	1.0154
Indiana Gas Company, Inc.	IN	2007	12,333	570	12,903	7,080	26	33	43	1.0327	0.57407	95,801	504,431	600,232	
Indiana Gas Company, Inc.	IN	2008	12,326	633	12,959	7,130	27	35	43	1.0309	0.57845	91,500	537,906	629,406	1.0486
Indiana Gas Company, Inc.	IN	2009	12,387	622	13,009	7,193	27	38	43	1.0233	0.58069	91,645	523,014	614,659	0.9766
Indiana Gas Company, Inc.	IN	2010	12,413	621	13,034	7,227	28	38	43	1.0258	0.58221	91,611	524,113	615,724	1.0017
Indiana Gas Company, Inc.	IN	2011	12,457	673	13,130	7,284	28	41	43	1.0219	0.58473	91,622	536,567	628,189	1.0202
Intermountain Gas Company	ID	2007	5,572	322	5,894	4,185	21	33	48	1.1511	0.75108	17,082	162,273	179,355	
Intermountain Gas Company	ID	2008	5,763	320	6,083	4,325	23	34	49	1.1727	0.75048	17,583	161,867	179,449	1.0005
Intermountain Gas Company	ID	2009	5,882	321	6,203	4,405	24	35	49	1.1721	0.74889	18,170	162,070	180,240	1.0044
Intermountain Gas Company	ID	2010	5,944	322	6,266	4,441	25	35	49	1.1748	0.74714	19,348	161,186	180,534	1.0016
Intermountain Gas Company	ID	2011	5,964	306	6,270	4,455	26	36	50	1.1871	0.74698	19,412	140,917	160,329	0.8881
Kansas Gas Service Company	KS	2007	11,110	1,587	12,697	6,799	33	30	50	1.1980	0.61197	69,013	1,341,926	1,410,939	
Kansas Gas Service Company	KS	2008	11,086	1,587	12,673	6,797	33	30	50	1.1870	0.61312	68,651	1,342,440	1,411,091	1.0001
Kansas Gas Service Company	KS	2009	11,138	1,583	12,721	6,834	34	41	50	1.1861	0.61358	68,705	1,341,224	1,409,930	0.9992
Kansas Gas Service Company	KS	2010	11,271	1,579	12,850	6,915	34	33	49	1.1715	0.61352	69,981	1,344,620	1,414,601	1.0033
Kansas Gas Service Company	KS	2011	11,283	1,568	12,851	6,936	35	33	49	1.1717	0.61472	69,591	1,339,659	1,409,251	0.9962
KeySpan Gas East Corporation	NY	2007	4,033	196	4,229	397	48	39	127	3.0140	0.09844	121,571	634,114	755,685	
KeySpan Gas East Corporation	NY	2008	4,040	199	4,239	397	48	40	127	3.0299	0.09827	119,592	647,661	767,253	1.0153
KeySpan Gas East Corporation	NY	2009	4,069	204	4,273	399	48	40	128	3.0480	0.09806	120,683	655,323	776,006	1.0114
KeySpan Gas East Corporation	NY	2010	4,095	204	4,299	412	48	41	128	3.0482	0.10061	121,459	654,693	776,152	1.0002
KeySpan Gas East Corporation	NY	2011	4,109	204	4,313	414	49	42	128	3.0571	0.10075	121,910	658,286	780,196	1.0052
Laclede Gas Company	MO	2007	8,322	222	8,544	5,108	35	38	75	1.7953	0.61379	73,423	422,593	496,017	
Laclede Gas Company	MO	2008	8,408	222	8,630	5,175	35	39	75	1.7755	0.61549	73,606	422,593	496,199	1.0004
Laclede Gas Company	MO	2009	8,418	222	8,640	5,188	36	40	74	1.7712	0.61630	73,390	422,593	495,983	0.9996
Laclede Gas Company	MO	2010	8,462	222	8,684	5,214	37	41	74	1.7582	0.61617	73,617	422,508	496,125	1.0003
Laclede Gas Company	MO	2011	8,469	222	8,691	5,228	38	42	73	1.7501	0.61731	73,352	422,508	495,859	0.9995
Louisville Gas and Electric Company	KY	2007	4,201	374	4,575	1,930	28	33	71	1.6946	0.45941	42,064	419,910	461,974	
Louisville Gas and Electric Company	KY	2008	4,230	373	4,603	1,950	31	34	68	1.6237	0.46099	42,008	419,706	461,714	0.9994
Louisville Gas and Electric Company	KY	2009	4,249	375	4,624	1,971	31	35	68	1.6274	0.46387	41,937	423,547	465,485	1.0082
Louisville Gas and Electric Company	KY	2010	4,235	374	4,609	1,982	32	36	70	1.6564	0.46803	41,393	422,196	463,589	0.9959
Louisville Gas and Electric Company	KY	2011	4,290	374	4,665	2,032	32	37	68	1.6268	0.47355	41,439	422,617	464,056	1.0010
Madison Gas and Electric Company	WI	2007	2,398	0	2,398	1,344	28		58	1.3817	0.56047	15,508	0	15,508	
Madison Gas and Electric Company	WI	2008	2,427	0	2,427	1,363	28		58	1.3883	0.56160	15,615	0	15,615	1.0069
Madison Gas and Electric Company	WI	2009	2,449	0	2,449	1,370	26		58	1.3845	0.55941	16,088	0	16,088	1.0303
Madison Gas and Electric Company	WI	2010	2,462	0	2,462	1,376	27		58	1.3846	0.55890	16,201	0	16,201	1.0070
Madison Gas and Electric Company	WI	2011	2,478	0	2,478	1,379	27		58	1.3843	0.55650	16,361	0	16,361	1.0099
Michigan Gas Utilities Corporation	MI	2007	3,591	155	3,747	1,937	29	39	44	1.0466	0.53940	18,493	66,366	84,859	
Michigan Gas Utilities Corporation	MI	2008	3,632	146	3,778	1,950	30	40	43	1.0359	0.53701	19,268	63,001	82,269	0.9695
Michigan Gas Utilities Corporation	MI	2009	3,660	146	3,806	1,974	30	41	43	1.0278	0.53936	19,314	63,002	82,316	1.0006
Michigan Gas Utilities Corporation	MI	2010	3,685	146	3,831	1,985	31	42	43	1.0245	0.53862	19,419	62,855	82,274	0.9995
Michigan Gas Utilities Corporation	MI	2011	3,707	148	3,855	1,988	32	43	43	1.0225	0.53621	19,553	62,966	82,518	1.0030
Midwest Energy, Inc.	KS	2007	2,985	59	3,044	2,327	36	52	14	0.3247	0.77951	7,578	11,996	19,574	
Midwest Energy, Inc.	KS	2008	3,005	59	3,064	2,347	37	51	14	0.3241	0.78098	7,598	11,996	19,594	1.0010
Midwest Energy, Inc.	KS	2009	2,994	59	3,053	2,336	37	54	14	0.3252	0.78018	7,587	11,996	19,582	0.9994
Midwest Energy, Inc.	KS	2010	2,963	59	3,022	2,301	38	52	14	0.3280	0.77648	7,630	11,996	19,626	1.0022
Midwest Energy, Inc.	KS	2011	2,886	59	2,945	2,231	38	53	14	0.3369	0.77295	7,517	11,996	19,512	0.9942
Midwest Natural Gas Corporation	IN	2007	592	0	592	359	25		25	0.5845	0.60642	3,100	0	3,100	
Midwest Natural Gas Corporation	IN	2008	594	0	594	360	26		24	0.5722	0.60606	3,107	0	3,107	1.0024

Schedule 2: Natural Gas LDC Data Base

A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
Midwest Natural Gas Corporation	IN	2009	594	0	594	360	27		24	0.5650	0.60606	3,107	0	3,107	1.0000
Midwest Natural Gas Corporation	IN	2010	584	0	584	361	28		24	0.5716	0.61815	3,063	0	3,063	0.9858
Midwest Natural Gas Corporation	IN	2011	586	0	586	364	28		24	0.5658	0.62116	3,048	0	3,048	0.9949
Midwest Natural Gas, Inc.	WI	2007	605	0	605	401	13		23	0.5499	0.66358	2,102	0	2,102	
Midwest Natural Gas, Inc.	WI	2008	614	0	614	408	14		23	0.5514	0.66472	2,122	0	2,122	1.0097
Midwest Natural Gas, Inc.	WI	2009	616	0	616	409	15		23	0.5557	0.66315	2,139	0	2,139	1.0080
Midwest Natural Gas, Inc.	WI	2010	629	0	629	416	16		23	0.5524	0.66063	2,185	0	2,185	1.0215
Midwest Natural Gas, Inc.	WI	2011	641	0	641	425	16		23	0.5496	0.66375	2,207	0	2,207	1.0099
Missouri Gas Energy	MO	2007	8,463	45	8,509	4,046	32	43	59	1.4042	0.47810	91,119	78,121	169,241	
Missouri Gas Energy	MO	2008	8,512	45	8,558	4,072	33	44	58	1.3918	0.47841	91,171	78,162	169,333	1.0005
Missouri Gas Energy	MO	2009	8,536	45	8,582	4,083	34	45	58	1.3830	0.47835	91,173	78,148	169,322	0.9999
Missouri Gas Energy	MO	2010	8,543	45	8,589	4,087	35	48	58	1.3747	0.47836	90,974	77,989	168,962	0.9979
Missouri Gas Energy	MO	2011	8,545	45	8,590	4,092	35	49	57	1.3634	0.47889	90,637	77,989	168,626	0.9980
Mobile Gas Service Corporation	AL	2007	2,211	53	2,264	1,548	27	22	41	0.9878	0.70014	16,756	47,758	64,513	
Mobile Gas Service Corporation	AL	2008	2,238	53	2,291	1,562	28	23	41	0.9711	0.69794	16,808	47,758	64,565	1.0008
Mobile Gas Service Corporation	AL	2009	2,236	53	2,289	1,560	28	24	40	0.9528	0.69767	16,806	47,758	64,563	1.0000
Mobile Gas Service Corporation	AL	2010	2,240	53	2,293	1,564	29	25	40	0.9462	0.69821	16,755	47,205	63,961	0.9907
Mobile Gas Service Corporation	AL	2011	2,251	46	2,297	1,567	29	23	38	0.9142	0.69594	17,758	38,646	56,404	0.8819
Mountaineer Gas Company	WV	2007	4,977	21	4,998	1,984	42	41	44	1.0434	0.39863	36,795	5,357	42,152	
Mountaineer Gas Company	WV	2008	5,166	14	5,180	2,072	43	53	42	1.0100	0.40108	38,276	2,846	41,123	0.9756
Mountaineer Gas Company	WV	2009	5,270	14	5,284	2,157	44	54	41	0.9771	0.40930	38,568	2,846	41,415	1.0071
Mountaineer Gas Company	WV	2010	5,625	14	5,639	2,427	44	53	39	0.9185	0.43147	39,638	2,765	42,403	1.0239
Mountaineer Gas Company	WV	2011	5,655	0	5,655	2,452	45		39	0.9289	0.43360	39,739	0	39,739	0.9372
Mt. Carmel Public Utility Company	IL	2007	104	0	104	48	37		35	0.8268	0.46154	688	0	688	
Mt. Carmel Public Utility Company	IL	2008	104	0	104	48	38		35	0.8248	0.46154	688	0	688	1.0000
Mt. Carmel Public Utility Company	IL	2009	104	0	104	48	36		34	0.8176	0.46206	688	0	688	1.0001
Mt. Carmel Public Utility Company	IL	2010	104	0	104	48	36		34	0.8083	0.46247	689	0	689	1.0016
Mt. Carmel Public Utility Company	IL	2011	105	0	105	48	37		34	0.8051	0.46322	689	0	689	0.9993
National Fuel Gas Distribution Corporation	PA	2007	4,915	63	4,978	1,851	33	44	43	1.0129	0.37660	35,766	48,703	84,469	
National Fuel Gas Distribution Corporation	PA	2008	4,914	63	4,977	1,878	34	45	43	1.0152	0.38217	35,368	48,703	84,071	0.9953
National Fuel Gas Distribution Corporation	PA	2009	4,909	65	4,974	1,907	35	45	43	1.0136	0.38847	34,550	49,110	83,660	0.9951
National Fuel Gas Distribution Corporation	PA	2010	4,898	66	4,963	1,921	36	46	43	1.0186	0.39232	34,237	49,763	84,000	1.0041
National Fuel Gas Distribution Corporation	PA	2011	4,894	66	4,960	1,936	36	47	43	1.0187	0.39553	34,057	49,775	83,832	0.9980
New Jersey Natural Gas Company	NJ	2007	6,619	214	6,833	4,160	27	28	70	1.6754	0.62849	44,231	383,098	427,329	
New Jersey Natural Gas Company	NJ	2008	6,662	214	6,876	4,180	27	26	71	1.6835	0.62744	44,854	395,063	439,917	1.0295
New Jersey Natural Gas Company	NJ	2009	6,716	214	6,930	4,211	28	27	71	1.6803	0.62701	45,471	395,063	440,534	1.0014
New Jersey Natural Gas Company	NJ	2010	6,786	214	7,000	4,254	28	28	70	1.6788	0.62688	47,065	394,403	441,468	1.0021
New Jersey Natural Gas Company	NJ	2011	6,847	228	7,075	4,296	29	29	70	1.6755	0.62743	47,875	430,118	477,993	1.0827
New York State Electric & Gas Corporation	NY	2007	4,653	72	4,725	1,490	35	12	54	1.2947	0.32022	63,932	75,550	139,482	
New York State Electric & Gas Corporation	NY	2008	4,675	72	4,747	1,502	36	13	55	1.2984	0.32128	64,243	75,550	139,793	1.0022
New York State Electric & Gas Corporation	NY	2009	4,698	72	4,770	1,525	36	14	55	1.2989	0.32461	64,241	75,550	139,791	1.0000
New York State Electric & Gas Corporation	NY	2010	4,710	72	4,782	1,537	37	15	55	1.3007	0.32642	64,274	75,175	139,449	0.9976
New York State Electric & Gas Corporation	NY	2011	4,723	71	4,794	1,555	37	16	54	1.2960	0.32918	65,117	75,041	140,158	1.0051
Niagara Mohawk Power Corporation	NY	2007	8,508	278	8,786	2,006	34	36	65	1.5474	0.23578	157,907	601,354	759,261	
Niagara Mohawk Power Corporation	NY	2008	8,489	278	8,767	2,043	34	37	66	1.5630	0.24066	153,509	601,354	754,863	0.9942
Niagara Mohawk Power Corporation	NY	2009	8,507	278	8,785	2,088	34	38	66	1.5714	0.24540	153,379	601,354	754,733	0.9998
Niagara Mohawk Power Corporation	NY	2010	8,523	277	8,799	2,121	35	41	66	1.5776	0.24887	153,064	602,696	755,760	1.0014
Niagara Mohawk Power Corporation	NY	2011	8,528	277	8,805	2,144	36	42	67	1.5842	0.25136	152,669	602,696	755,365	0.9995
North Shore Gas Company	IL	2007	2,276	96	2,372	1,402	30	25	67	1.5851	0.61599	15,155	278,008	293,164	
North Shore Gas Company	IL	2008	2,284	95	2,378	1,408	31	27	67	1.5847	0.61667	15,230	270,500	285,730	0.9746
North Shore Gas Company	IL	2009	2,297	85	2,382	1,414	31	29	66	1.5798	0.61554	15,247	269,153	284,400	0.9953
North Shore Gas Company	IL	2010	2,371	86	2,457	1,404	32	30	64	1.5301	0.59234	30,979	269,193	300,172	1.0555
North Shore Gas Company	IL	2011	2,303	86	2,389	1,405	33	31	66	1.5771	0.61011	18,560	269,193	287,752	0.9586
Northeast Ohio Natural Gas Corp.	OH	2007	604	10	613	369	11	3	15	0.3606	0.61178	2,137	31,851	33,989	
Northeast Ohio Natural Gas Corp.	OH	2008	709	10	719	429	16	4	20	0.4874	0.60479	2,546	31,851	34,397	1.0120
Northeast Ohio Natural Gas Corp.	OH	2009	725	10	734	437	16	5	20	0.4791	0.60279	2,602	31,851	34,453	1.0016
Northeast Ohio Natural Gas Corp.	OH	2010	746	10	755	446	17	6	21	0.4969	0.59781	2,774	31,851	34,625	1.0050
Northeast Ohio Natural Gas Corp.	OH	2011	758	10	768	451	17	7	20	0.4755	0.59504	2,858	31,851	34,710	1.0024
Northern Illinois Gas Company	IL	2007	32,808	1,194	34,002	22,217	29	40	64	1.5147	0.67718	213,751	4,478,406	4,692,157	
Northern Illinois Gas Company	IL	2008	32,973	1,175	34,148	22,293	30	41	64	1.5157	0.67610	212,456	4,451,604	4,664,060	0.9940
Northern Illinois Gas Company	IL	2009	32,848	1,175	34,023	22,245	31	42	64	1.5208	0.67721	210,208	4,451,604	4,661,812	0.9995
Northern Illinois Gas Company	IL	2010	32,864	1,173	34,037	22,290	32	42	64	1.5232	0.67825	208,700	4,444,461	4,653,161	0.9981
Northern Illinois Gas Company	IL	2011	32,853	1,172	34,025	22,295	32	44	64	1.5292	0.67863	207,100	4,452,536	4,659,636	1.0014
NSTAR Gas Company	MA	2007	3,086	1	3,087	1,053	37	32	84	2.0009	0.34122	40,614	1,291	41,905	
NSTAR Gas Company	MA	2008	3,126	1	3,127	1,065	37	33	83	1.9832	0.34069	41,164	1,291	42,455	1.0131
NSTAR Gas Company	MA	2009	3,130	1	3,131	1,067	37	34	85	2.0287	0.34089	41,241	1,291	42,532	1.0018
NSTAR Gas Company	MA	2010	3,141	1	3,142	1,072	38	35	85	2.0336	0.34129	41,247	1,291	42,538	1.0001
NSTAR Gas Company	MA	2011	3,154	1	3,155	1,081	38	36	86	2.0399	0.34274	41,410	1,291	42,701	1.0038
Ohio Gas Company	OH	2007	1,141	0	1,141	429	34		41	0.9685	0.37606	8,487	0	8,487	
Ohio Gas Company	OH	2008	1,145	0	1,145	430	35		41	0.9663	0.37536	8,522	0	8,522	1.0042
Ohio Gas Company	OH	2009	1,147	0	1,147	430	36		40	0.9637	0.37515	8,536	0	8,536	1.0016
Ohio Gas Company	OH	2010	1,152	0	1,152	431	36		40	0.9616	0.37412	8,662	0	8,662	1.0148
Ohio Gas Company	OH	2011	1,189	0	1,189	442	37		40	0.9420	0.37155	9,261	0	9,261	1.0691
Oklahoma Natural Gas Company	OK	2007	16,161	1,292	17,453	10,394	22	36	48	1.1515	0.64315	85,863	617,774	703,638	

Schedule 2: Natural Gas LDC Data Base

A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
Oklahoma Natural Gas Company	OK	2008	16,480	1,027	17,507	10,694	23	36	48	1.1527	0.64891	86,116	521,090	607,206	0.8630
Oklahoma Natural Gas Company	OK	2009	16,520	1,066	17,586	10,735	24	37	48	1.1492	0.64982	86,076	633,693	719,769	1.1854
Oklahoma Natural Gas Company	OK	2010	16,957	902	17,859	10,854	30	39	47	1.1206	0.64009	89,502	553,187	642,688	0.8929
Oklahoma Natural Gas Company	OK	2011	17,163	805	17,968	11,056	31	40	47	1.1256	0.64418	106,874	538,990	645,864	1.0049
Pacific Gas and Electric Company	CA	2007	41,804	5,711	47,515	28,896	34	41	91	2.1576	0.69124	240,603	19,841,135	20,081,738	
Pacific Gas and Electric Company	CA	2008	42,017	5,721	47,738	29,048	34	42	91	2.1732	0.69135	241,416	19,997,715	20,239,131	1.0078
Pacific Gas and Electric Company	CA	2009	42,142	5,722	47,864	29,138	35	43	90	2.1441	0.69142	241,781	20,090,532	20,332,313	1.0046
Pacific Gas and Electric Company	CA	2010	42,213	5,727	47,940	29,198	36	43	90	2.1389	0.69169	242,461	20,225,012	20,467,473	1.0066
Pacific Gas and Electric Company	CA	2011	42,309	5,744	48,053	29,256	37	44	90	2.1543	0.69148	242,915	20,289,404	20,532,319	1.0032
PECO Energy Company	PA	2007	6,658	31	6,689	2,491	31	37	72	1.7139	0.37414	90,251	11,741	101,992	
PECO Energy Company	PA	2008	6,691	31	6,722	2,497	32	38	72	1.7127	0.37319	91,034	11,741	102,775	1.0077
PECO Energy Company	PA	2009	6,703	31	6,734	2,503	33	39	72	1.7189	0.37341	91,128	11,741	102,869	1.0009
PECO Energy Company	PA	2010	6,718	31	6,749	2,512	34	40	72	1.7214	0.37392	91,200	11,741	102,941	1.0007
PECO Energy Company	PA	2011	6,724	31	6,755	2,516	34	41	73	1.7402	0.37422	91,308	11,741	103,049	1.0011
Peoples Gas Light and Coke Company	IL	2007	4,029	441	4,470	744	40	34	186	4.4228	0.18466	149,425	2,660,468	2,809,893	
Peoples Gas Light and Coke Company	IL	2008	4,063	393	4,456	797	40	35	186	4.4345	0.19618	148,661	2,650,709	2,799,369	0.9963
Peoples Gas Light and Coke Company	IL	2009	4,086	393	4,479	821	40	36	184	4.3711	0.20103	148,629	2,650,709	2,799,338	1.0000
Peoples Gas Light and Coke Company	IL	2010	4,159	419	4,578	837	41	37	179	4.2608	0.20121	161,838	2,779,436	2,941,274	1.0507
Peoples Gas Light and Coke Company	IL	2011	4,119	419	4,538	881	41	38	182	4.3429	0.21390	148,875	2,778,969	2,927,844	0.9954
Peoples Gas System	FL	2007	10,577	113	10,690	6,563	21	13	31	0.7454	0.62043	58,759	155,539	214,298	
Peoples Gas System	FL	2008	10,774	143	10,917	6,674	22	11	31	0.7310	0.61948	59,940	196,784	256,725	1.1980
Peoples Gas System	FL	2009	10,918	143	11,061	6,713	22	12	30	0.7194	0.61480	61,525	196,784	258,310	1.0062
Peoples Gas System	FL	2010	11,164	168	11,332	6,841	24	18	30	0.7060	0.61275	63,601	226,544	290,145	1.1232
Peoples Gas System	FL	2011	11,411	168	11,579	6,888	24	19	29	0.6968	0.60364	65,897	226,544	292,442	1.0079
Philadelphia Gas Works Co.	PA	2007	3,023	2	3,025	74	52	32	165	3.9224	0.02448	105,893	7,613	113,505	
Philadelphia Gas Works Co.	PA	2008	3,024	2	3,026	75	53	33	165	3.9211	0.02480	105,696	7,613	113,309	0.9983
Philadelphia Gas Works Co.	PA	2009	3,029	2	3,031	74	54	34	164	3.8968	0.02443	105,783	7,613	113,395	1.0008
Philadelphia Gas Works Co.	PA	2010	3,029	2	3,031	74	54	35	164	3.9066	0.02443	105,506	7,993	113,499	1.0009
Philadelphia Gas Works Co.	PA	2011	3,029	2	3,031	74	55	36	165	3.9195	0.02443	105,414	7,993	113,408	0.9992
Pike County Light and Power Company	PA	2007	20	0	20	3	83		59	1.3955	0.15000	173	0	173	
Pike County Light and Power Company	PA	2008	20	0	20	3	84		60	1.4193	0.15000	173	0	173	1.0000
Pike County Light and Power Company	PA	2009	19	0	19	5	46		63	1.4940	0.26316	143	0	143	0.8297
Pike County Light and Power Company	PA	2010	19	0	19	4	46		65	1.5363	0.22348	145	0	145	1.0135
Pike County Light and Power Company	PA	2011	19	0	19	4	47		64	1.5327	0.23164	144	0	144	0.9927
Pike Natural Gas Co	OH	2007	281	0	281	136	31		25	0.6055	0.48257	1,856	0	1,856	
Pike Natural Gas Co	OH	2008	282	0	282	136	32		25	0.6002	0.48261	1,859	0	1,859	1.0012
Pike Natural Gas Co	OH	2009	283	0	283	137	33		25	0.5994	0.48499	1,860	0	1,860	1.0007
Pike Natural Gas Co	OH	2010	284	0	284	138	34		25	0.5989	0.48644	1,861	0	1,861	1.0004
Pike Natural Gas Co	OH	2011	285	0	285	139	34		25	0.5940	0.48737	1,863	0	1,863	1.0015
Pivotal Utility Holdings, Inc.	MD	2007	88	0	88	45	22		68	1.6231	0.51136	392	0	392	
Pivotal Utility Holdings, Inc.	MD	2008	95	0	95	57	20		63	1.5083	0.60000	360	0	360	0.9181
Pivotal Utility Holdings, Inc.	MD	2009	96	0	96	58	21		64	1.5127	0.60417	361	0	361	1.0028
Pivotal Utility Holdings, Inc.	MD	2010	96	0	96	57	23		63	1.4990	0.59505	377	0	377	1.0451
Pivotal Utility Holdings, Inc.	MD	2011	97	0	97	58	24		63	1.5078	0.59353	388	0	388	1.0293
Pivotal Utility Holdings, Inc.	NJ	2007	3,037	22	3,059	1,072	42	32	89	2.1148	0.35298	40,558	14,265	54,823	
Pivotal Utility Holdings, Inc.	NJ	2008	3,042	22	3,064	1,112	38	33	89	2.1217	0.36555	39,985	14,265	54,250	0.9895
Pivotal Utility Holdings, Inc.	NJ	2009	3,072	22	3,094	1,122	38	34	88	2.1033	0.36523	41,039	14,265	55,304	1.0194
Pivotal Utility Holdings, Inc.	NJ	2010	3,107	21	3,128	1,143	37	34	88	2.0879	0.36788	41,490	14,123	55,613	1.0056
Pivotal Utility Holdings, Inc.	NJ	2011	3,130	21	3,152	1,167	37	35	87	2.0826	0.37277	42,223	14,123	56,346	1.0132
Public Service Company of Colorado	CO	2007	20,914	2,336	23,250	16,114	24	56	54	1.2956	0.77049	110,392	1,184,765	1,295,157	
Public Service Company of Colorado	CO	2008	21,153	2,330	23,483	16,313	25	39	54	1.2974	0.77119	110,882	1,527,115	1,637,997	1.2647
Public Service Company of Colorado	CO	2009	21,260	2,251	23,511	9,525	26	39	55	1.3102	0.44801	190,595	1,443,194	1,633,788	0.9974
Public Service Company of Colorado	CO	2010	21,318	2,310	23,629	9,565	27	40	55	1.3124	0.44866	191,677	1,201,604	1,393,281	0.8528
Public Service Company of Colorado	CO	2011	22,844	2,351	25,195	17,457	67	40	52	1.2387	0.76420	110,907	1,261,412	1,372,319	0.9850
Public Service Company of North Carolina, Incorporated	NC	2007	9,672	594	10,266	5,722	20	46	43	1.0308	0.59161	58,807	371,685	430,492	
Public Service Company of North Carolina, Incorporated	NC	2008	9,908	596	10,504	5,863	20	37	44	1.0393	0.59179	59,859	377,193	437,052	1.0152
Public Service Company of North Carolina, Incorporated	NC	2009	10,008	597	10,605	5,920	21	38	44	1.0460	0.59149	60,338	377,439	437,777	1.0017
Public Service Company of North Carolina, Incorporated	NC	2010	10,128	596	10,724	5,992	22	39	44	1.0495	0.59162	60,971	376,318	437,289	0.9989
Public Service Company of North Carolina, Incorporated	NC	2011	10,270	616	10,886	6,069	22	40	44	1.0506	0.59094	61,795	403,931	465,726	1.0650
Public Service Electric and Gas Company	NJ	2007	17,615	61	17,676	6,274	36	26	98	2.3337	0.35617	317,442	180,707	498,149	
Public Service Electric and Gas Company	NJ	2008	17,609	61	17,670	6,325	37	27	99	2.3477	0.35919	314,538	180,707	495,245	0.9942
Public Service Electric and Gas Company	NJ	2009	17,585	61	17,646	6,351	37	28	101	2.3941	0.36116	312,825	180,707	493,532	0.9965
Public Service Electric and Gas Company	NJ	2010	17,616	62	17,678	6,391	37	29	101	2.3957	0.36280	313,107	178,245	491,352	0.9956
Public Service Electric and Gas Company	NJ	2011	17,646	62	17,708	6,425	38	30	100	2.3929	0.36411	312,787	178,245	491,032	0.9993
Puget Sound Energy, Inc.	WA	2007	11,740	30	11,770	9,028	21	35	61	1.4608	0.76899	53,903	32,319	86,223	
Puget Sound Energy, Inc.	WA	2008	11,896	34	11,930	9,137	21	33	62	1.4728	0.76807	55,547	35,748	91,295	1.0588
Puget Sound Energy, Inc.	WA	2009	11,979	28	12,007	9,189	22	31	62	1.4806	0.76709	57,659	26,740	84,400	0.9245
Puget Sound Energy, Inc.	WA	2010	12,008	27	12,035	9,216	23	32	62	1.4856	0.76749	57,885	26,818	84,703	1.0036
Puget Sound Energy, Inc.	WA	2011	12,041	27	12,068	9,240	23	33	63	1.4932	0.76738	58,156	26,697	84,853	1.0018
Rochester Gas and Electric Corporation	NY	2007	4,666	106	4,772	2,570	32	42	62	1.4795	0.55079	45,637	255,071	300,708	
Rochester Gas and Electric Corporation	NY	2008	4,686	106	4,792	2,595	32	43	62	1.4798	0.55378	45,314	255,071	300,385	0.9989
Rochester Gas and Electric Corporation	NY	2009	4,709	106	4,815	2,611	33	44	62	1.4794	0.55447	45,387	255,071	300,458	1.0002
Rochester Gas and Electric Corporation	NY	2010	4,730	106	4,836	2,633	33	44	62	1.4838	0.55668	45,360	255,071	300,431	0.9999
Rochester Gas and Electric Corporation	NY	2011	4,740	106	4,846	2,645	33	45	63	1.4890	0.55806	45,285	255,071	300,355	0.9997

Schedule 2: Natural Gas LDC Data Base

A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
San Diego Gas & Electric Co.	CA	2007	8,338	243	8,581	6,148	29	42	97	2.3174	0.73735	40,590	919,337	959,927	
San Diego Gas & Electric Co.	CA	2008	8,317	242	8,559	6,192	30	42	98	2.3340	0.74450	29,695	919,133	948,828	0.9884
San Diego Gas & Electric Co.	CA	2009	8,345	246	8,591	6,216	31	44	98	2.3352	0.74488	29,593	919,947	949,540	1.0008
San Diego Gas & Electric Co.	CA	2010	8,386	251	8,637	6,245	31	43	98	2.3362	0.74469	29,923	922,051	951,974	1.0026
San Diego Gas & Electric Co.	CA	2011	8,417	245	8,662	6,269	32	44	98	2.3427	0.74480	30,513	922,299	952,812	1.0009
South Carolina Electric & Gas Co.	SC	2007	8,061	446	8,507	5,630	32	34	35	0.8374	0.69842	40,705	105,170	145,875	
South Carolina Electric & Gas Co.	SC	2008	8,281	475	8,756	5,786	32	34	35	0.8270	0.69871	40,403	111,066	151,469	1.0383
South Carolina Electric & Gas Co.	SC	2009	8,447	453	8,900	5,838	33	34	35	0.8231	0.69113	41,363	110,704	152,067	1.0039
South Carolina Electric & Gas Co.	SC	2010	8,488	453	8,941	5,889	33	35	35	0.8282	0.69381	42,113	109,445	151,558	0.9967
South Carolina Electric & Gas Co.	SC	2011	8,578	445	9,023	5,932	34	35	35	0.8296	0.69151	42,872	109,360	152,233	1.0045
South Jersey Gas Company	NJ	2007	5,721	107	5,828	3,499	61	23	63	1.4887	0.61161	50,964	214,264	265,228	
South Jersey Gas Company	NJ	2008	5,766	107	5,873	3,537	35	24	57	1.3670	0.61342	51,630	214,264	265,894	1.0025
South Jersey Gas Company	NJ	2009	5,867	107	5,974	3,590	35	25	57	1.3604	0.61190	54,295	214,264	268,558	1.0100
South Jersey Gas Company	NJ	2010	5,939	122	6,061	3,648	34	26	57	1.3560	0.61424	57,057	269,812	326,870	1.2171
South Jersey Gas Company	NJ	2011	6,020	124	6,144	3,703	33	27	57	1.3522	0.61512	59,529	270,260	329,789	1.0089
Southern California Gas Company	CA	2007	47,566	3,961	51,527	31,331	30	45	106	2.5169	0.65868	263,148	17,900,483	18,163,631	
Southern California Gas Company	CA	2008	47,540	3,999	51,539	31,374	34	45	106	2.5262	0.65995	250,798	17,337,723	17,588,522	0.9683
Southern California Gas Company	CA	2009	47,651	3,989	51,640	31,472	35	46	106	2.5340	0.66047	250,895	17,326,658	17,577,553	0.9994
Southern California Gas Company	CA	2010	48,868	3,730	52,598	32,153	36	46	105	2.4978	0.65796	296,057	17,134,299	17,430,356	0.9916
Southern California Gas Company	CA	2011	49,008	3,613	52,621	32,226	37	47	105	2.5114	0.65757	282,519	17,013,798	17,296,317	0.9923
Southern Connecticut Gas Company	CT	2007	2,261	0	2,261	517	40		77	1.8388	0.22866	48,231	0	48,231	
Southern Connecticut Gas Company	CT	2008	2,266	0	2,266	525	41		77	1.8395	0.23169	48,171	0	48,171	0.9987
Southern Connecticut Gas Company	CT	2009	2,269	0	2,269	529	42		77	1.8442	0.23314	48,072	0	48,072	0.9980
Southern Connecticut Gas Company	CT	2010	2,273	0	2,273	540	42		77	1.8389	0.23757	47,952	0	47,952	0.9975
Southern Connecticut Gas Company	CT	2011	2,281	0	2,281	550	43		78	1.8507	0.24112	47,937	0	47,937	0.9997
Southern Indiana Gas and Electric Company, Inc.	IN	2007	3,076	139	3,215	1,967	26	37	35	0.8234	0.63947	18,644	139,900	158,544	
Southern Indiana Gas and Electric Company, Inc.	IN	2008	3,065	139	3,204	1,979	26	38	35	0.8222	0.64568	18,272	139,900	158,172	0.9977
Southern Indiana Gas and Electric Company, Inc.	IN	2009	3,073	144	3,217	1,990	27	38	34	0.8140	0.64758	18,264	141,664	159,929	1.0111
Southern Indiana Gas and Electric Company, Inc.	IN	2010	3,081	147	3,228	1,997	28	36	34	0.8115	0.64817	18,265	145,973	164,238	1.0269
Southern Indiana Gas and Electric Company, Inc.	IN	2011	3,084	147	3,231	1,997	28	37	34	0.8098	0.64754	18,255	145,762	164,016	0.9987
St. Joe Natural Gas Co, Inc.	FL	2007	147	0	147	87	20		21	0.5020	0.59184	765	0	765	
St. Joe Natural Gas Co, Inc.	FL	2008	149	0	149	88	21		21	0.4889	0.59060	772	0	772	1.0096
St. Joe Natural Gas Co, Inc.	FL	2009	150	0	150	88	22		20	0.4701	0.58667	779	0	779	1.0082
St. Joe Natural Gas Co, Inc.	FL	2010	166	0	166	88	25		18	0.4248	0.53012	880	0	880	1.1305
St. Joe Natural Gas Co, Inc.	FL	2011	168	0	168	90	26		17	0.4135	0.53571	882	0	882	1.0023
St. Lawrence Gas Company, Inc.	NY	2007	284	91	375	187	28	34	41	0.9753	0.65845	2,257	28,291	30,548	
St. Lawrence Gas Company, Inc.	NY	2008	287	91	378	188	29	35	41	0.9648	0.65505	2,271	28,291	30,562	1.0004
St. Lawrence Gas Company, Inc.	NY	2009	287	91	378	188	30	36	41	0.9738	0.65505	2,271	28,291	30,562	1.0000
St. Lawrence Gas Company, Inc.	NY	2010	289	91	380	189	31	37	41	0.9720	0.65434	2,298	28,673	30,971	1.0134
St. Lawrence Gas Company, Inc.	NY	2011	291	91	381	191	32	38	41	0.9686	0.65554	2,300	28,673	30,973	1.0001
Superior Water, Light and Power Company	WI	2007	282	8	290	174	22	2	42	0.9940	0.61702	2,012	1,627	3,639	
Superior Water, Light and Power Company	WI	2008	283	8	291	175	23	3	42	0.9949	0.61837	1,959	1,627	3,585	0.9853
Superior Water, Light and Power Company	WI	2009	283	8	291	175	24	4	42	1.0033	0.61837	1,959	1,627	3,585	1.0000
Superior Water, Light and Power Company	WI	2010	284	8	292	176	25	5	42	1.0050	0.61972	1,960	1,627	3,586	1.0003
Superior Water, Light and Power Company	WI	2011	287	8	295	179	25	6	42	0.9948	0.62369	1,963	1,627	3,589	1.0008
Texas Gas Service Company	TX	2007	8,847	522	9,369	5,982	37	49	63	1.4943	0.67616	41,965	378,133	420,099	
Texas Gas Service Company	TX	2008	8,945	520	9,465	6,069	38	50	62	1.4835	0.67848	42,186	376,639	418,825	0.9970
Texas Gas Service Company	TX	2009	9,138	509	9,647	6,110	38	58	63	1.4931	0.66864	44,963	285,536	330,498	0.7891
Texas Gas Service Company	TX	2010	9,368	395	9,763	6,248	37	55	63	1.4973	0.66695	50,257	212,031	262,288	0.7936
Texas Gas Service Company	TX	2011	9,407	391	9,798	6,281	38	57	63	1.5097	0.66769	50,397	211,858	262,255	0.9999
UGI Central Penn Gas, Inc.	PA	2007	3,658	124	3,782	1,834	34	41	20	0.4857	0.50145	39,090	59,675	98,765	
UGI Central Penn Gas, Inc.	PA	2008	3,672	123	3,795	1,845	34	41	20	0.4802	0.50237	26,643	59,557	86,201	0.8728
UGI Central Penn Gas, Inc.	PA	2009	3,682	123	3,805	1,856	38	42	20	0.4744	0.50394	26,690	59,557	86,247	1.0005
UGI Central Penn Gas, Inc.	PA	2010	3,690	111	3,801	1,860	38	43	20	0.4744	0.50402	26,705	54,200	80,904	0.9381
UGI Central Penn Gas, Inc.	PA	2011	3,702	111	3,813	1,864	39	44	20	0.4752	0.50340	26,851	54,200	81,051	1.0018
UGI Utilities, Inc.	PA	2007	5,143	117	5,260	2,302	29	31	61	1.4625	0.44756	47,169	73,795	120,964	
UGI Utilities, Inc.	PA	2008	5,222	117	5,339	2,352	30	32	62	1.4718	0.45052	49,310	73,795	123,104	1.0177
UGI Utilities, Inc.	PA	2009	5,319	117	5,436	2,423	30	33	62	1.4689	0.45556	49,850	73,795	123,645	1.0044
UGI Utilities, Inc.	PA	2010	5,333	117	5,450	2,453	31	34	62	1.4858	0.45997	49,641	73,863	123,503	0.9989
UGI Utilities, Inc.	PA	2011	5,381	117	5,498	2,498	31	35	64	1.5194	0.46423	49,874	73,863	123,736	1.0019
Valley Energy Inc.	NY	2007	30	0	30	8	22		51	1.2252	0.26483	252	0	252	
Valley Energy Inc.	NY	2008	30	0	30	8	23		52	1.2483	0.26548	252	0	252	1.0001
Valley Energy Inc.	NY	2009	31	0	31	9	24		53	1.2547	0.28282	252	0	252	1.0029
Valley Energy Inc.	NY	2010	32	0	32	9	24		53	1.2536	0.27700	265	0	265	1.0487
Valley Energy Inc.	NY	2011	32	0	32	9	25		53	1.2645	0.28105	265	0	265	1.0015
Valley Energy Inc.	PA	2007	135	10	145	47	24	41	37	0.8910	0.34608	1,068	2,033	3,101	
Valley Energy Inc.	PA	2008	136	10	146	47	25	42	38	0.9065	0.34823	1,071	2,033	3,104	1.0009
Valley Energy Inc.	PA	2009	136	10	146	48	25	43	39	0.9314	0.35251	1,071	2,033	3,105	1.0001
Valley Energy Inc.	PA	2010	139	10	149	48	25	44	39	0.9404	0.34987	1,102	2,033	3,136	1.0100
Valley Energy Inc.	PA	2011	141	10	151	49	26	45	39	0.9397	0.34724	1,126	2,033	3,160	1.0076
Vectren Energy Delivery of Ohio, Inc.	OH	2007	5,218	284	5,502	1,771	37	37	57	1.3677	0.33940	52,891	361,959	414,850	
Vectren Energy Delivery of Ohio, Inc.	OH	2008	5,233	284	5,517	1,777	38	38	57	1.3601	0.33958	52,979	361,959	414,938	1.0002
Vectren Energy Delivery of Ohio, Inc.	OH	2009	5,263	269	5,532	1,789	38	40	56	1.3444	0.33992	53,452	357,410	410,862	0.9902
Vectren Energy Delivery of Ohio, Inc.	OH	2010	5,275	269	5,544	1,807	39	41	56	1.3346	0.34256	53,419	357,437	410,857	1.0000

Schedule 2: Natural Gas LDC Data Base

A	B	C	L	M	N	O	P	Q	R	S	T	U	V	W	X
Formula:					L+M				K/(L+M)	Base ≈ 42	O/L			U+V	%Δ in W
Utility	State of Operation	Year	Distribution Miles	Transmission Miles	Total Miles of Pipe	Miles of Distribution Main 2" or less	Average Distribution Age	Average Transmission Age	Density	Density Index	Distribution Customer Factor	Estimated Distribution Capacity	Estimated Transmission Capacity	Total Capacity	% Capacity Change by Year
Vectren Energy Delivery of Ohio, Inc.	OH	2011	5,255	269	5,524	1,825	39	42	56	1.3382	0.34729	53,018	358,046	411,064	1.0005
Vermont Gas Systems, Inc.	VT	2007	627	70	697	417	15	33	57	1.3632	0.66507	2,683	30,436	33,120	
Vermont Gas Systems, Inc.	VT	2008	646	70	716	431	16	34	57	1.3618	0.66718	2,766	30,436	33,202	1.0025
Vermont Gas Systems, Inc.	VT	2009	666	70	736	440	16	35	58	1.3707	0.66066	2,998	30,436	33,435	1.0070
Vermont Gas Systems, Inc.	VT	2010	678	69	747	449	17	36	58	1.3772	0.66224	3,051	31,002	34,053	1.0185
Vermont Gas Systems, Inc.	VT	2011	688	69	756	458	18	37	58	1.3895	0.66557	3,089	30,886	33,975	0.9977
Virginia Natural Gas, Inc.	VA	2007	5,208	156	5,364	3,710	25	12	50	1.1956	0.71237	35,431	401,541	436,972	
Virginia Natural Gas, Inc.	VA	2008	5,195	156	5,351	3,722	26	13	51	1.2079	0.71646	36,584	401,541	438,126	1.0026
Virginia Natural Gas, Inc.	VA	2009	5,244	156	5,400	3,768	26	14	51	1.2028	0.71854	36,635	401,541	438,176	1.0001
Virginia Natural Gas, Inc.	VA	2010	5,295	179	5,474	3,809	27	15	50	1.1972	0.71924	36,754	481,801	518,555	1.1834
Virginia Natural Gas, Inc.	VA	2011	5,309	179	5,487	3,811	26	16	51	1.2072	0.71790	38,310	481,801	520,111	1.0030
Wisconsin Gas LLC	WI	2007	10,355	286	10,641	5,785	26	20	55	1.3165	0.55867	67,276	545,785	613,061	
Wisconsin Gas LLC	WI	2008	10,415	298	10,713	5,814	26	21	55	1.3157	0.55823	67,174	558,762	625,936	1.0210
Wisconsin Gas LLC	WI	2009	10,475	296	10,771	5,844	27	21	55	1.3148	0.55790	67,746	553,664	621,410	0.9928
Wisconsin Gas LLC	WI	2010	10,514	294	10,808	5,891	28	22	55	1.3162	0.56030	67,779	548,523	616,302	0.9918
Wisconsin Gas LLC	WI	2011	10,671	293	10,964	5,967	28	23	55	1.3020	0.55918	71,189	549,323	620,512	1.0068
Wisconsin Power and Light Company	WI	2007	3,825	50	3,875	2,080	23	20	45	1.0746	0.54379	22,404	46,805	69,209	
Wisconsin Power and Light Company	WI	2008	3,863	50	3,913	2,096	23	21	45	1.0751	0.54258	22,720	46,805	69,525	1.0046
Wisconsin Power and Light Company	WI	2009	3,895	50	3,945	2,111	24	22	45	1.0663	0.54198	22,984	46,805	69,789	1.0038
Wisconsin Power and Light Company	WI	2010	3,939	51	3,989	2,128	25	23	45	1.0644	0.54036	23,193	46,445	69,638	0.9978
Wisconsin Power and Light Company	WI	2011	3,997	51	4,048	2,154	25	24	45	1.0604	0.53888	23,628	46,436	70,064	1.0061
Wyoming Gas Company	WY	2007	270	0	270	188	17		25	0.5940	0.69630	968	0	968	
Wyoming Gas Company	WY	2008	276	0	276	194	18		25	0.5848	0.70290	974	0	974	1.0062
Wyoming Gas Company	WY	2009	274	0	274	196	18		25	0.5960	0.71533	914	0	914	0.9379
Wyoming Gas Company	WY	2010	281	0	281	200	19		24	0.5828	0.71174	937	0	937	1.0252
Wyoming Gas Company	WY	2011	287	0	287	207	20		24	0.5710	0.72125	938	0	938	1.0007
Yankee Gas Services Company	CT	2007	3,167	0	3,167	533	39		64	1.5243	0.16833	58,228	0	58,228	
Yankee Gas Services Company	CT	2008	3,181	0	3,181	538	40		64	1.5334	0.16909	58,308	0	58,308	1.0014
Yankee Gas Services Company	CT	2009	3,218	0	3,218	546	40		64	1.5277	0.16968	58,740	0	58,740	1.0074
Yankee Gas Services Company	CT	2010	3,239	0	3,239	549	41		64	1.5135	0.16951	60,717	0	60,717	1.0337
Yankee Gas Services Company	CT	2011	3,256	0	3,256	552	41		64	1.5194	0.16963	62,014	0	62,014	1.0214

Schedule 2: Natural Gas LDC Data Base

A	B	C	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Formula:			D*(1-J)+(G*J)	%Δ in Y	K/S	(AA*T)+[W*(1-T)]	%Δ in AB	AC-Z	%Δ in AD	AE-Z	X-Z	4 Year Average of AD	4 Year Average of K
Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
Alabama Gas Corporation	AL	2007	498,392		451,167	379,535							
Alabama Gas Corporation	AL	2008	517,627	1.0386	459,435	384,759	1.013766216	-0.0248	0.990901374	-0.0477	-0.0299		
Alabama Gas Corporation	AL	2009	544,618	1.0521	465,654	386,546	1.004643547	-0.0475	0.993750308	-0.0584	-0.0615	-0.0316	439,065
Alabama Gas Corporation	AL	2010	572,640	1.0515	466,801	385,217	0.996562687	-0.0549	0.984381049	-0.0671	-0.0673		
Alabama Gas Corporation	AL	2011	571,851	0.9986	469,341	384,964	0.999341399	0.0007	0.977755877	-0.0209	-0.0082		
Atlanta Gas Light Company	GA	2007	1,375,868		1,318,185	1,470,962					0.0000		
Atlanta Gas Light Company	GA	2008	1,438,038	1.0452	1,333,513	1,482,208	1.007645181	-0.0375	0.999070367	-0.0461	-0.0440		
Atlanta Gas Light Company	GA	2009	1,444,957	1.0048	1,339,266	1,446,214	0.975715976	-0.0291	0.972643091	-0.0322	-0.0792	-0.0623	1,523,941
Atlanta Gas Light Company	GA	2010	1,581,954	1.0948	1,343,764	1,449,951	1.002583782	-0.0922	0.998890817	-0.0959	-0.0935		
Atlanta Gas Light Company	GA	2011	1,745,470	1.1034	1,349,806	1,469,047	1.013170075	-0.0902	0.998683366	-0.1047	-0.0741		
Baltimore Gas and Electric Company	MD	2007	574,365		293,863	416,134					0.0000		
Baltimore Gas and Electric Company	MD	2008	588,886	1.0253	296,005	416,817	1.001641676	-0.0236	1.004252646	-0.0210	-0.0249		
Baltimore Gas and Electric Company	MD	2009	574,383	0.9754	296,887	410,749	0.98544154	0.0101	1.002969485	0.0276	0.0025	-0.0400	651,386
Baltimore Gas and Electric Company	MD	2010	625,971	1.0898	298,774	411,334	1.001426149	-0.0884	1.002662627	-0.0872	-0.0904		
Baltimore Gas and Electric Company	MD	2011	662,990	1.0591	300,624	411,821	1.001182274	-0.0580	1.000858114	-0.0583	-0.0588		
Berkshire Gas Company	MA	2007	102,553		30,948	17,183					0.0000		
Berkshire Gas Company	MA	2008	103,549	1.0097	30,990	17,316	1.00774418	-0.0020	1.004652081	-0.0051	0.0198		
Berkshire Gas Company	MA	2009	101,724	0.9824	30,990	17,347	1.001780675	0.0194	1.007577246	0.0252	0.0167	0.0144	35,932
Berkshire Gas Company	MA	2010	100,707	0.9900	31,074	17,398	1.002940793	0.0129	1.001225524	0.0112	0.0231		
Berkshire Gas Company	MA	2011	98,828	0.9813	31,242	17,550	1.008737712	0.0274	1.008262164	0.0269	0.0193		
Bluefield Gas Company	WV	2007	3,972		4,416	2,130					0.0000		
Bluefield Gas Company	WV	2008	4,188	1.0544	4,421	2,138	1.003650345	-0.0507	1.071387115	0.0170	-0.0549		
Bluefield Gas Company	WV	2009	4,363	1.0418	4,421	2,146	1.003938898	-0.0378	0.958829902	-0.0829	-0.0430	-0.0126	3,566
Bluefield Gas Company	WV	2010	4,140	0.9489	4,451	2,171	1.011382713	0.0625	1	0.0511	0.0517		
Bluefield Gas Company	WV	2011	4,249	1.0262	4,455	2,175	1.002028164	-0.0242	0.986440678	-0.0398	-0.0254		
Boston Gas Company	MA	2007	1,077,820		261,440	157,951					0.0000		
Boston Gas Company	MA	2008	865,819	0.8033	262,578	158,531	1.003674602	0.2004	1.044648587	0.2413	0.2004		
Boston Gas Company	MA	2009	938,382	1.0838	263,319	159,037	1.003191632	-0.0806	0.982022392	-0.1018	-0.0801	-0.0345	623,507
Boston Gas Company	MA	2010	1,046,041	1.1147	264,055	159,555	1.003253794	-0.1115	1.004847259	-0.1099	-0.1110		
Boston Gas Company	MA	2011	1,201,019	1.1482	264,499	159,866	1.001951968	-0.1462	1.098934762	-0.0492	-0.1458		
Brainard Gas Corp.	OH	2007	187		714	555					0.0000		
Brainard Gas Corp.	OH	2008	286	1.5314	756	558	1.006118081	-0.5253	1.139534884	-0.3919	-0.3661		
Brainard Gas Corp.	OH	2009	312	1.0900	756	558	1	-0.0900	1.367346939	0.2774	-0.0900	-0.1798	137
Brainard Gas Corp.	OH	2010	390	1.2507	756	558	1	-0.2507	1.126865672	-0.1239	-0.2507		
Brainard Gas Corp.	OH	2011	333	0.8532	756	558	1	0.1468	1.086092715	0.2329	0.1468		
Central Hudson Gas & Electric Corporation	NY	2007	107,676		55,430	79,231					0.0000		
Central Hudson Gas & Electric Corporation	NY	2008	112,424	1.0441	55,724	79,322	1.00114838	-0.0429	1.012948874	-0.0311	-0.0438		
Central Hudson Gas & Electric Corporation	NY	2009	123,786	1.1011	55,934	79,587	1.003345441	-0.0977	1.002575547	-0.0985	-0.1003	-0.0661	74,711
Central Hudson Gas & Electric Corporation	NY	2010	138,276	1.1171	56,312	80,288	1.008805233	-0.1083	1.007841291	-0.1092	-0.1054		
Central Hudson Gas & Electric Corporation	NY	2011	140,845	1.0186	56,639	80,527	1.002981706	-0.0156	1.006232234	-0.0123	-0.0171		
Chattanooga Gas Company	TN	2007	79,450		65,676	47,431					0.0000		
Chattanooga Gas Company	TN	2008	82,486	1.0382	66,726	48,117	1.014445536	-0.0238	0.999299275	-0.0389	-0.0348		
Chattanooga Gas Company	TN	2009	78,669	0.9537	66,768	48,201	1.001753372	0.0480	1.00383223	0.0501	0.0418	-0.0084	61,681
Chattanooga Gas Company	TN	2010	81,597	1.0372	67,153	48,221	1.000417857	-0.0368	1.00308657	-0.0341	-0.0531		
Chattanooga Gas Company	TN	2011	83,038	1.0177	67,167	48,051	0.996475289	-0.0212	1.005652096	-0.0120	-0.0522		
Chesapeake Utilities Corporation	MD	2007	13,771		11,781	6,504					0.0000		
Chesapeake Utilities Corporation	MD	2008	14,101	1.0239	11,931	6,680	1.027083929	0.0031	1.007420696	-0.0165	-0.0267		
Chesapeake Utilities Corporation	MD	2009	15,494	1.0987	12,315	6,862	1.027273993	-0.0715	1.003318763	-0.0954	-0.0197	-0.0501	12,388
Chesapeake Utilities Corporation	MD	2010	16,293	1.0516	12,343	6,888	1.003757476	-0.0478	0.996772892	-0.0548	-0.0562		
Chesapeake Utilities Corporation	MD	2011	17,645	1.0830	12,300	6,880	0.998810652	-0.0842	1.007365439	-0.0756	-0.0805		
Cheyenne Light, Fuel and Power Company	WY	2007	20,299		31,872	28,131					0.0000		
Cheyenne Light, Fuel and Power Company	WY	2008	26,878	1.3241	32,440	28,650	1.018448964	-0.3056	1.007662951	-0.3164	-0.3076		
Cheyenne Light, Fuel and Power Company	WY	2009	27,580	1.0261	32,524	28,725	1.00261821	-0.0235	1.008746881	-0.0174	-0.0260	-0.1119	33,892
Cheyenne Light, Fuel and Power Company	WY	2010	28,335	1.0274	32,834	28,978	1.008808616	-0.0185	1.01647795	-0.0109	-0.0265		
Cheyenne Light, Fuel and Power Company	WY	2011	31,352	1.1065	33,221	29,170	1.006617926	-0.0999	1.015038255	-0.0915	-0.1040		
Citizens Gas Fuel Company	MI	2007	10,373		19,652	9,444					0.0000		
Citizens Gas Fuel Company	MI	2008	9,673	0.9325	19,694	8,435	0.893181434	-0.0394	0.996850577	0.0643	-0.1646		
Citizens Gas Fuel Company	MI	2009	9,583	0.9907	19,778	8,508	1.00864679	0.0179	1.001521179	0.0108	0.0097	-0.0238	17,145
Citizens Gas Fuel Company	MI	2010	10,160	1.0602	19,820	8,515	1.000810732	-0.0594	1.003154574	-0.0571	-0.0588		
Citizens Gas Fuel Company	MI	2011	10,306	1.0143	19,820	8,515	1	-0.0143	1.001455858	-0.0129	-0.0143		
Colonial Gas Company	MA	2007	462,696		58,050	36,315					0.0000		
Colonial Gas Company	MA	2008	345,902	0.7476	58,234	36,452	1.003771811	0.2562	1.050766124	0.3032	0.2557		
Colonial Gas Company	MA	2009	311,750	0.9013	58,372	36,536	1.002307067	0.1010	0.98394479	0.0827	0.1017	0.1025	192,154
Colonial Gas Company	MA	2010	328,707	1.0544	58,453	36,561	1.000665804	-0.0537	0.994239775	-0.0602	-0.0580		
Colonial Gas Company	MA	2011	294,519	0.8960	58,644	36,657	1.002644565	0.1067	0.976544265	0.0806	0.1071		
Colorado Natural Gas, Inc.	CO	2007	42,858		21,521	16,023					0.0000		
Colorado Natural Gas, Inc.	CO	2008	57,623	1.3445	26,976	20,177	1.259203039	-0.0853	1.058341996	-0.2862	-0.1391		

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Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
Colorado Natural Gas, Inc.	CO	2009	69,875	1.2126	32,872	23,850	1.182063011	-0.0306	1.335297729	0.1227	0.1882	-0.0457	12,141
Colorado Natural Gas, Inc.	CO	2010	79,095	1.1319	35,055	24,255	1.016979934	-0.1150	1.171386539	0.0394	0.0216		
Colorado Natural Gas, Inc.	CO	2011	86,754	1.0968	38,654	27,772	1.14499368	0.0482	1.31899529	0.2222	-0.1118		
Columbia Gas of Kentucky, Incorporated	KY	2007	99,272		108,676	104,587					0.0000		
Columbia Gas of Kentucky, Incorporated	KY	2008	102,331	1.0308	109,554	105,202	1.005883379	-0.0249	0.991643655	-0.0392	-0.0263		
Columbia Gas of Kentucky, Incorporated	KY	2009	99,365	0.9710	109,848	105,325	1.001174499	0.0302	0.985945702	0.0149	0.0290	-0.0384	135,571
Columbia Gas of Kentucky, Incorporated	KY	2010	107,191	1.0788	110,142	105,311	0.999864981	-0.0789	0.994572472	-0.0842	-0.0807		
Columbia Gas of Kentucky, Incorporated	KY	2011	115,335	1.0760	109,323	104,907	0.996161988	-0.0798	0.995573482	-0.0804	-0.0783		
Columbia Gas of Maryland, Incorporated	MD	2007	38,277		26,917	16,463					0.0000		
Columbia Gas of Maryland, Incorporated	MD	2008	39,041	1.0200	27,165	16,515	1.003173048	-0.0168	0.994177138	-0.0258	-0.0296		
Columbia Gas of Maryland, Incorporated	MD	2009	39,557	1.0132	27,501	16,682	1.010109551	-0.0031	0.998458693	-0.0148	-0.0070	-0.0661	32,387
Columbia Gas of Maryland, Incorporated	MD	2010	44,751	1.1313	27,501	16,687	1.000281004	-0.1310	0.998548935	-0.1328	-0.1369		
Columbia Gas of Maryland, Incorporated	MD	2011	49,471	1.1055	27,085	16,555	0.992084724	-0.1134	1.001020314	-0.1045	-0.1280		
Columbia Gas of Ohio, Incorporated	OH	2007	881,664		832,878	541,691					0.0000		
Columbia Gas of Ohio, Incorporated	OH	2008	822,390	0.9328	832,257	545,763	1.007517894	0.0747	0.995317105	0.0625	0.0905		
Columbia Gas of Ohio, Incorporated	OH	2009	990,574	1.2045	834,063	547,399	1.002997358	-0.2015	0.997351384	-0.2072	-0.2043	-0.0771	1,398,810
Columbia Gas of Ohio, Incorporated	OH	2010	1,062,415	1.0725	835,322	548,496	1.002004195	-0.0705	0.998062576	-0.0745	-0.0732		
Columbia Gas of Ohio, Incorporated	OH	2011	1,181,472	1.1121	842,222	549,048	1.001006937	-0.1111	0.999873261	-0.1122	-0.1442		
Columbia Gas of Pennsylvania, Inc.	PA	2007	318,130		310,072	186,398					0.0000		
Columbia Gas of Pennsylvania, Inc.	PA	2008	366,127	1.1509	310,173	186,191	0.99888998	-0.1520	1.003083793	-0.1478	-0.1575		
Columbia Gas of Pennsylvania, Inc.	PA	2009	411,070	1.1228	311,840	189,226	1.016298509	-0.1065	1.000882531	-0.1219	-0.0954	-0.0988	413,866
Columbia Gas of Pennsylvania, Inc.	PA	2010	414,141	1.0075	312,869	191,247	1.010682753	0.0032	1.004047828	-0.0034	0.0121		
Columbia Gas of Pennsylvania, Inc.	PA	2011	463,772	1.1198	309,623	187,371	0.97973206	-0.1401	1.002969951	-0.1169	-0.1593		
Columbia Gas of Virginia, Incorporated	VA	2007	271,238		201,984	144,380					0.0000		
Columbia Gas of Virginia, Incorporated	VA	2008	301,645	1.1121	203,987	145,471	1.007558991	-0.1045	1.007448338	-0.1047	-0.1197		
Columbia Gas of Virginia, Incorporated	VA	2009	314,654	1.0431	206,036	146,482	1.006950135	-0.0362	1.00711882	-0.0360	-0.0431	-0.0174	239,719
Columbia Gas of Virginia, Incorporated	VA	2010	344,137	1.0937	208,850	169,915	1.15997018	0.0663	1.00912281	-0.0846	0.6241		
Columbia Gas of Virginia, Incorporated	VA	2011	340,611	0.9898	208,493	169,000	0.994616571	0.0049	1.008795217	0.0190	0.0130		
Connecticut Natural Gas Corporation	CT	2007	396,457		84,195	47,705					0.0000		
Connecticut Natural Gas Corporation	CT	2008	374,465	0.9445	84,489	47,848	1.003005414	0.0585	1.019970299	0.0754	0.0469		
Connecticut Natural Gas Corporation	CT	2009	303,231	0.8098	84,447	47,792	0.998818473	0.1890	1.002656551	0.1929	0.1840	0.0884	158,137
Connecticut Natural Gas Corporation	CT	2010	289,206	0.9537	84,825	48,038	1.005160142	0.0514	1.011164894	0.0574	0.0483		
Connecticut Natural Gas Corporation	CT	2011	274,591	0.9495	84,909	48,232	1.00402592	0.0546	1.008937851	0.0595	0.0478		
Consolidated Edison Company of New York, Inc.	NY	2007	1,807,401		181,071	278,715					0.0000		
Consolidated Edison Company of New York, Inc.	NY	2008	1,947,217	1.0774	181,449	279,326	1.002194042	-0.0752	0.902450929	-0.1749	-0.0748		
Consolidated Edison Company of New York, Inc.	NY	2009	2,094,100	1.0754	181,869	279,869	1.001942682	-0.0735	0.990337066	-0.0851	-0.0731	-0.0679	1,063,562
Consolidated Edison Company of New York, Inc.	NY	2010	2,211,394	1.0560	182,163	281,231	1.004868251	-0.0511	1.003519477	-0.0525	-0.0507		
Consolidated Edison Company of New York, Inc.	NY	2011	2,372,037	1.0726	183,003	281,512	1.000999572	-0.0716	1.002718146	-0.0699	-0.0715		
Consumers Energy Company	MI	2007	1,124,650		1,190,402	2,713,277					0.0000		
Consumers Energy Company	MI	2008	1,130,935	1.0056	1,192,334	2,710,704	0.999051986	-0.0065	0.998607092	-0.0070	-0.0066		
Consumers Energy Company	MI	2009	1,215,550	1.0748	1,198,759	2,683,609	0.990004307	-0.0848	1.010662988	-0.0642	-0.0907	-0.0542	1,710,772
Consumers Energy Company	MI	2010	1,361,765	1.1203	1,198,759	2,758,995	1.028091241	-0.0922	0.988335547	-0.1320	-0.0804		
Consumers Energy Company	MI	2011	1,399,226	1.0275	1,202,559	2,743,346	0.994328056	-0.0332	1.002131011	-0.0254	-0.0340		
Corning Natural Gas Corporation	NY	2007	11,914		13,648	8,238					0.0000		
Corning Natural Gas Corporation	NY	2008	15,090	1.2666	15,953	11,087	1.345877565	0.0793	1.003439499	-0.2632	0.1447		
Corning Natural Gas Corporation	NY	2009	17,802	1.1797	17,271	11,760	1.060651665	-0.1191	1.000137108	-0.1796	-0.1128	-0.1021	14,664
Corning Natural Gas Corporation	NY	2010	21,021	1.1808	17,280	10,580	0.899677422	-0.2811	1.007608472	-0.1732	-0.3586		
Corning Natural Gas Corporation	NY	2011	23,223	1.1048	17,309	10,762	1.017156862	-0.0876	1.00537415	-0.0994	-0.0945		
Delta Natural Gas Company, Inc.	KY	2007	77,312		80,961	85,502					0.0000		
Delta Natural Gas Company, Inc.	KY	2008	79,177	1.0241	81,255	85,719	1.002535777	-0.0216	0.981108142	-0.0430	-0.0239		
Delta Natural Gas Company, Inc.	KY	2009	79,051	0.9984	81,843	86,176	1.005328255	0.0069	0.988446621	-0.0100	0.0021	-0.0914	35,904
Delta Natural Gas Company, Inc.	KY	2010	86,087	1.0890	82,229	71,226	0.826523999	-0.2625	0.997439679	-0.0916	-0.5343		
Delta Natural Gas Company, Inc.	KY	2011	93,876	1.0905	82,455	71,369	1.002002567	-0.0885	0.990123043	-0.1004	-0.0902		
DTE Gas Company	MI	2007	1,041,448		874,703	4,077,427					0.0000		
DTE Gas Company	MI	2008	1,107,799	1.0637	877,684	3,525,928	0.864743317	-0.1990	0.990715022	-0.0730	-0.2119		
DTE Gas Company	MI	2009	1,136,049	1.0255	877,390	4,085,048	1.158573728	0.1331	0.987684038	-0.0378	0.1708	-0.0534	1,223,523
DTE Gas Company	MI	2010	1,247,800	1.0984	876,131	4,072,812	0.997004872	-0.1014	0.991786821	-0.1066	-0.1008		
DTE Gas Company	MI	2011	1,303,461	1.0446	878,860	4,064,943	0.998067815	-0.0465	0.998383756	-0.0462	-0.0458		
Duke Energy Kentucky, Inc.	KY	2007	122,191		59,467	111,980					0.0000		
Duke Energy Kentucky, Inc.	KY	2008	130,876	1.0711	59,504	111,575	0.996384589	-0.0747	1.006372518	-0.0647	-0.0713		
Duke Energy Kentucky, Inc.	KY	2009	177,303	1.3547	59,590	108,410	0.971627104	-0.3831	0.996896819	-0.3578	-0.3874	-0.1561	95,122
Duke Energy Kentucky, Inc.	KY	2010	223,163	1.2587	59,444	108,273	0.998736509	-0.2599	0.999127143	-0.2595	-0.2576		
Duke Energy Kentucky, Inc.	KY	2011	209,148	0.9372	59,650	111,561	1.030369251	0.0932	0.999957898	0.0628	0.1008		
Duke Energy Ohio, Inc.	OH	2007	551,679		238,756	284,124					0.0000		
Duke Energy Ohio, Inc.	OH	2008	682,123	1.2364	238,498	278,901	0.981616302	-0.2548	1.001737611	-0.2347	-0.2614		
Duke Energy Ohio, Inc.	OH	2009	758,999	1.1127	241,560	294,585	1.056237489	-0.0565	0.990876867	-0.1218	-0.0343	-0.0971	420,086
Duke Energy Ohio, Inc.	OH	2010	766,539	1.0099	241,875	293,668	0.996886457	-0.0130	0.994536611	-0.0154	-0.0129		

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A	B	C	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Formula:			D*(1-J)+(G*J)	%Δ in Y	K/S	(AA*T)+[W*(1-T)]	%Δ in AB	AC-Z	%Δ in AD	AE-Z	X-Z	4 Year Average of AD	4 Year Average of K
Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
Duke Energy Ohio, Inc.	**OH**	**2011**	796,779	1.0394	241,302	286,402	0.975259003	-0.0642	0.998392875	-0.0411	-0.0729		
East Ohio Gas Company	**OH**	**2007**	882,593		854,463	3,582,185					0.0000		
East Ohio Gas Company	**OH**	**2008**	963,945	1.0922	855,344	3,574,030	0.997723673	-0.0945	0.992944306	-0.0992	-0.0951		
East Ohio Gas Company	**OH**	**2009**	1,014,452	1.0524	856,016	3,576,719	1.000752313	-0.0516	0.993761587	-0.0586	-0.0522	-0.1039	1,190,878
East Ohio Gas Company	**OH**	**2010**	1,109,985	1.0942	857,388	3,570,039	0.998132324	-0.0960	0.993945248	-0.1002	-0.0968		
East Ohio Gas Company	**OH**	**2011**	1,233,492	1.1113	854,147	3,347,549	0.937678437	-0.1736	0.996106342	-0.1152	-0.1764		
Eastern Natural Gas Company	**OH**	**2007**	2,242		9,658	4,533					0.0000		
Eastern Natural Gas Company	**OH**	**2008**	2,357	1.0512	9,700	4,573	1.008676642	-0.0426	0.994285714	-0.0569	-0.0504		
Eastern Natural Gas Company	**OH**	**2009**	2,179	0.9246	9,658	4,533	0.991397995	0.0668	0.99092559	0.0663	0.0746	-0.0046	6,560
Eastern Natural Gas Company	**OH**	**2010**	2,227	1.0217	9,658	4,559	1.005712454	-0.0160	1.001831502	-0.0199	-0.0360		
Eastern Natural Gas Company	**OH**	**2011**	2,321	1.0425	9,700	4,632	1.015990759	-0.0265	0.991925655	-0.0506	-0.0461		
Empire District Gas Company	**MO**	**2007**	31,027		50,171	40,264					0.0000		
Empire District Gas Company	**MO**	**2008**	35,337	1.1389	50,399	40,405	1.003507363	-0.1354	0.973078848	-0.1658	-0.1371		
Empire District Gas Company	**MO**	**2009**	32,487	0.9194	50,597	40,523	1.002914472	0.0836	0.986916264	0.0676	0.0813	-0.0940	44,204
Empire District Gas Company	**MO**	**2010**	41,771	1.2858	50,924	40,743	1.005424107	-0.2803	1.00815827	-0.2776	-0.2849		
Empire District Gas Company	**MO**	**2011**	43,723	1.0467	51,101	40,858	1.002817741	-0.0439	0.977544002	-0.0692	-0.0462		
Energy West, Incorporated	**WY**	**2007**	5,284		14,529	13,586					0.0000		
Energy West, Incorporated	**WY**	**2008**	5,754	1.0889	14,781	13,802	1.015893666	-0.0730	1.019834173	-0.0691	-0.0865		
Energy West, Incorporated	**WY**	**2009**	5,692	0.9892	15,411	14,113	1.022563442	0.0334	1.016419576	0.0272	0.0256	0.0058	6,410
Energy West, Incorporated	**WY**	**2010**	5,371	0.9437	15,579	14,337	1.015868755	0.0722	1.013801757	0.0701	0.0549		
Energy West, Incorporated	**WY**	**2011**	5,700	1.0612	16,503	15,083	1.051992184	-0.0092	1.009436881	-0.0518	-0.0508		
Fitchburg Gas and Electric Light Company	**MA**	**2007**	32,584		11,073	4,557					0.0000		
Fitchburg Gas and Electric Light Company	**MA**	**2008**	39,650	1.2169	11,103	4,597	1.008827254	-0.2080	1.006613319	-0.2102	-0.2087		
Fitchburg Gas and Electric Light Company	**MA**	**2009**	20,629	0.5203	11,042	4,588	0.998088839	0.4778	1.002430852	0.4821	0.4707	-0.1825	15,287
Fitchburg Gas and Electric Light Company	**MA**	**2010**	34,816	1.6877	11,049	4,596	1.001744505	-0.6859	1.000983091	-0.6867	-0.6851		
Fitchburg Gas and Electric Light Company	**MA**	**2011**	45,846	1.3168	11,047	4,611	1.003129486	-0.3137	1.007922478	-0.3089	-0.3126		
Florida Public Utilities Company	**FL**	**2007**	50,932		67,650	46,598					0.0000		
Florida Public Utilities Company	**FL**	**2008**	51,374	1.0087	68,826	47,387	1.01693651	0.0083	1.000153737	-0.0085	0.0016		
Florida Public Utilities Company	**FL**	**2009**	55,796	1.0861	68,532	47,277	0.997675107	-0.0884	0.993544048	-0.0925	-0.0897	-0.0492	52,221
Florida Public Utilities Company	**FL**	**2010**	59,900	1.0735	69,854	48,216	1.019869064	-0.0537	1.008818581	-0.0647	-0.0603		
Florida Public Utilities Company	**FL**	**2011**	64,684	1.0799	71,281	49,026	1.016794194	-0.0631	1.015297613	-0.0646	-0.0460		
Hope Gas, Inc.	**WV**	**2007**	101,323		123,626	68,248					0.0000		
Hope Gas, Inc.	**WV**	**2008**	102,524	1.0119	127,507	70,878	1.038533497	0.0267	0.996116962	-0.0157	-0.0336		
Hope Gas, Inc.	**WV**	**2009**	104,628	1.0205	128,949	71,483	1.008537384	-0.0120	0.996040506	-0.0245	-0.0039	-0.0419	113,704
Hope Gas, Inc.	**WV**	**2010**	119,707	1.1441	129,432	71,760	1.003873843	-0.1402	0.997959614	-0.1462	-0.1335		
Hope Gas, Inc.	**WV**	**2011**	124,651	1.0413	130,779	71,705	0.999222315	-0.0421	1.000114566	-0.0412	-0.0607		
Illinois Gas Company	**IL**	**2007**	5,059		14,873	9,668					0.0000		
Illinois Gas Company	**IL**	**2008**	5,086	1.0053	14,751	9,632	0.996317968	-0.0090	0.992665784	-0.0127	-0.0143		
Illinois Gas Company	**IL**	**2009**	4,567	0.8980	14,827	9,718	1.008945838	0.1109	0.997639815	0.0996	0.1020	0.0228	9,722
Illinois Gas Company	**IL**	**2010**	4,668	1.0221	14,872	9,763	1.00461017	-0.0175	1.000514297	-0.0216	-0.0215		
Illinois Gas Company	**IL**	**2011**	4,671	1.0006	15,062	9,836	1.007474355	0.0068	0.996607382	-0.0040	0.0147		
Indiana Gas Company, Inc.	**IN**	**2007**	540,012		541,829	566,704					0.0000		
Indiana Gas Company, Inc.	**IN**	**2008**	567,828	1.0515	544,180	580,107	1.023650288	-0.0279	1.002514435	-0.0490	-0.0029		
Indiana Gas Company, Inc.	**IN**	**2009**	553,210	0.9743	546,294	574,960	0.991127169	0.0169	0.996491829	0.0222	0.0023	-0.0004	561,217
Indiana Gas Company, Inc.	**IN**	**2010**	554,018	1.0015	547,313	575,894	1.001624723	0.0002	1.004343408	0.0029	0.0003		
Indiana Gas Company, Inc.	**IN**	**2011**	556,040	1.0036	551,348	583,258	1.012786809	0.0091	1.003581886	-0.0001	0.0166		
Intermountain Gas Company	**ID**	**2007**	135,914		247,504	230,540					0.0000		
Intermountain Gas Company	**ID**	**2008**	146,027	1.0744	255,440	236,479	1.025760792	-0.0486	1.051377448	-0.0230	-0.0739		
Intermountain Gas Company	**ID**	**2009**	144,502	0.9896	260,479	240,331	1.016289336	0.0267	1.019228907	0.0297	0.0149	-0.0244	306,635
Intermountain Gas Company	**ID**	**2010**	148,739	1.0293	263,125	242,241	1.007947055	-0.0214	1.012469334	-0.0169	-0.0277		
Intermountain Gas Company	**ID**	**2011**	153,731	1.0336	263,305	237,250	0.979399521	-0.0542	1.011157624	-0.0224	-0.1455		
Kansas Gas Service Company	**KS**	**2007**	587,075		533,178	873,775					0.0000		
Kansas Gas Service Company	**KS**	**2008**	581,055	0.9897	532,170	872,211	0.998210503	0.0085	0.988946799	-0.0008	0.0104		
Kansas Gas Service Company	**KS**	**2009**	595,973	1.0257	534,186	872,595	1.000440388	-0.0252	1.003050648	-0.0226	-0.0265	-0.0131	632,421
Kansas Gas Service Company	**KS**	**2010**	633,838	1.0635	539,586	877,761	1.005919971	-0.0576	0.997720945	-0.0658	-0.0602		
Kansas Gas Service Company	**KS**	**2011**	617,605	0.9744	539,625	874,674	0.996483336	0.0221	1.000180336	0.0258	0.0218		
KeySpan Gas East Corporation	**NY**	**2007**	1,424,846		177,582	698,777					0.0000		
KeySpan Gas East Corporation	**NY**	**2008**	1,526,768	1.0715	177,989	709,348	1.015126996	-0.0564	1.007576097	-0.0640	-0.0562		
KeySpan Gas East Corporation	**NY**	**2009**	1,581,816	1.0361	179,434	717,507	1.011502574	-0.0246	1.014140789	-0.0219	-0.0246	-0.0260	547,550
KeySpan Gas East Corporation	**NY**	**2010**	1,596,264	1.0091	180,530	716,226	0.998214713	-0.0109	1.006169126	-0.0030	-0.0089		
KeySpan Gas East Corporation	**NY**	**2011**	1,623,471	1.0170	181,117	719,836	1.005040386	-0.0120	1.006193087	-0.0109	-0.0118		
Laclede Gas Company	**MO**	**2007**	574,818		358,784	411,784					0.0000		
Laclede Gas Company	**MO**	**2008**	598,901	1.0419	362,395	413,845	1.005005084	-0.0369	0.998930312	-0.0430	-0.0415		
Laclede Gas Company	**MO**	**2009**	601,363	1.0041	362,815	413,912	1.000162053	-0.0039	0.998728677	-0.0054	-0.0045	-0.0303	641,470
Laclede Gas Company	**MO**	**2010**	612,455	1.0184	364,663	415,122	1.002923974	-0.0155	0.997709327	-0.0207	-0.0182		
Laclede Gas Company	**MO**	**2011**	652,053	1.0647	364,956	415,052	0.999830345	-0.0648	0.996230117	-0.0684	-0.0652		
Louisville Gas and Electric Company	**KY**	**2007**	243,700		192,116	337,997					0.0000		

Schedule 2: Natural Gas LDC Data Base

A	B	C	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Formula:			D*(1-J)+(G*J)	%Δ in Y	K/S	(AA*T)+[W*(1-T)]	%Δ in AB	AC-Z	%Δ in AD	AE-Z	X-Z	4 Year Average of AD	4 Year Average of K
Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
Louisville Gas and Electric Company	**KY**	**2008**	257,079	1.0549	193,291	337,973	0.999929273	-0.0550	0.964000713	-0.0909	-0.0555	-0.1064	317,268
Louisville Gas and Electric Company	**KY**	**2009**	255,048	0.9921	194,173	339,630	1.004902918	0.0128	1.00688563	0.0148	0.0161		
Louisville Gas and Electric Company	**KY**	**2010**	325,872	1.2777	193,532	337,194	0.992826025	-0.2849	1.014442901	-0.2632	-0.2818		
Louisville Gas and Electric Company	**KY**	**2011**	357,885	1.0982	195,882	337,063	0.999612949	-0.0986	0.994054285	-0.1042	-0.0972		
Madison Gas and Electric Company	**WI**	**2007**	76,732		100,698	63,254					0.0000		
Madison Gas and Electric Company	**WI**	**2008**	87,033	1.1342	101,916	64,082	1.01307932	-0.1212	1.016933438	-0.1173	-0.1273	-0.0405	142,769
Madison Gas and Electric Company	**WI**	**2009**	89,783	1.0316	102,840	64,618	1.008372934	-0.0232	1.006332648	-0.0253	-0.0013		
Madison Gas and Electric Company	**WI**	**2010**	83,388	0.9288	103,385	64,928	1.004794453	0.0760	1.005372757	0.0766	0.0782		
Madison Gas and Electric Company	**WI**	**2011**	91,497	1.0973	104,057	65,164	1.003630011	-0.0936	1.006287111	-0.0910	-0.0874		
Michigan Gas Utilities Corporation	**MI**	**2007**	90,896		157,332	123,951					0.0000		
Michigan Gas Utilities Corporation	**MI**	**2008**	91,906	1.0111	158,655	123,289	0.994659409	-0.0164	0.998105221	-0.0130	-0.0416	-0.0162	164,738
Michigan Gas Utilities Corporation	**MI**	**2009**	97,432	1.0601	159,828	124,123	1.006763969	-0.0534	0.999525406	-0.0606	-0.0595		
Michigan Gas Utilities Corporation	**MI**	**2010**	96,509	0.9905	160,852	124,598	1.003827533	0.0133	1.003159375	0.0126	0.0090		
Michigan Gas Utilities Corporation	**MI**	**2011**	97,679	1.0121	161,894	125,080	1.003871139	-0.0083	1.004508714	-0.0076	-0.0091		
Midwest Energy, Inc.	**KS**	**2007**	24,401		127,837	103,966					0.0000		
Midwest Energy, Inc.	**KS**	**2008**	25,386	1.0404	128,673	104,783	1.007853619	-0.0325	1.004601523	-0.0358	-0.0394	-0.0315	41,671
Midwest Energy, Inc.	**KS**	**2009**	25,520	1.0053	128,206	104,329	0.995666518	-0.0096	0.999760186	-0.0055	-0.0058		
Midwest Energy, Inc.	**KS**	**2010**	26,017	1.0195	126,893	102,916	0.986463401	-0.0330	0.998344887	-0.0212	-0.0173		
Midwest Energy, Inc.	**KS**	**2011**	26,606	1.0226	123,685	100,033	0.971983716	-0.0507	1.001297453	-0.0213	-0.0284		
Midwest Natural Gas Corporation	**IN**	**2007**	7,956		24,860	16,295					0.0000		
Midwest Natural Gas Corporation	**IN**	**2008**	9,078	1.1410	24,944	16,341	1.00282279	-0.1382	0.982243634	-0.1588	-0.1386	-0.0342	14,076
Midwest Natural Gas Corporation	**IN**	**2009**	8,548	0.9416	24,944	16,341	1	0.0584	0.987387892	0.0457	0.0584		
Midwest Natural Gas Corporation	**IN**	**2010**	8,650	1.0119	24,524	16,329	0.999240068	-0.0126	0.994677831	-0.0172	-0.0260		
Midwest Natural Gas Corporation	**IN**	**2011**	9,092	1.0511	24,608	16,440	1.006785554	-0.0443	0.993222516	-0.0579	-0.0562		
Midwest Natural Gas, Inc.	**WI**	**2007**	12,069		25,402	17,564					0.0000		
Midwest Natural Gas, Inc.	**WI**	**2008**	10,916	0.9045	25,766	17,839	1.015651422	0.1112	1.017109313	0.1126	0.1053	0.0212	14,494
Midwest Natural Gas, Inc.	**WI**	**2009**	11,174	1.0237	25,867	17,875	1.002012617	-0.0217	1.011683559	-0.0120	-0.0157		
Midwest Natural Gas, Inc.	**WI**	**2010**	11,560	1.0345	26,430	18,202	1.018325437	-0.0162	1.015792403	-0.0187	-0.0130		
Midwest Natural Gas, Inc.	**WI**	**2011**	11,683	1.0107	26,913	18,606	1.022172347	0.0115	1.013012807	0.0024	-0.0007		
Missouri Gas Energy	**MO**	**2007**	473,959		357,305	259,154					0.0000		
Missouri Gas Energy	**MO**	**2008**	465,304	0.9817	359,357	260,242	1.004199763	0.0225	0.996840886	0.0151	0.0188	0.0067	496,529
Missouri Gas Energy	**MO**	**2009**	462,557	0.9941	360,370	260,710	1.001797292	0.0077	0.996510963	0.0024	0.0058		
Missouri Gas Energy	**MO**	**2010**	474,683	1.0262	360,654	260,660	0.99980624	-0.0264	0.994775208	-0.0314	-0.0283		
Missouri Gas Energy	**MO**	**2011**	463,608	0.9767	360,722	260,619	0.999844717	0.0232	0.991942137	0.0153	0.0213		
Mobile Gas Service Corporation	**AL**	**2007**	94,416		95,071	85,908					0.0000		
Mobile Gas Service Corporation	**AL**	**2008**	96,568	1.0228	96,205	86,648	1.008615487	-0.0142	0.994771868	-0.0280	-0.0220	-0.0193	91,076
Mobile Gas Service Corporation	**AL**	**2009**	98,677	1.0218	96,121	86,580	0.999218135	-0.0226	0.980315551	-0.0415	-0.0219		
Mobile Gas Service Corporation	**AL**	**2010**	98,418	0.9974	96,278	86,525	0.999366014	0.0020	0.994726211	-0.0027	-0.0067		
Mobile Gas Service Corporation	**AL**	**2011**	100,032	1.0164	96,471	84,288	0.974147371	-0.0422	0.968057781	-0.0483	-0.1345		
Mountaineer Gas Company	**WV**	**2007**	135,718		209,878	109,013					0.0000		
Mountaineer Gas Company	**WV**	**2008**	140,299	1.0338	217,521	111,873	1.026232825	-0.0075	1.003265123	-0.0305	-0.0582	0.0243	218,641
Mountaineer Gas Company	**WV**	**2009**	136,889	0.9757	221,888	115,282	1.030472403	0.0548	0.98687277	0.0112	0.0314		
Mountaineer Gas Company	**WV**	**2010**	141,546	1.0340	236,779	126,270	1.095309326	0.0613	1.00308101	-0.0309	-0.0102		
Mountaineer Gas Company	**WV**	**2011**	142,233	1.0049	237,467	125,474	0.99369788	-0.0112	1.014231194	0.0094	-0.0677		
Mt. Carmel Public Utility Company	**IL**	**2007**	1,167		4,367	2,386					0.0000		
Mt. Carmel Public Utility Company	**IL**	**2008**	1,497	1.2829	4,367	2,386	1	-0.2829	0.997507616	-0.2854	-0.2829	-0.0908	3,564
Mt. Carmel Public Utility Company	**IL**	**2009**	1,667	1.1133	4,371	2,390	1.001633201	-0.1117	0.992226541	-0.1211	-0.1132		
Mt. Carmel Public Utility Company	**IL**	**2010**	1,770	1.0616	4,386	2,399	1.003640538	-0.0579	0.991885842	-0.0697	-0.0600		
Mt. Carmel Public Utility Company	**IL**	**2011**	1,615	0.9123	4,389	2,403	1.001737504	0.0894	0.996897038	0.0846	0.0869		
National Fuel Gas Distribution Corporation	**PA**	**2007**	200,514		209,038	131,382					0.0000		
National Fuel Gas Distribution Corporation	**PA**	**2008**	205,286	1.0238	208,996	131,814	1.003288558	-0.0205	1.002068545	-0.0217	-0.0285	-0.0140	212,093
National Fuel Gas Distribution Corporation	**PA**	**2009**	207,059	1.0086	208,871	132,300	1.003689907	-0.0049	0.997799049	-0.0108	-0.0135		
National Fuel Gas Distribution Corporation	**PA**	**2010**	208,613	1.0075	208,418	132,811	1.003856297	-0.0036	1.002734822	-0.0048	-0.0034		
National Fuel Gas Distribution Corporation	**PA**	**2011**	214,615	1.0288	208,281	133,055	1.001841965	-0.0269	0.999481848	-0.0293	-0.0308		
New Jersey Natural Gas Company	**NJ**	**2007**	659,222		286,934	339,092					0.0000		
New Jersey Natural Gas Company	**NJ**	**2008**	709,167	1.0758	288,740	345,063	1.017607682	-0.0582	1.011143423	-0.0646	-0.0463	-0.0446	491,581
New Jersey Natural Gas Company	**NJ**	**2009**	743,327	1.0482	291,008	346,780	1.004975633	-0.0432	1.005976272	-0.0422	-0.0468		
New Jersey Natural Gas Company	**NJ**	**2010**	791,221	1.0644	293,947	348,990	1.006374282	-0.0581	1.009180072	-0.0553	-0.0623		
New Jersey Natural Gas Company	**NJ**	**2011**	841,372	1.0634	297,078	364,482	1.044391085	-0.0190	1.00865886	-0.0547	0.0194		
New York State Electric & Gas Corporation	**NY**	**2007**	381,398		198,414	158,354					0.0000		
New York State Electric & Gas Corporation	**NY**	**2008**	383,319	1.0050	199,338	158,924	1.003598889	-0.0014	1.007540339	0.0025	-0.0028	0.0327	260,267
New York State Electric & Gas Corporation	**NY**	**2009**	371,430	0.9690	200,304	159,434	1.003210309	0.0342	1.005188894	0.0362	0.0310		
New York State Electric & Gas Corporation	**NY**	**2010**	366,243	0.9860	200,795	159,473	1.000248191	0.0142	1.003912901	0.0179	0.0115		
New York State Electric & Gas Corporation	**NY**	**2011**	337,479	0.9215	201,315	160,290	1.005118689	0.0837	0.99891264	0.0775	0.0836		
Niagara Mohawk Power Corporation	**NY**	**2007**	772,312		368,946	667,233					0.0000		
Niagara Mohawk Power Corporation	**NY**	**2008**	741,832	0.9605	368,148	661,794	0.991848873	0.0313	1.007927805	0.0474	0.0337	-0.0075	580,947
Niagara Mohawk Power Corporation	**NY**	**2009**	717,483	0.9672	368,890	660,049	0.997362618	0.0302	1.007392758	0.0402	0.0327		

Schedule 2: Natural Gas LDC Data Base

A	B	C	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Formula:			D*(1-J)+(G*J)	%Δ in Y	K/S	(AA*T)+[W*(1-T)]	%Δ in AB	AC-Z	%Δ in AD	AE-Z	X-Z	4 Year Average of AD	4 Year Average of K
Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
Niagara Mohawk Power Corporation	NY	2010	739,966	1.0313	369,509	659,634	0.99937182	-0.0320	1.005597897	-0.0257	-0.0300	-0.0073	380,947
Niagara Mohawk Power Corporation	NY	2011	782,774	1.0579	369,738	658,435	0.998181466	-0.0597	1.004841086	-0.0530	-0.0584		
North Shore Gas Company	IL	2007	160,364		99,606	173,934					0.0000		
North Shore Gas Company	IL	2008	129,731	0.8090	99,865	171,113	0.983782553	0.1748	1.002356205	0.1934	0.1657		
North Shore Gas Company	IL	2009	120,556	0.9293	100,017	170,905	0.998786062	0.0695	0.998458165	0.0692	0.0661	0.0108	158,089
North Shore Gas Company	IL	2010	142,522	1.1822	103,167	183,478	1.073565937	-0.1086	0.999006386	-0.1832	-0.1267		
North Shore Gas Company	IL	2011	147,901	1.0377	100,335	173,407	0.945109821	-0.0926	1.002477004	-0.0353	-0.0791		
Northeast Ohio Natural Gas Corp.	OH	2007	7,082		25,752	28,950					0.0000		
Northeast Ohio Natural Gas Corp.	OH	2008	11,502	1.6241	30,180	31,847	1.100086768	-0.5240	1.583934532	-0.0402	-0.6121		
Northeast Ohio Natural Gas Corp.	OH	2009	12,595	1.0951	30,832	32,270	1.01329333	-0.0818	1.004146839	-0.0909	-0.0934	-0.1491	15,142
Northeast Ohio Natural Gas Corp.	OH	2010	13,696	1.0874	31,716	32,886	1.019071187	-0.0683	1.067023221	-0.0203	-0.0824		
Northeast Ohio Natural Gas Corp.	OH	2011	12,780	0.9332	32,234	33,237	1.010672255	0.0775	0.972463676	0.0393	0.0693		
Northern Illinois Gas Company	IL	2007	1,439,094		1,427,823	2,481,608					0.0000		
Northern Illinois Gas Company	IL	2008	1,481,551	1.0295	1,433,959	2,480,193	0.999429898	-0.0301	1.004960439	-0.0245	-0.0355		
Northern Illinois Gas Company	IL	2009	1,505,320	1.0160	1,428,709	2,472,322	0.996826529	-0.0192	0.999670568	-0.0164	-0.0165	-0.0189	2,177,016
Northern Illinois Gas Company	IL	2010	1,553,142	1.0318	1,429,276	2,466,562	0.99767013	-0.0341	1.00197494	-0.0298	-0.0336		
Northern Illinois Gas Company	IL	2011	1,541,189	0.9923	1,428,802	2,467,098	1.000217422	0.0079	1.003614582	0.0113	0.0091		
NSTAR Gas Company	MA	2007	295,692		129,631	71,838					0.0000		
NSTAR Gas Company	MA	2008	303,603	1.0268	131,310	72,728	1.012377725	-0.0144	1.004013448	-0.0227	-0.0136		
NSTAR Gas Company	MA	2009	327,393	1.0784	131,478	72,853	1.001729878	-0.0766	1.024218663	-0.0541	-0.0766	-0.0373	266,428
NSTAR Gas Company	MA	2010	334,790	1.0226	131,940	73,050	1.002706086	-0.0199	1.005946177	-0.0166	-0.0224		
NSTAR Gas Company	MA	2011	349,544	1.0441	132,486	73,474	1.005798597	-0.0383	1.007237843	-0.0368	-0.0402		
Ohio Gas Company	OH	2007	24,429		47,892	23,306					0.0000		
Ohio Gas Company	OH	2008	24,408	0.9991	48,060	23,363	1.002462258	0.0033	1.001185728	0.0021	0.0050		
Ohio Gas Company	OH	2009	23,427	0.9598	48,165	23,403	1.001691459	0.0419	0.99952627	0.0397	0.0418	-0.0194	46,595
Ohio Gas Company	OH	2010	23,320	0.9954	48,354	23,512	1.004650938	0.0092	1.001723469	0.0063	0.0194		
Ohio Gas Company	OH	2011	27,247	1.1684	49,921	24,368	1.036410177	-0.1320	1.011312315	-0.1571	-0.0993		
Oklahoma Natural Gas Company	OK	2007	502,323		732,894	722,454					0.0000		
Oklahoma Natural Gas Company	OK	2008	563,012	1.1208	735,162	690,238	0.955406781	-0.1654	1.004144815	-0.1167	-0.2579		
Oklahoma Natural Gas Company	OK	2009	614,309	1.0911	738,479	731,928	1.060399157	-0.0307	1.001463224	-0.0896	0.0943	-0.0858	846,453
Oklahoma Natural Gas Company	OK	2010	673,641	1.0966	749,943	711,341	0.971873799	-0.1247	0.990193052	-0.1064	-0.2037		
Oklahoma Natural Gas Company	OK	2011	692,934	1.0286	754,521	715,858	1.006349572	-0.0223	1.010663274	-0.0180	-0.0237		
Pacific Gas and Electric Company	CA	2007	2,742,662		1,995,274	7,579,685					0.0000		
Pacific Gas and Electric Company	CA	2008	2,876,652	1.0489	2,004,627	7,632,717	1.006996627	-0.0419	1.011950038	-0.0369	-0.0410		
Pacific Gas and Electric Company	CA	2009	2,959,079	1.0287	2,009,940	7,663,780	1.004069762	-0.0246	0.989219189	-0.0394	-0.0240	-0.0076	4,329,760
Pacific Gas and Electric Company	CA	2010	3,010,059	1.0172	2,013,108	7,702,686	1.005076506	-0.0122	0.999156528	-0.0181	-0.0106		
Pacific Gas and Electric Company	CA	2011	2,875,159	0.9552	2,017,855	7,729,862	1.003528191	0.0483	1.009535908	0.0544	0.0480		
PECO Energy Company	PA	2007	911,641		280,888	168,924					0.0000		
PECO Energy Company	PA	2008	829,321	0.9097	282,273	169,762	1.00496292	0.0953	1.004227061	0.0945	0.0980		
PECO Energy Company	PA	2009	1,143,880	1.3793	282,777	170,049	1.001693884	-0.3776	1.005390345	-0.3739	-0.3784	-0.0851	487,750
PECO Energy Company	PA	2010	1,160,383	1.0144	283,407	170,421	1.002184811	-0.0122	1.003664134	-0.0108	-0.0137		
PECO Energy Company	PA	2011	1,214,970	1.0470	283,667	170,639	1.001280704	-0.0458	1.011868548	-0.0352	-0.0460		
Peoples Gas Light and Coke Company	IL	2007	955,177		187,706	2,325,677					0.0000		
Peoples Gas Light and Coke Company	IL	2008	882,234	0.9236	187,118	2,286,898	0.98332547	0.0597	0.999508543	0.0759	0.0726		
Peoples Gas Light and Coke Company	IL	2009	845,291	0.9581	188,077	2,274,401	0.994535699	0.0364	0.990755336	0.0326	0.0419	-0.0367	824,653
Peoples Gas Light and Coke Company	IL	2010	994,123	1.1761	192,255	2,388,147	1.050011246	-0.1261	0.996410434	-0.1797	-0.1254		
Peoples Gas Light and Coke Company	IL	2011	1,091,048	1.0975	190,558	2,342,347	0.980822131	-0.1167	1.010281339	-0.0872	-0.1021		
Peoples Gas System	FL	2007	428,667		448,910	359,860					0.0000		
Peoples Gas System	FL	2008	453,897	1.0589	458,411	381,666	1.060596653	0.0017	1.001473278	-0.0574	0.1391		
Peoples Gas System	FL	2009	451,790	0.9954	464,500	385,075	1.008933098	0.0136	0.997177139	0.0018	0.0108	0.0020	336,021
Peoples Gas System	FL	2010	476,334	1.0543	475,871	403,949	1.049013692	-0.0053	1.005359467	-0.0490	0.0689		
Peoples Gas System	FL	2011	483,819	1.0157	486,234	409,423	1.013550003	-0.0022	1.008503837	-0.0072	-0.0078		
Philadelphia Gas Works Co.	PA	2007	530,346		127,027	113,836					0.0000		
Philadelphia Gas Works Co.	PA	2008	567,994	1.0710	127,069	113,650	0.998362308	-0.0726	1.000012042	-0.0710	-0.0727		
Philadelphia Gas Works Co.	PA	2009	596,344	1.0499	127,279	113,734	1.000743451	-0.0492	0.995434065	-0.0545	-0.0491	-0.0594	497,593
Philadelphia Gas Works Co.	PA	2010	643,490	1.0791	127,283	113,836	1.000891277	-0.0782	1.002554538	-0.0765	-0.0781		
Philadelphia Gas Works Co.	PA	2011	667,162	1.0368	127,283	113,747	0.999215865	-0.0376	1.003304193	-0.0335	-0.0376		
Pike County Light and Power Company	PA	2007	432		840	273					0.0000		
Pike County Light and Power Company	PA	2008	213	0.4921	840	273	1	0.5079	1.017064846	0.5249	0.5079		
Pike County Light and Power Company	PA	2009	682	3.2066	798	316	1.156681161	-2.0499	1	-2.2066	-2.3769	-0.5795	1,194
Pike County Light and Power Company	PA	2010	1,286	1.8850	780	287	0.909708014	-0.9753	1.005033557	-0.8799	-0.8714		
Pike County Light and Power Company	PA	2011	1,047	0.8141	778	291	1.013490325	0.1994	0.994991653	0.1809	0.1785		
Pike Natural Gas Co	OH	2007	2,308		11,808	6,659					0.0000		
Pike Natural Gas Co	OH	2008	2,392	1.0365	11,833	6,673	1.002052846	-0.0345	0.993426573	-0.0431	-0.0354		
Pike Natural Gas Co	OH	2009	2,297	0.9603	11,888	6,723	1.007619885	0.0473	1.003238068	0.0429	0.0404	-0.0133	7,120
Pike Natural Gas Co	OH	2010	2,331	1.0146	11,922	6,755	1.004656236	-0.0100	1.001964637	-0.0127	-0.0142		
Pike Natural Gas Co	OH	2011	2,473	1.0608	11,968	6,788	1.004922654	-0.0558	0.995658263	-0.0651	-0.0593		

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Formula:			D*(1-J)+(G*J)	%Δ in Y	K/S	(AA*T)+[W*(1-T)]	%Δ in AB	AC-Z	%Δ in AD	AE-Z	X-Z	4 Year Average of AD	4 Year Average of K
Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
Pivotal Utility Holdings, Inc.	MD	2007	4,341		3,695	2,081					0.0000		
Pivotal Utility Holdings, Inc.	MD	2008	4,823	1.1109	3,989	2,538	1.219230155	0.1084	1.003167723	-0.1077	-0.1928		
Pivotal Utility Holdings, Inc.	MD	2009	4,917	1.0196	4,031	2,579	1.016112544	-0.0035	1.013461858	-0.0062	-0.0169	-0.0012	6,085
Pivotal Utility Holdings, Inc.	MD	2010	5,083	1.0336	4,039	2,557	0.99147147	-0.0421	0.992948508	-0.0407	0.0114		
Pivotal Utility Holdings, Inc.	MD	2011	5,484	1.0789	4,091	2,586	1.011477167	-0.0674	1.018662263	-0.0602	-0.0496		
Pivotal Utility Holdings, Inc.	NJ	2007	394,194		128,459	80,815					0.0000		
Pivotal Utility Holdings, Inc.	NJ	2008	386,087	0.9794	128,669	81,454	1.007903729	0.0285	1.004914086	0.0255	0.0101		
Pivotal Utility Holdings, Inc.	NJ	2009	391,769	1.0147	129,929	82,560	1.01357265	-0.0011	1.001018304	-0.0137	0.0047	-0.0364	274,046
Pivotal Utility Holdings, Inc.	NJ	2010	435,956	1.1128	131,369	83,482	1.011177801	-0.1016	1.003677533	-0.1091	-0.1072		
Pivotal Utility Holdings, Inc.	NJ	2011	473,356	1.0858	132,339	84,674	1.014274201	-0.0715	1.004838016	-0.0810	-0.0726		
Public Service Company of Colorado	CO	2007	862,509		976,312	1,049,491					0.0000		
Public Service Company of Colorado	CO	2008	881,547	1.0221	986,113	1,135,270	1.081734418	0.0597	1.011427871	-0.0106	0.2426		
Public Service Company of Colorado	CO	2009	947,907	1.0753	987,285	1,344,151	1.183991985	0.1087	1.011122879	-0.0642	-0.0778	0.0032	1,296,424
Public Service Company of Colorado	CO	2010	904,037	0.9537	992,229	1,213,345	0.902685356	-0.0510	1.00670081	0.0530	-0.1009		
Public Service Company of Colorado	CO	2011	937,920	1.0375	1,058,007	1,132,123	0.93305909	-0.1044	1.006364404	-0.0311	-0.0525		
Public Service Company of North Carolina, Incorporated	NC	2007	739,755		431,092	430,847					0.0000		
Public Service Company of North Carolina, Incorporated	NC	2008	790,303	1.0683	441,091	439,442	1.019948753	-0.0484	1.031593184	-0.0367	-0.0531		
Public Service Company of North Carolina, Incorporated	NC	2009	831,894	1.0526	445,313	442,234	1.006354411	-0.0463	1.016118864	-0.0365	-0.0510	-0.0328	469,272
Public Service Company of North Carolina, Incorporated	NC	2010	857,317	1.0306	450,325	445,001	1.006256241	-0.0243	1.014617987	-0.0159	-0.0317		
Public Service Company of North Carolina, Incorporated	NC	2011	897,991	1.0474	457,130	460,646	1.035157672	-0.0123	1.016239777	-0.0312	0.0176		
Public Service Electric and Gas Company	NJ	2007	1,695,601		742,259	585,094					0.0000		
Public Service Electric and Gas Company	NJ	2008	1,750,687	1.0325	742,007	583,880	0.997924274	-0.0346	1.005658612	-0.0268	-0.0383		
Public Service Electric and Gas Company	NJ	2009	1,776,167	1.0146	740,999	582,907	0.998334383	-0.0162	1.018385457	0.0038	-0.0180	-0.0578	1,768,448
Public Service Electric and Gas Company	NJ	2010	1,921,102	1.0816	742,322	582,402	0.999133828	-0.0825	1.002423823	-0.0792	-0.0860		
Public Service Electric and Gas Company	NJ	2011	2,111,064	1.0989	743,582	582,986	1.001002653	-0.0979	1.000558381	-0.0983	-0.0995		
Puget Sound Energy, Inc.	WA	2007	1,265,764		494,243	399,989					0.0000		
Puget Sound Energy, Inc.	WA	2008	1,336,439	1.0558	500,983	405,965	1.014942589	-0.0409	1.021943244	-0.0339	0.0030		
Puget Sound Energy, Inc.	WA	2009	1,395,836	1.0444	504,220	406,440	1.001170091	-0.0433	1.01178301	-0.0327	-0.1200	-0.0322	747,973
Puget Sound Energy, Inc.	WA	2010	1,394,829	0.9993	505,395	407,579	1.00280236	0.0035	1.005719751	0.0064	0.0043		
Puget Sound Energy, Inc.	WA	2011	1,465,645	1.0508	506,782	408,632	1.002583204	-0.0482	1.007858222	-0.0429	-0.0490		
Rochester Gas and Electric Corporation	NY	2007	286,033		200,388	245,452					0.0000		
Rochester Gas and Electric Corporation	NY	2008	295,948	1.0347	201,228	245,474	1.00008784	-0.0346	1.004408526	-0.0303	-0.0357		
Rochester Gas and Electric Corporation	NY	2009	278,166	0.9399	202,194	245,973	1.002033837	0.0621	1.004540295	0.0646	0.0603	-0.0045	300,309
Rochester Gas and Electric Corporation	NY	2010	283,614	1.0196	203,058	246,226	1.001026201	-0.0186	1.007220941	-0.0124	-0.0197		
Rochester Gas and Electric Corporation	NY	2011	291,338	1.0272	203,511	246,311	1.000344778	-0.0269	1.005801719	-0.0214	-0.0275		
San Diego Gas & Electric Co.	CA	2007	430,366		360,337	517,821					0.0000		
San Diego Gas & Electric Co.	CA	2008	425,676	0.9891	359,413	510,009	0.984913735	-0.0042	1.00458308	0.0155	-0.0007		
San Diego Gas & Electric Co.	CA	2009	446,801	1.0496	360,757	510,969	1.001881895	-0.0477	1.004278451	-0.0453	-0.0489	-0.0328	845,185
San Diego Gas & Electric Co.	CA	2010	497,905	1.1144	362,689	513,137	1.004243215	-0.1101	1.005771303	-0.1086	-0.1118		
San Diego Gas & Electric Co.	CA	2011	483,510	0.9711	363,739	514,069	1.001815817	0.0307	1.00569924	0.0346	0.0298		
South Carolina Electric & Gas Co.	SC	2007	309,552		357,230	293,490					0.0000		
South Carolina Electric & Gas Co.	SC	2008	329,666	1.0650	367,686	302,542	1.030839564	-0.0341	1.016486327	-0.0485	-0.0266		
South Carolina Electric & Gas Co.	SC	2009	361,093	1.0953	373,733	305,268	1.009010375	-0.0863	1.011601867	-0.0837	-0.0914	-0.0467	309,244
South Carolina Electric & Gas Co.	SC	2010	391,289	1.0836	375,437	306,887	1.005304282	-0.0783	1.010808895	-0.0728	-0.0870		
South Carolina Electric & Gas Co.	SC	2011	389,226	0.9947	378,907	308,980	1.006819534	0.0121	1.010886275	0.0162	0.0097		
South Jersey Gas Company	NJ	2007	635,142		244,744	252,700					0.0000		
South Jersey Gas Company	NJ	2008	646,968	1.0186	246,633	254,079	1.005458612	-0.0132	0.925307593	-0.0933	-0.0161		
South Jersey Gas Company	NJ	2009	687,447	1.0626	250,875	257,738	1.01439995	-0.0482	1.012273614	-0.0503	-0.0525	-0.0411	343,104
South Jersey Gas Company	NJ	2010	751,043	1.0925	254,512	282,424	1.095782008	0.0033	1.011204744	-0.0813	0.1246		
South Jersey Gas Company	NJ	2011	839,454	1.1177	258,006	285,634	1.011364299	-0.1064	1.010924117	-0.1068	-0.1088		
Southern California Gas Company	CA	2007	3,120,583		2,163,746	7,624,750					0.0000		
Southern California Gas Company	CA	2008	3,229,524	1.0349	2,164,249	7,409,281	0.971740787	-0.0632	1.003930411	-0.0310	-0.0666		
Southern California Gas Company	CA	2009	3,433,472	1.0632	2,168,491	7,400,348	0.998794368	-0.0644	1.005040238	-0.0581	-0.0638	-0.0640	5,507,156
Southern California Gas Company	CA	2010	3,666,898	1.0680	2,208,719	7,415,187	1.00200522	-0.0660	1.00398711	-0.0640	-0.0764		
Southern California Gas Company	CA	2011	3,876,393	1.0571	2,209,685	7,375,859	0.994696314	-0.0624	1.005896825	-0.0512	-0.0648		
Southern Connecticut Gas Company	CT	2007	407,182		94,945	58,913					0.0000		
Southern Connecticut Gas Company	CT	2008	416,780	1.0236	95,155	59,056	1.002435555	-0.0211	1.002594695	-0.0210	-0.0248		
Southern Connecticut Gas Company	CT	2009	377,441	0.9056	95,281	59,078	1.000373939	0.0948	1.003867687	0.0983	0.0923	0.0425	175,885
Southern Connecticut Gas Company	CT	2010	345,426	0.9152	95,449	59,236	1.002665433	0.0875	0.998861806	0.0837	0.0823		
Southern Connecticut Gas Company	CT	2011	343,712	0.9950	95,785	59,474	1.004021517	0.0090	1.009970544	0.0149	0.0046		
Southern Indiana Gas and Electric Company, Inc.	IN	2007	78,397		135,006	143,492					0.0000		
Southern Indiana Gas and Electric Company, Inc.	IN	2008	81,045	1.0338	134,544	142,916	0.995985648	-0.0378	0.995088294	-0.0387	-0.0361		
Southern Indiana Gas and Electric Company, Inc.	IN	2009	83,783	1.0338	135,103	143,852	1.006551681	-0.0272	0.99418715	-0.0396	-0.0227	-0.0386	110,116
Southern Indiana Gas and Electric Company, Inc.	IN	2010	85,762	1.0236	135,564	145,653	1.012514914	-0.0111	1.000318257	-0.0233	0.0033		
Southern Indiana Gas and Electric Company, Inc.	IN	2011	92,467	1.0782	135,661	145,655	1.000017665	-0.0782	0.998681926	-0.0795	-0.0795		
St. Joe Natural Gas Co, Inc.	FL	2007	1,512		6,173	3,966					0.0000		
St. Joe Natural Gas Co, Inc.	FL	2008	2,002	1.3240	6,257	4,011	1.011585863	-0.3124	0.987092611	-0.3369	-0.3144		

Schedule 2: Natural Gas LDC Data Base

A	B	C	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Formula:			D*(1-J)+(G*J)	%Δ in Y	K/S	(AA*T)+[W*(1-T)]	%Δ in AB	AC-Z	%Δ in AD	AE-Z	X-Z	4 Year Average of AD	4 Year Average of K
Utility	State of Operation	Year	Cost Change	% Cost Change by Year	Customers/Density Index	Output Measure	% Output Change by Year	TFP Composite Measure	% Change in Customers	TFP Customers	TFP Capacity	Average TFP (2008-2011)	Average Customers (2008-2011)
St. Joe Natural Gas Co, Inc.	FL	2009	2,147	1.0721	6,299	4,017	1.001412244	-0.0707	0.967963387	-0.1041	-0.0638	-0.0768	2,975
St. Joe Natural Gas Co, Inc.	FL	2010	2,187	1.0187	6,971	4,109	1.022843261	0.0041	1	-0.0187	0.1118		
St. Joe Natural Gas Co, Inc.	FL	2011	2,072	0.9477	7,055	4,189	1.019467335	0.0718	0.985140155	0.0375	0.0546		
St. Lawrence Gas Company, Inc.	NY	2007	17,729		15,747	20,802					0.0000	-0.0267	15,446
St. Lawrence Gas Company, Inc.	NY	2008	17,157	0.9677	15,873	20,940	1.006612084	0.0389	0.997070122	0.0293	0.0327		
St. Lawrence Gas Company, Inc.	NY	2009	16,731	0.9752	15,873	20,940	1	0.0248	1.009337861	0.0341	0.0248		
St. Lawrence Gas Company, Inc.	NY	2010	19,406	1.1598	15,954	21,145	1.009785841	-0.1501	1.00323478	-0.1566	-0.1465		
St. Lawrence Gas Company, Inc.	NY	2011	19,822	1.0215	16,009	21,163	1.00086854	-0.0206	0.999935513	-0.0215	-0.0214		
Superior Water, Light and Power Company	WI	2007	7,505		12,178	8,908					0.0000	-0.0074	12,266
Superior Water, Light and Power Company	WI	2008	7,738	1.0310	12,220	8,925	1.001925416	-0.0291	1.004295746	-0.0267	-0.0457		
Superior Water, Light and Power Company	WI	2009	7,464	0.9647	12,220	8,925	1	0.0353	1.008472485	0.0438	0.0353		
Superior Water, Light and Power Company	WI	2010	7,146	0.9573	12,262	8,963	1.004258587	0.0469	1.005138662	0.0478	0.0429		
Superior Water, Light and Power Company	WI	2011	7,828	1.0956	12,388	9,077	1.012740182	-0.0828	1	-0.0956	-0.0947		
Texas Gas Service Company	TX	2007	294,457		393,427	402,065					0.0000	-0.0628	607,380
Texas Gas Service Company	TX	2008	310,599	1.0548	397,459	404,328	1.005630724	-0.0492	1.002923877	-0.0519	-0.0579		
Texas Gas Service Company	TX	2009	308,721	0.9940	405,101	380,381	0.940771382	-0.0532	1.025809099	0.0319	-0.2048		
Texas Gas Service Company	TX	2010	308,846	1.0004	409,975	360,788	0.948492034	-0.0519	1.014911012	0.0145	-0.2068		
Texas Gas Service Company	TX	2011	339,655	1.0998	411,429	361,857	1.002963937	-0.0968	1.011859111	-0.0879	-0.0999		
UGI Central Penn Gas, Inc.	PA	2007	127,495		158,824	128,882					0.0000	-0.0985	76,031
UGI Central Penn Gas, Inc.	PA	2008	138,302	1.0848	159,360	122,954	0.954007305	-0.1308	0.991949493	-0.0928	-0.2120		
UGI Central Penn Gas, Inc.	PA	2009	177,282	1.2818	159,781	123,304	1.002844965	-0.2790	0.990655671	-0.2912	-0.2813		
UGI Central Penn Gas, Inc.	PA	2010	174,709	0.9855	159,613	120,576	0.977875231	-0.0076	0.99901058	0.0135	-0.0474		
UGI Central Penn Gas, Inc.	PA	2011	171,022	0.9789	160,113	120,851	1.002284654	0.0234	1.004635071	0.0257	0.0229		
UGI Utilities, Inc.	PA	2007	506,686		220,880	165,682					0.0000	-0.0178	339,021
UGI Utilities, Inc.	PA	2008	511,677	1.0098	224,181	168,642	1.017865379	0.0080	1.021362283	0.0115	0.0078		
UGI Utilities, Inc.	PA	2009	527,179	1.0303	228,250	171,299	1.015754082	-0.0145	1.016181387	-0.0141	-0.0259		
UGI Utilities, Inc.	PA	2010	556,036	1.0547	228,865	171,967	1.003900605	-0.0508	1.0142028	-0.0405	-0.0559		
UGI Utilities, Inc.	PA	2011	568,609	1.0226	230,885	173,477	1.008784062	-0.0138	1.031624947	0.0090	-0.0207		
Valley Energy Inc.	NY	2007	969		1,279	524					0.0000	-0.1548	1,656
Valley Energy Inc.	NY	2008	1,695	1.7497	1,280	525	1.001890231	-0.7478	1.019783025	-0.7299	-0.7496		
Valley Energy Inc.	NY	2009	1,638	0.9665	1,311	552	1.051682275	0.0852	1.029411765	0.0629	0.0364		
Valley Energy Inc.	NY	2010	1,556	0.9499	1,339	562	1.018754511	0.0688	1.02006079	0.0701	0.0987		
Valley Energy Inc.	NY	2011	1,614	1.0377	1,347	569	1.012364787	-0.0253	1.014898689	-0.0228	-0.0362		
Valley Energy Inc.	PA	2007	7,266		6,108	4,142					0.0000	-0.0357	5,772
Valley Energy Inc.	PA	2008	8,423	1.1591	6,111	4,151	1.002289246	-0.1568	1.018008085	-0.1411	-0.1582		
Valley Energy Inc.	PA	2009	7,661	0.9096	6,142	4,175	1.005789861	0.0962	1.03267148	0.1231	0.0905		
Valley Energy Inc.	PA	2010	8,404	1.0969	6,239	4,221	1.010989804	-0.0859	1.025520014	-0.0714	-0.0869		
Valley Energy Inc.	PA	2011	8,458	1.0065	6,341	4,264	1.010151459	0.0037	1.015510482	0.0090	0.0012		
Vectren Energy Delivery of Ohio, Inc.	OH	2007	296,056		231,043	352,466					0.0000	-0.0273	312,132
Vectren Energy Delivery of Ohio, Inc.	OH	2008	307,278	1.0379	231,672	352,706	1.000680953	-0.0372	0.997189784	-0.0407	-0.0377		
Vectren Energy Delivery of Ohio, Inc.	OH	2009	305,252	0.9934	232,305	350,167	0.992802089	-0.0006	0.991171113	-0.0022	-0.0032		
Vectren Energy Delivery of Ohio, Inc.	OH	2010	317,064	1.0387	232,798	349,861	0.999126863	-0.0396	0.994816214	-0.0439	-0.0387		
Vectren Energy Delivery of Ohio, Inc.	OH	2011	326,247	1.0290	231,954	348,861	0.997142002	-0.0318	0.999044097	-0.0299	-0.0285		
Vermont Gas Systems, Inc.	VT	2007	66,597		29,269	30,558					0.0000	-0.0402	42,666
Vermont Gas Systems, Inc.	VT	2008	72,179	1.0838	30,067	31,110	1.018056068	-0.0658	1.026190476	-0.0576	-0.0813		
Vermont Gas Systems, Inc.	VT	2009	76,472	1.0595	30,906	31,764	1.021025317	-0.0385	1.034656246	-0.0248	-0.0525		
Vermont Gas Systems, Inc.	VT	2010	78,645	1.0284	31,385	32,286	1.016422384	-0.0120	1.02027665	-0.0081	-0.0099		
Vermont Gas Systems, Inc.	VT	2011	82,661	1.0511	31,761	32,501	1.006663126	-0.0444	1.02103047	-0.0300	-0.0534		
Virginia Natural Gas, Inc.	VA	2007	291,204		225,248	286,147					0.0000	-0.1875	274,377
Virginia Natural Gas, Inc.	VA	2008	346,509	1.1899	224,702	285,216	0.996748231	-0.1932	1.007827731	-0.1821	-0.1873		
Virginia Natural Gas, Inc.	VA	2009	516,193	1.4897	226,759	286,266	1.003678968	-0.4860	1.004911443	-0.4848	-0.4896		
Virginia Natural Gas, Inc.	VA	2010	553,588	1.0724	229,859	310,912	1.086096449	0.0137	1.008960915	-0.0635	0.1110		
Virginia Natural Gas, Inc.	VA	2011	602,521	1.0884	230,423	312,145	1.003965328	-0.0844	1.010869091	-0.0775	-0.0854		
Wisconsin Gas LLC	WI	2007	425,961		446,842	520,200					0.0000	-0.0150	595,851
Wisconsin Gas LLC	WI	2008	450,389	1.0573	449,865	527,647	1.014316649	-0.0430	1.006174078	-0.0512	-0.0363		
Wisconsin Gas LLC	WI	2009	442,875	0.9833	452,301	527,064	0.998894429	0.0156	1.004737303	0.0214	0.0095		
Wisconsin Gas LLC	WI	2010	432,331	0.9762	453,834	525,271	0.996597351	0.0204	1.004412294	0.0282	0.0156		
Wisconsin Gas LLC	WI	2011	459,883	1.0637	460,414	530,989	1.010886016	-0.0528	1.003602723	-0.0601	-0.0569		
Wisconsin Power and Light Company	WI	2007	103,659		162,721	120,060					0.0000	-0.1269	177,965
Wisconsin Power and Light Company	WI	2008	155,109	1.4963	164,316	120,957	1.007477024	-0.4889	1.010271485	-0.4861	-0.4918		
Wisconsin Power and Light Company	WI	2009	153,322	0.9885	165,660	121,749	1.006545059	0.0181	1	0.0115	0.0153		
Wisconsin Power and Light Company	WI	2010	161,548	1.0537	167,523	122,532	1.006429334	-0.0472	1.009408488	-0.0442	-0.0558		
Wisconsin Power and Light Company	WI	2011	161,653	1.0006	169,982	123,908	1.011232081	0.0106	1.010885475	0.0102	0.0055		
Wyoming Gas Company	WY	2007	3,275		11,338	8,189					0.0000	-0.0986	6,849
Wyoming Gas Company	WY	2008	3,810	1.1634	11,590	8,436	1.030205372	-0.1332	1.006384558	-0.1570	-0.1572		
Wyoming Gas Company	WY	2009	4,220	1.1075	11,506	8,491	1.006477613	-0.1011	1.011802892	-0.0957	-0.1696		
Wyoming Gas Company	WY	2010	4,896	1.1603	11,800	8,669	1.020951177	-0.1393	1.002770487	-0.1575	-0.1351		

Schedule 2: Natural Gas LDC Data Base

A	B	C	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
Formula:			**D*(1-J)+(G*J)**	**%Δ in Y**	**K/S**	**(AA*T)+[W*(1-T)]**	**%Δ in AB**	**AC-Z**	**%Δ in AD**	**AE-Z**	**X-Z**	**4 Year Average of AD**	**4 Year Average of K**
Utility	**State of Operation**	**Year**	**Cost Change**	**% Cost Change by Year**	**Customers/Density Index**	**Output Measure**	**% Output Change by Year**	**TFP Composite Measure**	**% Change in Customers**	**TFP Customers**	**TFP Capacity**	**Average TFP (2008-2011)**	**Average Customers (2008-2011)**
Wyoming Gas Company	**WY**	**2011**	5,159	1.0537	12,052	8,954	1.032902322	-0.0208	1.000581649	-0.0531	-0.0530		
Yankee Gas Services Company	**CT**	**2007**	480,322		133,003	70,815					0.0000		
Yankee Gas Services Company	**CT**	**2008**	504,969	1.0513	133,586	71,037	1.003136008	-0.0482	1.010318482	-0.0410	-0.0499		
Yankee Gas Services Company	**CT**	**2009**	486,960	0.9643	135,130	71,701	1.009353908	0.0450	1.007825811	0.0435	0.0431	-0.0463	206,228
Yankee Gas Services Company	**CT**	**2010**	556,424	1.1426	136,034	73,485	1.024869279	-0.1178	0.997326074	-0.1453	-0.1090		
Yankee Gas Services Company	**CT**	**2011**	601,367	1.0808	136,733	74,689	1.016387551	-0.0644	1.009068125	-0.0717	-0.0594		

Appendix D3

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Russell Feingold

Mr. Feingold is an experienced, officer-level management consultant with a broad range of project and managerial experience involving gas and electric utilities. Specializing in the energy and utilities industries, he has advised energy clients pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, innovative ratemaking concepts, gas supply planning and procurement issues, strategic business planning, merger and acquisition analysis, regulatory due diligence, corporate restructuring, new product and service development, load research and demand forecasting studies, and market planning. He has prepared and presented expert testimony submitted to the FERC, and several state and provincial regulatory commissions dealing with the costing, pricing, and marketing of gas and electric utility services.

PROJECT EXPERIENCE

Utility Ratemaking and Regulatory Policy Analysis

Mr. Feingold is a nationally recognized expert in all elements of utility costing, pricing and regulatory requirements. He has participated in numerous projects for gas and electric utilities and has extensive experience in a broad range of utility ratemaking issues, including:

- Fully allocated and marginal cost studies;
- Rate design, strategic and market-based pricing;
- Service and rate unbundling;
- Revenue sharing;
- Revenue decoupling, weather normalization and other automatic adjustment rate mechanisms;
- Infrastructure cost recovery mechanisms;
- Incentive ratemaking and Performance-Based Ratemaking (PBR); and
- End-user bypass and energy regulation analysis.

He has worked closely with a number of gas and electric utilities to develop the conceptual underpinnings, regulatory evidence and related filings, and has provided expert testimonial support for the implementation of various automatic adjustment rate mechanisms to address variability of energy sales (revenue decoupling) and the timely recovery of costs associated with infrastructure replacement, uncollectible accounts expense and energy efficiency and conservation programs for utility end-use customers.

He has assisted clients in the evaluation and development of PBR approaches to replace traditional cost-based regulation. In particular, he has worked with:

- A combination utility to develop gas and electric price cap mechanisms for its distribution businesses;
- A Canadian gas utility to provide strategic and issue-oriented support for development and implementation of a "second generation" PBR plan;

VICE PRESIDENT, RATES & REGULATORY PRACTICE LEAD

Specialization:
Utility Ratemaking and Regulatory Policy Analysis, Utility Costing and Pricing, Rate Case Management, Competitive Market Analysis, Strategic Business Planning, Corporate Restructuring, New Product and Service Development, Energy Litigation Support, Expert Testimony

Education
- Polytechnic Institute of New York, MS Financial Management, 1977.
- Washington University, St. Louis, BS Electrical Engineering, 1973.

Professional Associations
- American Gas Association, Financial Associate Member
- Member, Rate Committee of the American Gas Association
- Member, Energy Bar Association
- Member, Energy Bar Association Electricity and Natural Gas Regulation Committees
- Member, Institute of Electrical and Electronic Engineers

Year Career Started
1973

Year Started with B&V
2007

- An Eastern gas utility to evaluate and develop a performance-based Purchased Gas Adjustment (PGA) mechanism;
- A Midwestern gas utility to develop performance-based gas procurement measures for use in conjunction with the filing of performance-based PGA mechanisms before state regulators; and
- A Midwestern electric utility to evaluate and develop a price cap mechanism to be applied to each of its classes of service.

For a Northeastern gas utility, Mr. Feingold directed an effort to develop the activity-based cost support for a wide range of unbundled services in conjunction with establishing a residential pilot program permitting all customers the opportunity to purchase all or any part of their energy requirements on a competitive basis from third-party suppliers.

Mr. Feingold was responsible for conducting an in-depth analysis of the current gas rates and services for a Midwestern gas utility. He developed an appropriate pricing structure for the utility's unbundled gas transportation and storage services and assisted in establishing a longer-range pricing strategy for all utility services with support provided through the presentation of expert testimony. This assignment is typical of Mr. Feingold's work in the utility rate design and analysis area.

Interstate Natural Gas Pipeline Ratemaking and Regulation

Mr. Feingold has worked on numerous ratemaking and regulatory projects on behalf of major natural gas shippers involving interstate natural gas pipeline companies regulated by the Federal Energy Regulatory Commission in the U.S. and the National Energy Board in Canada. These projects have addressed a wide variety of issues, including:

- Revenue requirements;
- Cost allocation methods
- Rate design and competitive pricing;
- Service and rate unbundling;
- Sales forecasting analyses;
- Revenue sharing methods;
- Fuel cost recovery and fuel tracker mechanisms; and
- Expert testimony and energy litigation support.

Competitive Market Assessment

In conjunction with the deregulation of the gas and electric utility industries, Mr. Feingold has assisted utilities with the evaluation and development of new energy-related products and services. These assignments typically include an assessment of competitors and the strategic opportunities and threats posed by future market conditions, an assessment of customer needs, development of high-level product and service strategies, development of prototype products and services, an evaluation of their expected financial performance, preparation of market rollout strategies and a specification of the corporate infrastructure requirements associated with their market rollout.

On behalf of an unregulated energy marketing affiliate, Mr. Feingold directed a project to assess the claims made by the U.S. Department of Justice that the marketing affiliate violated antitrust laws. Specifically, the claims focused on the impact that the company's formation had on competition related to secondary capacity rights on interstate natural gas pipelines and whether there was any attempt to monopolize that capacity.

Within the broader context of the North American gas commodity and pipeline transportation markets, a detailed market power assessment was conducted that evaluated the pipeline capacity held by the marketer relative to the capacity held by other competing shippers on the pipeline. Based on his analysis, it was concluded that the energy marketer was not in a position to exercise any level of market power under any economic or legal standard.

On behalf of NSTAR Companies, Mr. Feingold directed a project to conduct a competitive assessment of various unbundled services, including customer billing, call center operations, meter services, meter reading, street lighting, and distribution service (both gas and electric functions). The work consisted of the following activities:

- Identify the services provided by gas and electric distribution companies;
- Identify the actual costs of providing these services;
- Benchmark the utility's performance against other companies;
- Identify current and future competitors for each service; and
- Formulate a business plan for each service.

Mr. Feingold has directed or participated in various projects related to market analysis and demand forecasting, as well as the functional area of marketing. As part of broader pricing-related projects, he has reviewed and assisted in the development of the marketing strategies, plans and programs of many local distribution companies. These projects have included market research and segmentation analysis, market forecasting, load research and customer focus group evaluations. Mr. Feingold's clients in this area have included numerous Midwestern and Northeastern gas and electric utilities.

For a Southern gas utility, Mr. Feingold performed a strategic and operational assessment of its marketing, pricing and gas supply operations, as well as emerging opportunities in the natural gas and electric power marketing industries.

Mr. Feingold participated in a project for a Midwestern gas utility to develop comprehensive integrated least-cost plans for filing before its state regulatory commission. This project dealt with all aspects of integrated resource planning, including gas supply-side planning and strategies, DSM program screening, development and implementation, evaluation of cost recovery mechanisms, supply- and demand-side integration activities, and regulatory presentation and acceptance. Other gas utilities for which similar services were provided include a Midwestern gas utility, a Southern gas utility and an Eastern gas utility.

Mergers, Acquisition, and Corporate Restructuring

Mr. Feingold served as the overall Project Officer for a long-term assignment with Detroit Edison Company, Michigan Consolidated Gas Company (MCN) and the Federal Trade Commission (FTC) in conjunction with Detroit Edison's acquisition of MCN. Specifically, he served as the Auditor of a 20-year Easement Agreement (for gas distribution assets) between MCN and Exelon Energy to implement a competitive remedy required by the FTC, as a pre-condition of the merger, pertaining to the supply of natural gas to any electric displacement loads in the merged utility service territories.

Mr. Feingold served as Project Manager in providing assistance to an Eastern utility holding corporation during its proposed acquisition of an Eastern gas and water utility. His responsibilities included the identification of the potential savings that would result from the acquisition, the development of an inter-jurisdictional gas cost allocation methodology and related assistance dealing with obtaining the necessary regulatory approval of the acquisition.

On behalf of Indiana Gas Company (Vectren Energy) and Citizens Gas & Coke Utility, he provided strategic and litigation support in conjunction with their formation of an unregulated gas merchant/marketing company (ProLiance Energy, LLC). His responsibilities included:

- Assessment of the strategic and economic benefits of the new company from the perspective of the LDCs' ratepayers;
- Evaluation of how formation of the proposed company was an appropriate response to the changes that have occurred within the natural gas industry; and
- Evaluation of a number of market power-related issues pertaining to the formation.

Mr. Feingold filed expert testimony before the state regulatory body concerning the results of his efforts.

On behalf of a Union Gas Limited (Westcoast Energy/Duke Energy), Mr. Feingold directed a project to organizationally separate the utility's Energy Solutions Business from its Gas Delivery Business. Specifically, the project team conducted the following tasks:

- Researched and established the client's business and cost separation principles;

- Developed computer modeling capabilities to conduct the underlying cost separation analysis;
- Conducted the cost separation study;
- Assisted in the restructuring of the client's shared corporate services;
- Assisted in the establishment of transfer pricing principles for use in setting prices of shared services between the two businesses;
- Advised the client's executive group on business separation strategies and issues; and
- Prepared and supported expert evidence before the client's regulatory body.

Mr. Feingold was responsible for an assignment with a major Midwestern gas utility to evaluate a potential acquisition of specific transmission assets, gas production contracts and related gathering facilities from another company. His responsibilities included conducting an economic and non-economic evaluation of the potential acquisition, assessing the impact of the acquisition from an operating, financial and regulatory perspective and identifying the key risks related to the acquisition.

On behalf of a Southern gas utility, Mr. Feingold participated in the restructuring of an existing corporate organization into gas distribution (intrastate) and gas pipeline (interstate) operating divisions. He assisted in the operational, regulatory, legal, financial, and accounting analyses that developed financial, gas supply and market forecasts necessary to determine the effects of the reorganization.

Gas Supply Planning and Procurement

Mr. Feingold has conducted numerous studies related to gas supply procurement and planning for local distribution companies and combination utilities. These studies have analyzed a wide range of issues, including the availability and cost of future supplies; evaluation of alternate gas supply and deliverability resources; gas supply planning, procurement and management processes of a utility; supply reliability and peak day/winter season capacity levels; and the appropriateness of a capacity reserve margin.

Additionally, he has been involved in gas supply modeling activities related to least-cost planning and the evaluation of transportation project alternatives. Mr. Feingold has provided these services to various local distribution companies, including three Midwestern gas utilities, a Western gas and electric utility, a Southern gas utility, a Midwestern gas and electric utility, an Eastern gas and electric utility and a Midwestern gas utility.

Mr. Feingold worked with numerous gas distribution utilities to analyze and support through expert testimony their design day demand and capacity requirements before utility regulators. These included South Jersey Gas

Company, Equitable Gas Company, Dominion Peoples and Dominion East Ohio and PG Energy.

On behalf of the Gas Research Institute (GRI), Mr. Feingold directed a comprehensive study to evaluate the future role of peak-shaving in gas utility operations. The objective of the study was to:

- Evaluate the role of peak-shaving supplies in relation to storage and deliverability within the larger context of the evolving demand profile in the natural gas industry;
- Determine peak-shaving costs;
- Summarize trends in utility decision practices that influence the value of peak-shaving supplies;
- Assess the opportunity to realize synergies with utility peak-shaving and new-end uses, such as power generation and transportation;
- Project future demand for peak-shaving supplies; and
- Isolate any issues or barriers to increasing the benefit of utilization of peak-shaving supplies and identify any R&D opportunities.

Mr. Feingold has also advised electric utility clients on the procurement of gas supply and interstate capacity resources for use in electric generation, including Nevada Power Company and an Eastern combination utility.

Operational and Transactional Reviews

On behalf of a Canadian gas utility, Mr. Feingold was responsible for establishing the original organizational framework and structure for the utility's rate and regulatory activities. He identified and specified database requirements; manpower and work experience requirements, established job descriptions, and delineated the appropriate manner in which the department's activities should interface with other corporate activities within the company.

On behalf of one of the largest integrated gas companies, Mr. Feingold directed a comprehensive review of inter-company transactions and relationships among its affiliate organizations. His responsibilities included examining the appropriateness of its affiliate transaction process and evaluating how reasonable the level of affiliate charges incurred were by each of the LDC affiliates and conducting a comparative assessment of its affiliate transactions through benchmarking against the transactions of similarly-situated gas utilities.

Mr. Feingold led a project team on an assignment for a major mid-Atlantic gas utility to review and analyze the lost and unaccounted for (LUF) gas levels experienced historically on its gas system. The effort required the team to review, analyze and validate the data and procedures used by the utility to reconcile and account for the gas received into its gas system and the gas delivered to its customers. Both accounting and operational issues were considered in the project, and a comprehensive structural process was developed for monitoring and evaluating LUF internally on an ongoing basis.

Mr. Feingold served as Project Manager on an assignment for a Southern gas utility to evaluate its accounting procedures and business systems for transportation service. In addition, Mr. Feingold was responsible for conducting a detailed review to identify improvements in the Company's practices and methods for managing lost and unaccounted-for gas levels.

For a Northeastern gas utility, Mr. Feingold performed a complete financial review, with analysis and recommendations, dealing with financial and sales forecasting methods, revenue instability problems and return on investment.

Mr. Feingold has participated in various gas utility-related projects involving the specification of user requirements, conceptual system design, and the testing and evaluation of software systems, which were both mainframe and PC-based. Specifically, these systems related to costing and rate design, gas transportation measurement, billing and accounting, revenue forecasting, gas supply planning and dispatching, marketing information systems and regulatory filing requirements.

His clients have included an Eastern utility holding company, two Southern gas utilities, numerous Eastern gas utilities, a Southern gas utility and a major Midwestern gas utility.

Mr. Feingold has also performed analyses of utility energy costs, energy consumption and demand levels, utility power contracts and plant operations to develop energy use and cost-minimizing strategies for several large industrial customers.

International Energy Assignments

Besides his extensive work experience in Canada, Mr. Feingold has participated in numerous international energy-related assignments. On behalf of the largest gas utility in Australia, Mr. Feingold addressed a wide range of costing, pricing, regulatory, competitive, organizational and transactional issues pertaining to gas deregulation and open-access transport services for the gas industry in Australia.

On behalf of an international gas corporation, Mr. Feingold reviewed and evaluated possible changes in the regulation of liquefied petroleum (LP) gas companies that were proposed by an International Energy Agency.

For an international electric utility, Mr. Feingold performed energy audits of selected commercial and industrial electric users and evaluated the country's potential energy conservation levels over forecasted five- and 10-year periods.

Mr. Feingold assisted an international gas utility in understanding U.S. gas regulatory policies, procedures and programs as part of the ongoing efforts to privatize the gas industry in that country.

On behalf of a government-owned gas manufacturing plant and associated gas distribution system located in Montevideo, Uruguay, Mr. Feingold conducted a rate structure analysis on a cost of service basis to evaluate the rate levels necessary to recover the facility's capital investment; operation and maintenance expenses and a fair return on investment over the 15-year lease term; and on a market or value of service basis, to evaluate the level of gas prices supportable relative to other competitive fuel sources.

Expert Testimony and Litigation Support

As an integral part of the services provided to clients in the above-discussed areas, Mr. Feingold has frequently prepared and presented expert testimony in support of his consulting activities. This testimony has been presented before the FERC and numerous state and provincial regulatory commissions.

Specifically, Mr. Feingold's expert testimony has dealt with the costing and pricing of energy-related products and services for gas and electric distribution and gas pipeline companies.

In addition to traditional utility costing and rate design concepts and issues, his expert testimony has addressed gas transportation rates, gas supply planning issues and activities, market-based rates, PBR concepts and plans, competitive market analysis, gas merchant service issues, strategic business alliances, market power assessment, merger and acquisition analyses, multi-jurisdictional utility cost allocation issues, inter-affiliate cost separation and transfer pricing issues, seasonal rates, cogeneration rates and pipeline ratemaking issues related to the importation of gas into the United States.

Finally, Mr. Feingold has extensive experience in providing other litigation support activities related to the development and preparation of interrogatories, cross-examination of expert witnesses and the technical aspects of legal briefs.

Mr. Feingold has presented expert testimony before the following regulatory bodies:

- Federal Energy Regulatory Commission
- National Energy Board of Canada
- Arkansas Public Service Commission
- British Columbia Utilities Commission (Canada)
- California Public Utilities Commission
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Georgia Public Service Commission
- Illinois Commerce Commission

- Indiana Utility Regulatory Commission
- Iowa Utilities Board
- Manitoba Public Utilities Board (Canada)
- Massachusetts Department of Public Utilities
- Michigan Public Service Commission
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- Montana Public Service Commission
- Nebraska Public Service Commission
- New Hampshire Public Utilities Commission
- New Jersey Board of Public Utilities
- New Mexico Public Regulation Commission
- New York Public Service Commission
- North Carolina Utilities Commission
- North Dakota Public Service Commission
- Ohio Public Utilities Commission
- Oklahoma Corporation Commission
- Ontario Energy Board (Canada)
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Philadelphia Gas Commission
- Quebec Natural Gas Board (Canada)
- South Dakota Public Utilities Commission
- Tennessee Regulatory Authority
- Utah Public Service Commission
- Vermont Public Service Board
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

PUBLICATIONS AND PRESENTATIONS

"Providing Natural Gas to Unserved andUnderserved Communities," American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, October 28-31, 2012.

"State Regulatory Issues Affecting Gas Utilities," American Gas Association Accounting Principles Committee Meeting, August 13-15, 2012.

"State Regulatory Landscape and Future Trends Affecting Utilities," American Gas Association Financial Forum, May 6-8, 2012.

"The Continuing Saga of Fixed Cost Recovery: Arguments in Utility Rate Proceedings ," American Gas Association Rate Committee Meeting and Regulatory Issues Seminar, August 28-31, 2011.

"State Regulatory Issues Affecting Utilities," American Gas Association Accounting Principles Committee Meeting, August 15-17, 2011.

"State Regulatory Issues Affecting Utilities," Edison Electric Institute/American Gas Association Accounting Leadership Conference, June 26-29, 2011.

"State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 15-17, 2011.

"2011 Forecast – Regulatory Issues and Risks for Utilities," American Gas Association Finance Committee Meeting, March 16-18, 2011.

"State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 17-19, 2010.

"*A Utility's Regulatory Compact: Where's the Right Balance?*" - RMEL Electric Energy Magazine, Issue 1 - 2010.

"Communicating Ratemaking and Regulatory Concepts to a Utility's Stakeholders," American Gas Association, Communications and Marketing Committee Meeting, March 16-17, 2010

"Managing Regulatory Risk," RMEL Workshop, October 8, 2009

"State Regulatory and Legislative Issues Affecting Utilities," American Gas Association Financial Forum, May 3-5, 2009.

"Financial Incentives for Energy Efficiency: Lessons Learned to Date," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 5-8, 2009.

"Breaking the Link Between Sales and Profits: Current Status and Trends," Energy Bar Association, Electricity Regulation and Compliance Committee, February 17, 2009.

"State Ratemaking Issues for Gas Distribution Utilities," Energy Law Journal, Volume 29, No. 2, 2008 (Report of the Natural Gas Regulation Committee).

"Current Issues in Cost Allocation and Rate Design for Utilities," SNL Energy, Utility Rate Cases Today: The Issues and Innovations, November 6, 2008.

"Current Issues in Revenue Decoupling for gas Utilities," American Gas Association, Financial and Investor Relations Webcast, October 16, 2008.

"*Addressing Utility Business Challenges Through the State Regulatory Process,"* American Gas Association, 2008 Legal Forum, July 20-22, 2008.

"*Earning on Natural Gas Energy Efficiency Programs,*" American Gas Association Rate and Regulatory Issues Conference Webcast, May 23, 2008.

"State Regulatory Directions: Utility Challenges and Solutions," American Gas Association Financial Forum, May 4, 2008.

"*Ratemaking and Financial Incentives to Facilitate Energy Efficiency and Conservation*," The Institute for Regulatory Policy Studies, Illinois State University, May 1, 2008.

"*Update on Revenue Decoupling and Innovative Rates*," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, March 10, 2008.

"Update on Revenue Decoupling and Utility Based Energy Conservation Efforts," American Gas Association, Rate and Regulatory Issues Conference Webcast, May 30, 2007.

"A Renewed Focus on Energy Efficiency by Utility Regulators," American Gas Association, Rate and Regulatory Issues Seminar and Committee Meetings, March 26, 2007.

"The Continuing Ratemaking Challenge of Declining Use Per Customer," American Public Gas Association, Gas Utility Management Conference, October 31, 2006.

"Understanding and Managing the New Reality of Utility Costs in the Natural Gas Industry," Financial Research Institute, Public Utility Symposium, University of Missouri – Columbia, September 27, 2006.

"Ratemaking and Energy Efficiency Initiatives: Key Issues and Perspectives," American Gas Association, Ratemaking Webcast, September 14, 2006.

"Ratemaking Solutions in an Era of Declining Gas Usage and Price Volatility," Northeast Gas Association, 2006 Executive Conference, September 10-12, 2006.

"Rethinking Natural Gas Utility Rate Design: A Framework for Change," American Gas Foundation and The NARUC Foundation, Executive Forum at Ohio State University, May 2006.

"Rate Design, Trackers, and Energy Efficiency – Has the Paradigm Shifted?" Energy Bar Association, Midwest Energy Conference, March 2006.

"Key Regulatory Issues Affecting Energy Utilities," American Gas Association, Lunch 'n Learn Session, November 2005.

"Decoupling, Conservation, and Margin Tracking Mechanisms," American Gas Association, Rate & Regulatory Issues – Audio Conference Series, October 2005.

"In Search of Harmony, [Utilities and Regulators] Respondents Weigh in with Needed Actions," Public Utilities Fortnightly, November 2005

"The Use of Trackers as a Regulatory Tool," Midwest Energy Association – Legal, Regulatory, and Government Relations Roundtable, October 9-11, 2005.

"Rate Design and the Regulatory Environment," American Gas Association Finance Committee Meeting, October 2005.

"Creative Utility Regulatory Strategies in a High Price Environment," American Gas Association Executive Conference, September 2005.

"Revenue Decoupling Programs: Aligning Diverse Interests," The Institute for Regulatory Policy Studies, Illinois State University, May 2005.

"Key Regulatory Issues Affecting Energy Utilities," American Gas Association Financial Forum, May 2005.

"*Energy Efficiency and Revenue Decoupling: A True Alignment of Customer and Shareholder Interests,*" American Gas Association Rate and Regulatory Issues Seminar and Committee Meetings, April 2005.

"Rate Case Techniques: Strategies and Pitfalls" American Gas Association, Rate & Regulatory Issues – Audio Conference Series, March 2005.

"Regulatory Uncertainty: The Ratemaking Challenge Continues," Public Utilities Fortnightly, Volume 142, No. 11, November 2004.

"Current Trends in Utility Rate Cases and Pricing: Surveying the Regulatory Landscape," Platts Rate Case & Pricing Symposium, October 25-26, 2004.

"State Regulatory Oversight of the Gas Procurement Function" Energy Bar Association, Natural Gas Regulation Committee, Energy Law Journal, Volume 25, No. 1, 2004.

"Cost Allocation Across Corporate Divisions," American Gas Association, Rate and Strategic Issues Committee Meeting, April 2003

"Unbundling Initiatives – How Far Can We Go?," American Gas Association Restructuring Seminar: Service and Revenue Enhancements for the Energy Distribution Business, December 2002.

"Utility Regulation and Performance-Based Ratemaking (PBR)," PBR Briefing Session sponsored by BC Gas Utility Ltd., April 2002.

"LDC Perspectives on Managing Price Volatility," American Gas Association, Rate and Strategic Issues Committee Meeting, March 2002.

"Can a California Energy Crisis Occur Elsewhere?," American Gas Association Rate and Strategic Issues Committee Meeting, March 2001.

"Downstream Unbundling: Opportunities and Risks," American Gas Association Rate and Strategic Issues Committee Meeting, April 2000.

"Form Follows Function: Which Corporate Strategy Will Predominate in the New Millennium?," American Gas Association 1999 Workshop on Regulation and Business Strategy for Utilities in the New Millennium, August 1999.

"Total Energy Providers: Key Structural and Regulatory Issues," American Gas Association, Rate and Strategic Issues Committee Meeting, April 1999.

"The Gas Industry: A View of the Next Decade," National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Accounts, 1998 Fall Meeting, September 1998.

"Regulatory Responses to the Changing Gas Industry," Canadian Gas Association, 1998 Corporate Challenges Conference, September 1998.

"Trends in Performance-Based Pricing," American Gas Association Financial Analysts Conference, May 1998.

"Unbundling – An Opportunity or Threat for Customer Care?," presented at the American Gas Association/Edison Electric Institute Customer Services Conference and Exposition, May 1998.

"Experiences in Electric and Gas Unbundling," presented at the 1997 Indiana Energy Conference, December 1997.

"Asset and Resource Migration Strategies," presented at the Strategic Marketing for the New Marketplace Conference sponsored by Electric Utility Consultants, Inc. and Metzler & Associates, November 1997.

"The Status of Unbundling in the Gas Industry," presented at the American Gas Association Finance Committee, March 1997.

Seminar organizer and co-moderator at the American Gas Association, *"Workshop on Unbundling and LDC Restructuring,"* July 1995.

"State Regulatory Update," presented at the American Gas Association - Financial Forum, May 1995.

"Gas Pricing Strategies and Related Rate Considerations," presented before the Rate Committee of the American Gas Association, April 1995.

"Avoided Cost Concepts and Management Considerations," presented before the Workshop on Avoided Costs in a Post-636 Industry, sponsored by the Gas Research Institute and Wisconsin Center for Demand-Side Research, June 1994.

"DSM Program Selection Under Order No. 636: Effect of Changing Gas Avoided Costs," presented before the NARUC-DOE Fifth National Integrated Resource Planning Conference, Kalispell, MT, May 1994.

"A Review of Recent Gas IRP Activities," presented before the Rate Committee of the American Gas Association, March 1994.

Seminar organizer and co-moderator at the American Gas Association seminar, *"The Status of Integrated Resource Planning,"* December 1993.

"*Industry Restructuring Issues for LDCs, presented before the American Gas Association,"* Advanced Regulatory Seminar, University of Maryland, 1993-1996.

"Acquiring and Using Gas Storage Services," presented before the 8th Cogeneration and Independent Power Congress and Natural Gas Purchasing '93, June 1993.

"*Capitalizing on the New Relationships Arising Between the Various Industry Segments: Understanding How You Can Play in Today's Market*," presented before the Institute of Gas Technology's Natural Gas Markets and Marketing Conference, February 1993.

"The Level Playing Field for Fuel Substitution (or, the Quest for the Holy Grail)," presented before the 4th Natural Gas Industry Forum - Integrated Resource Planning: The Contribution of Natural Gas, October 1992.

"Key Methodological Considerations in Developing Gas Long-Run Avoided Costs," presented before the NARUC-DOE Fourth National Integrated Resource Planning Conference, September 1992.

"Mega-NOPR Impacts on Transportation Arrangements for IPPs," co-presented before the 7th Cogeneration and Independent Power Congress and Natural Gas Purchasing '92, June 1992.

"Cost Allocation in Utility Rate Proceedings," presented before the Ohio State Bar Association - Annual Convention, May 1992.

"The Long and the Short of LRACs," presented before the Natural Gas Least-Cost Planning Conference April 1992, sponsored by Washington Gas Company and the District of Columbia Energy office.

Seminar organizer and moderator at the American Gas Association seminar, *"Integrated Resource Planning: A Primer,"* December 1991.

Session organizer and moderator on integrated resource planning issues at the American Gas Association Annual Conference, October 1991.

"Strategic Perspectives on the Rate Design Process," presented before the Executive Enterprises, Inc. conference, "Natural Gas Pricing and Rate Design in the 1990s," September 1990.

"Distribution Company Transportation Rates," presented before the American Gas Association–Advanced Regulatory Seminar, University of Maryland 1987-1992.

"Design of Distribution Company Gas Rates," presented before the American Gas Association - Gas Rate Fundamentals Course, University of Wisconsin – Madison, Graduate School of Business, 1985-2007.

Seminar organizer, speaker and panel moderator at the American Gas Association seminar, *"Natural Gas Strategies: Integrating Supply Planning, Marketing and Pricing,"* 1988-1990.

"Local Distribution Company Bypass - Issues and Industry Responses," (Co-author) June 1989.

"So You Think You Know Your Customers!," presented before the American Gas Association–Annual Marketing Conference, April 1990.

"Gas Transportation Rate Considerations - A Review of Gas Transportation Practices Based on the Results of the A.G.A. Annual Pricing Strategies Survey," presented before the Rate Committee of the American Gas Association, April 1985-1991.

"Market-Based Pricing Strategies - Targeted Rates to Meet Competition," presented before the American Gas Association Annual Marketing Conference, March 1989.

"Gas Rate Restructuring Issues - Targeted Prices to Meet Competition," presented before the Fifteenth Annual Rate Symposium, University of Missouri, February 1989.

"Gas Transportation Rates - An Integral Part of a Competitive Marketplace," American Gas Association, Financial Quarterly Review, Summer 1987.

"Gas Distributor Rate Design Responses to the Competitive Fuel Situation," American Gas Association, Financial Quarterly Review, October 1983.

"Demand-Commodity Rates: A Second Best Response to the Competitive Fuel Situation," presented before the American Gas Association, Ratemaking Options Forum, September 1983.

"Current Rate and Regulatory Issues," presented before the National Fuel Gas Regulatory Seminar, July 1986.

EDUCATIONAL AND TRAINING ACTIVITIES

Past Chairman, Rate Training Subcommittee, Rate and Strategic Issues Committee of the American Gas Association.

Seminar organizer and co-moderator at the American Gas Association, "Workshop on Unbundling and LDC Restructuring," July 1995.

Course organizer and speaker at the annual industry course, American Gas Association – Gas Rate Fundamentals Course, University of Wisconsin – Madison, and University of Chicago – School of Business, 1985 – 2012.

Course organizer and speaker at the annual industry course, American Gas Association – Advanced Regulatory Seminar, University of Maryland - College Park and the University of Chicago – School of Business, 1987 –1992, and 2012.

Co-founder, course director and instructor in the annual course, "Principles of Gas Utility Rate Regulation" sponsored by The Center for Professional Advancement 1982-1987.

Contributing Author of the Fourth Edition of "Gas Rate Fundamentals," American Gas Association, 1987 edition.

Organizer, Editor, and Contributing Author of the upcoming Fifth Edition of "Gas Rate Fundamentals," American Gas Association (in progress).

H. EDWIN OVERCAST

Director

Strategic Planning

Mergers & Acquisitions

Due Diligence Support

Pricing and Rate Design

Economic Analysis

Legislative Analysis

Industry Restructuring

Organizational Management

Competitive Market Analysis

Expert Testimony

Open Access and Unbundling Implementation

Education
Virginia Polytechnic Institute and State University, Ph.D., 1972

King College, BA in Economics, 1969

Years Experience
38 years

Joined Black &Veatch
2005

A specialist in the practice areas of regulatory policy and economics, energy pricing and rate design, economic analysis, strategic planning, legislative analysis, industry restructuring analysis, competitive analysis and open access and unbundling implementation.

Professional Employment

1999-Present	Energy Management Solutions, Black & Veatch Company *Director*
1989-1999	AGL Resources, Inc. *Vice President, Strategy Planning and Business Development*
1978-1989	Northeast Utilities *Director, Rates and Load Research*
1975-1978	Tennessee Valley Authority *Economist, Rate Branch*
1990-1995	Georgia State University *Instructor, Economics (part-time)*
1974-1975	East Tennessee State University *Assistant Professor of Economics* *Associate Director of Bureau of Business and Economic Research*
1972-1974	Elon College *Assistant Professor of Economics*

Professional Experience

Utility Ratemaking and Regulatory Policy Analysis

Dr. Overcast has been responsible for a wide variety of electric and gas pricing and cost analyses. He has had operational and strategic responsibility for both the electric and gas utility tariff design, including comprehensive unbundling cost analyses and tariff administration. He has provided expert testimony before state and federal regulatory agencies on a number of rate and regulatory policy issues related to unbundling, cost of service (marginal, fully allocated and unbundled cost studies, alternative regulation), performance-based regulation and price cap regulation, strategic and market-sensitive pricing, bypass economics, integrated resource planning, weather normalization adjustments, sales and revenue forecasts, pro forma adjustments and revenue requirements, rate and regulatory policy for cogenerators, energy buy-back rates, revenue sharing and adjustment mechanisms, competition and fuel switching, transmission pricing and a variety of policy issues including unbundling proposals, line extension policy and rate discounting and recovery. He has testified before the FERC in electric, gas and oil pipeline matters. He has also testified before provincial regulatory agencies in Canada on electric and gas matters.

Dr. Overcast has also testified in both federal and state courts on matters related to rate design, mergers and acquisitions, anti-trust and regulatory policy. He has testified before both federal and state legislative bodies on deregulation, restructuring, regulatory policy and other issues arising out of restructuring legislation including stranded cost recovery, competition and public policy.

Economic Analysis

Dr. Overcast has been responsible for variety of economic analyses related to merger and acquisition, new business development, bypass, special contracts, marginal cost, time-of-use pricing, service area expansion, pipeline and other facilities expansion, competitive pricing, anti-trust, municipalization, new product development and others. He has provided forecasts of sales, prices, peak day and other similar analyses for planning and regulatory proceedings. He has prepared economic analyses of unbundling and the potential impact on revenue, earnings, stock price and economic value added.

Strategic Planning

Dr. Overcast has been responsible for the development of strategic plans for both the regulated and non-regulated business units. His experience includes corporate reorganization to position a regulated enterprise to open its markets to competition; the preparation of business plans for regulated and non-regulated companies including energy marketing initiatives and other service providers. He has helped to prepare estimates of financial performance for unregulated energy marketing companies and evaluated joint ventures and a variety of retail marketing plans.

He has participated in the planning for a variety of regulatory initiatives. He has had primary responsibility for the development of the legislative model used in Georgia for permitting open access and unbundling.

Legislative Analysis

Dr. Overcast has been responsible for the assessment of a variety of legislative proposals in the areas of the regulatory policy, restructuring analysis, competition and unbundling. He has participated extensively in the legislative process, testifying before committees, negotiating with various interested parties, and working with the staff of legislators. He has worked extensively with lobbyists providing background material and responding to questions raised during the legislative process. He was appointed by the lieutenant governor to serve on a study committee of the Georgia legislature reviewing issues related to the impact of deregulation on franchise fees.

Competitive Analysis

Dr. Overcast has prepared extensive analysis of competition for residential, commercial and industrial customers. That analysis has included comparisons of total and marginal cost for end-use applications, alternate production technologies, alternate fuel analysis, bypass pipelines, self-generation, cogeneration and other competitive analyses. He has also prepared extensive analysis of potential competitors in the opening of markets. He has managed the competitive alternate fuel program for gas utilities and developed a discount analysis required to avoid uneconomic bypass and to maximize revenue contribution from such discount programs. He has also negotiated contracts to avoid bypass for both gas and electric customers and to displace liquid fuels in vehicles.

Open Access and Unbundling Implementation

Dr. Overcast has had the unique experience of playing a significant role in the complete open access and unbundling implementation for natural gas LDCs. He was instrumental in the design of the model adopted by the Georgia legislature and testified throughout the legislative process on the proposed legislation. After the legislation became law, he oversaw the rate case filing required to implement open access and unbundling. His experience includes cost analysis and rate design for an open access tariff. He has been directly involved in the many facets of unbundling service to all retail customers. His firsthand experience provides him with insight and a unique perspective with respect to the questions that arise as a utility—gas or electric—unbundles.

Publications and Presentations

"Restoring Financial Balance," Public Utilities Fortnightly, November 2011

"Impact of Volatile Fuel Prices on Electric Costs: Stakeholder Tactics," Natural Gas and Electricity, August 2008

"Fixed Cost Recovery: An Inconvenient Truth," American Gas, June 2007

"The Hidden Risks of Regulation and Their Effects on Utility Returns," Natural Gas and Electricity, June 2006.

"Electric Utilities and Risk Compensation, with Richard J. Rudden, Howard S. Gorman and Leonard S. Hyman, EEI Monograph, June 2006.

"Energy Competition Knows No Bounds," presented at the DOE-NARUC North American Summit on Harmonizing Business Practices in Energy Restructuring, November 2000.

"Load Research Troubleshooting—A Pragmatic Approach," presented to the Northeast Regional AEIC Load Research Conference, September 1988.

"Using Load Research Data to Assess Competitive Threats," presented to the Northeast Regional AEIC Load Research Conference, September 1987.

"Using Load Research Data to Design and Analyze Commercial and Industrial Time-of-Day Rates," presented to the International Association of Energy Economists, 1987.

"Pricing in Competitive Markets," presented to the PG&E Energy Expo 1986, April 1986.

"Philosophy of Rate Design," presented to the China Energy Research Society of the China Association for Science and Technology, June 1985.

"Competition in the U.S. Electric Markets," presented to the North American Energy Markets Conference, March 1985.

"Electric Utility Competition in the United States," *Energy Exploration & Exploitation*, 1986.

"Avoided Costs—The Balancing of Objectives," *Proceedings of the Eighth Annual Symposium on Problems of Regulated Industries*, 1982.

"An Overview of Alternative Tariff Structures," *Proceedings of the Eighth Biennial Conference of the Central Electricity Generating Board*, Ontario Hydro and the Tennessee Valley Authority (co-authored).

"A Differential Approach to the Repeated Prisoner's Dilemma," *Theory and Decision*, 1971 (co-authored).

"Problems and Perspectives in Public Choice," *Public Finance and Public Choice*, A Training Program for Local Public Officials, 1974.

"The Economic Impact of the East Tennessee State University Medical School," *The Bureau of Business and Economic Research*, East Tennessee State University, 1975.

"Determinants of the Demand of Substandard Housing," presented at the Western Economic Association Meeting, 1970 (co-presented).

Honors

Who's Who Worldwide—Business Leaders

Citizens Ambassador Program of People to People International - IAEE Delegate, 1985

SGA Outstanding Professor, Elon College, 1973-1974

Omicron Delta Epsilon, honorary fraternity in Economics

H.B. Earhart Foundation Fellow 1970-1971 and 1971-1972

Woodrow Wilson Fellowship Nominee, 1969

National Science Foundation Undergraduate Internship, 1968

Other Activities

Appointed by Georgia Lt. Governor to serve on Joint Study Committee on Franchise Fees and Conditions, Rights of Way and Tax Implications of Competitive Markets.

Instructor - AGA and EEI Rate Fundamentals Courses

Conference speaker - SGA, SEGA, AGA, NARUC, trade associations and seminars

Vice President - A Better Chance, Glastonbury, CT

Member and Vice Chairman - Glastonbury Sewer Commission

Appendix D4

DEFERRAL OF EXPENDITURES DURING 2004 PBR

1. CONCERNS RAISED FROM 2004 PBR PLAN

Although not specifically raised as an issue during the term of the 2004 Plan, in the following two RRAs that set rates for 2010 through 2013, both the Commission and Interveners raised a concern about the sustainability of the shared savings that occurred during the 2004 -2009 period. The following is an excerpt from the 2012-2013 RRA Decision on this point:

> *"BCOAPO and CEC both identify that any cost deferrals during the PBR period, as opposed to sustained cost savings, have a higher cost to customers than when they actually incurred. This is due to the PBR mechanism allowing the shareholder to take in 50 percent of the cost savings. Therefore, when the cost is incurred outside of the PBR period, the ratepayer, in effect, pays again resulting in a cost to the ratepayer of 150 percent of the actual expenditure."*

FEI addressed the issue in prior applications when it was raised, but will address it again here given that FEI is proposing to return to PBR. In summary:

- The issue was largely academic in the context of the previous PBR, since there was very little in the way of cost deferrals during the 2004-2009 PBR period;
- The assumption that a deferral of spending will necessarily result in customers paying 150 percent of the actual expenditure is not valid for capital items, and is only valid in limited circumstances for O&M items; and
- FEI has proposed two modifications to its PBR Plan that should address any remaining concerns.

Although there was an expressed concern about the deferral of costs during the PBR period, this did not occur in any significant way in the 2004-2009 PBR. FEI has included Attachment 1 to Appendix D4 which is a copy of Exhibit B-58 from the oral hearing for the 2012-2013 RRA, which summarizes the evidence related to activities that were deferred. Exhibit B-58 shows that a total of approximately $1.4 million in O&M was deferred to the years following 2009, and FEI could not identify any instances of a deferral of capital spending. $1.4 million represents only about 0.7 percent of the annual net O&M spending during the 2004-2009 PBR period and just more than 0.1 percent of the aggregate O&M spending over the six years.

The critique focusses on one element of the 2004 PBR Plan. The settlement was an overall package, and should be considered in that light. There were significant savings passed on to customers as a result of the 2004-2009 PBR – through the productivity improvement factor, and through incremental O&M savings and through capital savings above the productivity improvement factor built into rates.

2. IMPACT OF ANY DEFERRED SPENDING

As stated above, the vast majority of FEI's savings during the last PBR period were achieved by reducing costs, not deferring expenditures. In any event, the concern expressed by stakeholders is only realistic in very limited circumstances, and would not be valid for most deferred expenditures.

FEI does agree that in certain situations, a deferral of O&M during the PBR period can result in customers paying 150 percent of the cost. This situation can arise if the O&M amount that is deferred (or saved in the PBR period) is captured by the earnings sharing mechanism (that is, the savings is over and above the savings that are built into rates through the productivity improvement factor). This situation can occur, but it could equally be true that the savings instead were realized in achieving the productivity improvement factor. In this latter case, customers are not paying for these savings at all during the PBR Period, and the argument that they end up paying 150 percent does not hold.

In terms of capital, since the lower capital expenditures (i.e. plant additions) would be embedded in the re-based opening plant balances which are depreciated over many years, the benefits to ratepayers of these savings continue long past the PBR period. At the very least, the prudent deferral of capital spending creates a present value benefit for customers. This present value benefit increases with each year of deferral.

The following table illustrates the benefits to customers of deferring capital expenditures based on an asset assumed to have a 3.27 percent depreciation rate (the average depreciation rate for the 2013 plant in service). The analysis is based on an assumed three year deferral of the project and a five year PBR term.

NPV of Cost of Service Comparison of a $100,000 Capital Expenditure
($000)

Line	Average Depreciation Rate of 3.27%, 34 Year Evaluation Period[1]				
1	Original Year of Capital Addition[2]	2016	2017	2018	2019
2	Year of Deferred Capital Addition[3]	2019	2020	2021	2022
3	NPV Normal COS[3]	122.2	123.9	127.1	129.7
4	NPV Deferral COS[4] + PBR Earnings Sharing[5]	122.8	120.5	117.9	114.1
5	Net Change	**0.5%**	**-2.7%**	**-7.3%**	**-12.0%**

Notes:

1: The 34 year NPV is based on 31 years to fully depreciate the asset plus 3 years for the deferral

2: Year when capital was originally scheduled to be spent

3: Year when capital is spent after 3-year deferral

4: NPV of cost of service related to Original Year (Line 1)

5: NPV of cost of service related to Deferred Capital (Line 2)

6: PBR earnings sharing assumed for balance of the PBR term (i.e. through 2018)

The analysis provided in the table demonstrates that the three year deferral of capital produces a benefit for customers through a lower NPV in all cases except the first one in which the three year deferral is all within the PBR term (which results in a minor NPV increase of less 0.5 percent). Based on this analysis, it can be concluded that a deferral of capital spending is of benefit to utility customers.

3. MODIFICATIONS TO PBR PLAN

As with the previous PBR period, FEI will focus on O&M efficiencies, rather than deferrals, recognizing that the most direct customer benefit comes from the former. FEI also intends to focus on sustainable efficiencies in its capital programs and expects capital expenditure deferrals of the type discussed above to be very limited. As illustrated above, most instances of deferring capital expenditures in this fashion would actually yield net benefits for customers. More fundamentally, in terms of assessing the past PBR Plan, the real focus should be on the performance of the plan overall, as there was "give and take" in the design of the 2004 PBR Plan to result in an overall package that was fair to both customers and the utility. FEI is nevertheless proposing modifications to the 2004 Plan in this PBR Plan that should address any residual concerns regarding deferred capital and O&M costs.

The elements of the proposed PBR Plan that should address concerns regarding deferrals are as follows:

1. FEI has proposed a capital expenditure deadband outside of which rebasing would occur during the PBR term. That is, if total regular capital expenditures vary by more than 10 percent above or below the total formula-based capital expenditures in any year, the opening plant in service for ratemaking purposes in the following year will be adjusted up or down by the amount that actual capital expenditures vary outside of the 10 percent deadband from the formula-based amount. This will limit the impact of any capital savings during the PBR Period that would be shared between the customer and Company, and limit the amount of rebasing that would occur after the PBR Period.

   FEI believes this adjustment to the PBR Plan provides a suitable balance between having a capital incentive in the Plan that motivates the Company to seek efficiencies in its capital spending plans for the long term benefit of customers and the concern expressed by customers about the large difference that accrued in the 2004-2009 PBR Plan between rate base for ratemaking purposes and actual rate base. If the same 10% deadband on total capital expenditures had been in place during the 2004-2009 PBR, the cumulative difference between the formula-based and actual amounts included in rate base would have been reduced from $80 million to $47 million.

2. As part of the Efficiency Carryover Mechanism, FEI is proposing to add an O&M component to the mechanism that will incent FEI to continue to realize O&M savings in the final years of the PBR. Having both capital and O&M components in the ECM as proposed will provide an incentive of the same strength in each year of the PBR term for FEI to pursue new efficiencies. This means FEI will have the same enhanced motivation

in year 5 as in year 1 (and years in between) to keep costs down for the longer term benefit of customers. The consistency of the incentives throughout the five year term should give comfort to customers that the rate base and base O&M levels at the end of the PBR term will reflect significant productivity improvements and provide an appropriate base for rates going forward.

In summary, the proposed modifications to the PBR Plan are reasonable in the context of the overall PBR Plan, and provide a response to the concerns raised in past proceedings regarding deferral of expenditures beyond the PBR period.

FortisBC Energy Utilities (“FEU”)
2012-2013 REVENUE REQUIREMENTS AND NATURAL GAS RATES APPLICATION

UNDERTAKING No. 30

HEARING DATE:	October 11, 2011
TRANSCRIPT REFERENCE:	Volume 7, Page 1150, Lines 11 to 24
REQUESTOR:	Mr. Fulton
WITNESS:	Mr. Bell
QUESTION:	Please quantify the savings that resulted from deferring activities.

RESPONSE:

As indicated by Mr. Loski (Transcript Volume 6, page 1023, lines 3 to 14), the issue of savings related to deferred activities during the PBR period was significantly canvassed in TGI’s 2010-2011 RRA proceeding. The FEU note that the issue was not addressed in the present Application as it does not impact the 2012 and 2013 test period and the issue was minimally canvassed in the IRs in this proceeding. Since the request was made, Mr. Bell and his staff have had the opportunity to check past records from the period in question and the information provided in the previous revenue requirements application when this issue was resolved. The complete detail can now be provided. Aspects of Mr. Bell's responses during the hearing, which were based on his recollection, also require correction.

<u>Savings related to deferred activities during PBR:</u>

Savings related to deferred activities during the PBR was discussed in the 2010-2011 TGI RRA and the costs of these deferred activities are described in the attached responses to BCUC IR 1.75.1, BCUC IR 1.77.1 and BCUC IR 2.100.1 from TGI’s 2010-2011 RRA proceedings. These IR responses set out the amounts of forecast expenses related to deferred activities during the PBR period. As indicated in these IR responses, these costs were all forecast to be incurred in 2010 and no costs related to deferred savings under PBR were forecast for 2011 *or beyond*. The FEU confirm that no deferred costs from the PBR are forecast to be incurred in 2012 or 2013.

At Transcript Volume 6, page 1016 line 22 to page 1017, line 5 and Transcript Volume 7, page 1153, lines 3 to 4, Mr. Bell referred to deferred bridge inspections. As indicated in the attached response to the 2010-2011 TGI RRA, BCUC IR 1.75.1, the deferred activity was not actually the inspections, but the bridge crossing repairs which includes activities such as painting at bridge crossings and replacement and maintenance of hangars and

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other gas infrastructure components at the bridge crossing. Mr. Bell confirms that he misspoke and that he meant to refer to bridge maintenance, such as painting, as he referred to at Transcript Volume 6, page 1016, line 23 to page 1017, line 5.

<u>Reduced Meter Recall Activity:</u>

At Transcript Volume 7, pages 1149 to 1152, Mr. Bell also discussed the "deferral" of meter recall activity during the PBR period. As explained below, this was not actually a "deferral" but a reduction in the residential meter recall or exchange activity. The reduction of meter exchanges during the PBR period and in particular years 2006, 2007 and 2008 is summarized in the 2010-2011 TGI RRA on page 188 as follows:

> *Prior to 2006, Terasen Gas managed the residential meter fleet to a 28 year life span enabled by one maintenance and recondition operation at the midpoint of this 28 year life. This resulted in a meter recall frequency of 14 years. Communications with vendors, ongoing discussions within the Canadian Gas Association Measurement Committee and the company's own internal analysis, provided Terasen Gas the confidence to target a 20 year life span for the residential meter fleet without a mid-life recondition operation. <u>This allowed Terasen Gas to temporarily reduce the number of meter recalls over the period 2006 - 2008 to bring the demographics of the meter fleet in line with a 20 year life expectancy which provided both customers and shareholders the cost benefits of previous investment in the fleet.</u>* [Emphasis added.]

The level of meter replacement activities was presented in Table B-1-30 on page 188 of the 2010-2011 TGI RRA. As indicated there, the number of meter exchanges drops from the 2005 level of 46,900 to 28,446 in 2006, 30,417 in 2007, 33,275 in 2008 and back up to 46,700 in the 2009 projection. Approximately 48,000 recalls (16,000 per year) were deferred over the three-year period.

This temporary reduction in the number of meter recalls was further discussed in response to the 2010-2011 TGI RRA, BCUC IR 1.134.1 as follows:

> *One of the activities conducted within Terasen Gas to ensure the cost effective and reliable operation of the meter fleet is to adjust the meter recall schedule based on the meter fleet age distribution and the results of the performance sampling program. Between 2006 and 2008, the decision to operate residential meters to the full life expectancy of 20 years, coupled with the positive results from sampled meter performance tests, allowed the company to temporarily reduce the total number of scheduled meter recalls. Therefore, no meter recalls were deferred during the time frame referenced within the question. All meter recalls were scheduled at times that were optimal in terms of operational reliability. Finally, by temporarily reducing the number of meter recalls during this period, both customers and shareholders were allowed to benefit from the savings in O&M and capital expenditure.*

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In addition, the responses to BCUC IR 1.119.2 and 2.119.3 stated:

> *The average life expectancy of 20 years for residential meters was not applied for a closed period of three years but instead remains the ongoing target for long term planning by Terasen Gas. In 2006, a decision was made to operate residential meters to a life expectancy of 20 years. The temporary reduction of meter recalls served to bring the demographics of the meter fleet in line with a 20 year life expectancy and resulted in significant Capital and O&M savings (see the response to BCUC IR 2.119.3).*
>
> *The 20 year life span relates to the Terasen Utilities' experience in average meter life expectancy determined through a statistical sampling monitoring process and validated through discussions with vendors and employees of utilities represented on the Canadian Gas Association Measurement Committee. As such, the data used to determine this target life expectancy was gathered over multiple years to establish trends in residential meter performance which has allowed Terasen Gas to forecast the long term performance of meters currently deployed within its residential meter fleet. Similarly, it is expected that any future adjustment to the targeted average life expectancy for the residential meter fleet will only be done after extensive study of trends in meter performance over an extended period, combined with ongoing discussions with other participants in the gas measurement industry.*
>
> *…*
>
> *<u>For clarity, the reduction was not a deferral.</u> In 2006, a decision was made to operate residential meters to a life expectancy of 20 years. The temporary reduction of 62,203 meter recalls served to bring the demographics of the meter fleet in line with a 20 year life expectancy and resulted in significant Capital and O&M savings as compared to the original policy. There is no subsequent increase in activity or cost in 2010 or 2011 that can be attributed to the temporary reduction in meter exchange activity.* [Emphasis added.]

The response to the 2010-2011 TGI RRA, BCUC IR 2.119.3 estimated the capital and O&M savings due to the reduction in meter recall activity. That response is also attached.

75.0 Reference: Operations and Maintenance Expenditures

Maintenance Deferred during PBR

Part III, Section C, Tab 6, p. 357, par. 1

"To continue to fulfil our recognized role as a respected and trusted operator providing safe, reliable and cost effective utility service to customers, Terasen Gas forecasts additional O&M funding required for its ongoing operations and activities. These include ... maintenance which has been pragmatically deferred during the PBR Period but cannot be deferred any longer."

75.1 Please provide details of the maintenance activities and related costs deferred, indicate which will now be required in the 2010 or 2011 period, and detail the reference in this Application.

Response:

O&M maintenance activities and related costs deferred from the PBR period into the 2010 period total to approximately $870K with none in 2011. Maintenance activities pragmatically deferred during the PBR period but that cannot be deferred any longer include:

1. $200K - Valve and maintenance repairs
2. $170K – Station heater maintenance
3. $30K - Bridge and aerial cross repairs
4. $25K - Station ground maintenance
5. $160K - Tools and equipment maintenance
6. $285K – Building maintenance

$870K – Total Deferred and Requested in 2010

Item numbers 1 to 4 are listed on page 362 of the Application in table C-6-16. During the PBR period, there were no changes in survey or inspection procedures. All regularly scheduled preventive maintenance, surveys and inspections were completed as per Code and Terasen Gas requirements. No work was deferred that was considered critical to the ongoing safe operation of the natural gas distribution system. Maintenance expenditures were managed and prioritized based on a corporate risk profile with higher risk items addressed first. Please refer to TGI's response to BCUC IR 1.8.2 for further discussion of this approach.

Item number 5, tools and equipment maintenance is referenced on page 390. Maintenance on tools and equipment used in field operations has been deferred during the PBR period without impact to operations. However, much of this maintenance work is directed toward industry specific tools and equipment that would otherwise be expensive to replace through purchase or manufacture. As such, these additional maintenance activities are prudent and required in order to continue providing tools and equipment to our field employees in a cost effective manner.

Item number 6 is listed on page 390 of the Application. The additional facilities maintenance comprised of activities such as painting, fence replacement, maintenance on roofs, etc is not in essence deferred expenditures but more cyclical activities in nature that have varying frequencies. In 2011, there is reduction of ($160K) reflecting the completion of maintenance completed in 2010.

TGI continues to defer low risk or low priority items as it has done during the PBR period as part of its prudent management of expenditures.

77.0 Reference: Operating & Maintenance

Non-Maintenance Deferrals during BPR

Part III, Section B, Tab 1, p. 161, par. 1

"Deferring activities and related costs where safe and prudent to do so, particularly where the activities were of a cyclical nature."

77.1 Please provide details of the non-maintenance activities and related costs deferred, indicate which will now be required in the 2010 or 2011 period, and detail the reference in this Application.

Response:

Non-maintenance activities pragmatically deferred during the PBR period but that cannot be deferred any longer include:

1. $250K - Vegetation ($150K) and pipeline identification ($100K)
2. $150K - Data integrity improvements
3. $120K - Class location study

$520K – Total Deferred and Requested in 2010

The above items are listed on page 362 of the Application in table C-6-16. These non-maintenance expenditures were managed and prioritized based on a corporate risk profile with higher risk items addressed first, and Terasen Gas intends to continue with this prudent management of these types of expenditures. Please refer to TGI's response to BCUC IR 1.8.2 for further discussion of this approach.

100.0 Reference: Operations and Maintenance Expenditures

Exhibit B-4, BCUC 1.75.1 and 1.77.1

Items Deferred during BPR

Maintenance deferred during BPR was $870 thousand and non-maintenance deferred during BPR was $520 thousand. Expensing these costs in 2010 will result in the ratepayer incurring the entire cost whereas the ratepayer had 50 percent of the savings in the year deferred.

100.1 Since these expenditures are managed and prioritized based on a corporate risk profile with higher risk items addressed first, where will these expenditures rank in relation to Customer/Stakeholder Expectations identified in BCUC 1.72.2? Specifically, will these deferred expenditures be acted upon before the Customer/Stakeholder Expectations?

Response:

Before answering the question, TGI wishes to address the statement in the preamble, which appears to overlook the fact that the expenses for maintenance and non-maintenance referred to in the preamble were, and remain, expenses related to the ongoing operation of the utility. As such, they are costs legitimately borne by the customers in their entirety. The deferral of lower risk items as TGI has done is a part of prudent management, which TGI did prior to the PBR Period and during the PBR Period, and will continue to do beyond the PBR Period. The PBR Agreement incentive mechanism allocated benefits from these O&M expense deferrals equally to customers and the shareholder, but the expiry of the PBR Agreement does not have the effect of requiring the shareholder to incur half the cost of expenditures legitimately required for the ongoing provision of service to customers.

Maintenance deferred during the PBR Period in the order of $870K as referenced on Page 357 of the RRA and the response to BCUC IR 1.75.1, and non maintenance deferred in the order of $520K as referenced on Page 161 of the RRA and the response to BCUC IR 1.77.1 have both been prioritized as being necessary expenditures in the 2010 year. Given that these items have evolved over time from a lower risk profile where they were capable of being pragmatically deferred to that of a high risk profile where deferral would involve a high degree of risk, they will be incurred in 2010 and not deferred until 2011 or beyond.

Expenditures classified in the RRA as Customer/Stakeholder Behaviours and Expectations, quantified as $4.5 million on Table C-6-3, and referenced in the response to BCUC IR 1.72.2 are also expected to be incurred in 2010. These expenditures are of a different nature and present a different type of risk profile than those of the preceding paragraph. Based on a corporate risk profile, these expenditures are all categorized as being necessarily incurred in 2010.

In sum, the expenditures included in the Application are for the provision of service to customers and are accordingly appropriately borne by customers. TGI will continue to look for ways to defer non essential expenses, but the expenses included in the Application are necessary for the continued delivery of safe and reliable service to customers.

performance which has allowed Terasen Gas to forecast the long term performance of meters currently deployed within its residential meter fleet. Similarly, it is expected that any future adjustment to the targeted average life expectancy for the residential meter fleet will only be done after extensive study of trends in meter performance over an extended period, combined with ongoing discussions with other participants in the gas measurement industry.

> "Finally, by temporarily reducing the number of meter recalls during this period, both customers and shareholders were allowed to benefit from the savings in O&M and capital expenditure."

119.3 What are the total savings to customers resulting from the reduction and subsequent increase in O&M and capital expenditures over the period 2006 through 2011?

Response:

For clarity, the reduction was not a deferral. In 2006, a decision was made to operate residential meters to a life expectancy of 20 years. The temporary reduction of 62,203 meter recalls served to bring the demographics of the meter fleet in line with a 20 year life expectancy and resulted in significant Capital and O&M savings as compared to the original policy. There is no subsequent increase in activity or cost in 2010 or 2011 that can be attributed to the temporary reduction in meter exchange activity.

See table below for detailed quantities:

	2006	2007	2008	2009	Cummulative
Meter recalls planned prior to "20 Year" policy change	49,634	49,806	50,647	50,954	201,041
Actual Meter Recalls	28,446	30,417	33,275	*46,700	138,838
Difference in meter recalls	21,188	19,389	17,372	4,254	62,203

* "***Actual Meter Recalls***" are projected for 2009.

Cumulative O&M savings of $1.6 million, of which the customers share was approximately $800 thousand (50%), were as a result of 62,203 fewer customers appointments required for field exchange activity and 21,118 fewer meters recalled for repair. See table below:

	Reduced Activity 2006 - 2009	Unit Cost	O&M Savings 2006 - 2009
Customer appointments	62,203	$ 5.50	$ 342,117
Meters recalled for repair	21,188	$ 59	$ 1,250,092
		Total O&M Savings	$ 1,592,209

Cumulative capital savings of $17.4 million were as a result of 41,015 fewer meters recalled for retirement and replacement. See table below:

	2006	2007	2008	2009	Cummulative
***Capital Cost Projection prior to "20-year" policy change ($millions)**	15.2	15.7	16.2	16.8	63.9
****Actual Capital Costs ($millions)**	11.9	10.3	11.8	***12.5	46.5
Difference ($millions)	3.3	5.4	4.4	4.3	17.4

* "***Capital Cost Projection prior to 20-year policy change***" from 2004 Annual Review for 2005 Revenue Requirements Tab B-1, page 5 Other Regular Capital, "Meters-Replacement"

** "***Actual Capital Costs***" from Part III Section B page 188 of the Application, "Meters - Exchange/Other"

*** Actual Capital Costs for 2009 are projected

Please note that the savings as described in the above tables were determined based on the difference between the original policy and the revised policy, and not based on a calculation of the sharing of actual vs. formula based O&M and capital amounts over the years 2006 to 2009.

BCUC 2012 Generic Cost of Capital

FORTISBC UTILITIES UNDERTAKING NO. 12

HEARING DATE: December 13, 2012

TRANSCRIPT REFERENCE: Volume 3, Page 385, Line 25 to Page 386, Line 11

REQUESTOR: The Chairperson

WITNESS: Ms. Leeners

QUESTION: Provide a summary of how much capital was spent during the most recent Performance-Based Ratemaking ("PBR") period, that led to the depreciation variances shown in response to BCUC IR 2.182.4.

RESPONSE:

During the 2004-2009 PBR, capital spending in the year-to-year revenue requirements was set on a formula basis. The capital expenditure formulas had two main components for regular capital spending, approved by the Commission. Both regular capital components used a customer count metric as the driver. One component was based on new customer additions and the other was based on the total customer count. The difference between the rate base from the PBR formula-based capital spending and the rate base from actual capital spending increased over the six year PBR period as a result of the cumulative effect of FEI being more efficient with capital expenditures than the formula-based capital spending allowed each year. For the same reason, the differences between the PBR formula-driven depreciation expense and the actual depreciation expense increased over the six year period.

The approved expenditures in the table below were the result of a formula, and were not a forecast of actual expenditures.

Summary of FEI Non-CPCN Capital Expenditures ($000s)

	Actual	Formula	Variance
2009	$ 91,641	$ 90,327	$ 1,314
2008	90,084	100,654	$ (10,570)
2007	74,399	102,557	$ (28,158)
2006	85,204	98,945	$ (13,741)
2005	77,400	91,530	$ (14,130)
2004	71,422	86,265	$ (14,843)

Appendix D5

FORMULA EXCEL MODELS

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix D6

EFFICIENCY CARRY-OVER MECHANISM

EFFICIENCY CARRY-OVER MECHANISM

In this appendix FEI provides a description and an illustrative example of its proposed Efficiency Carry-Over Mechanism (ECM). The ECM is an important feature of the PBR to foster greater alignment of customer and Company interests throughout the PBR term and facilitate the achievement of longer-term efficiencies to produce enduring benefits. FEI's proposed ECM provides the same level of incentive to pursue efficiencies in the fifth year as it does in the first year, meaning rates coming out of the PBR should embed achievable efficiencies.

The ECM provides the incentive for FEI to pursue investments in efficiency in a manner similar to the way most non-regulated companies would evaluate investments in efficiency. By making the benefits of an efficiency initiative available for a pre-set period of time, as is the case with the proposed ECM, the Company has a reasonable (and consistent) opportunity to recover any costs that may be incurred to achieve the efficiency.

For FEI, the cost of the initial investment is calculated in the same manner as non-regulated companies. However, this is where the similarities in the analysis end. For utilities operating under a PBR and without an ECM, the value of the stream of savings required to pay back the Company's investment can only include those savings realized prior to the end of the term of the PBR. After the PBR Plan expires, the stream of savings is rebased into rates and is not available to help pay back the cost of the initial investment made by the Company. In the absence of the ECM, many initiatives that might otherwise be good candidates for investments in efficiency will likely not proceed. This is due to the inability of the Company to achieve payback from savings in the years following the investment (those beyond the term of the PBR) since the rates will be reduced in a regulatory proceeding when the PBR term expires. Thus, the lack of an ECM is detrimental to the long-run interests of customers since the utility's impetus to pursue efficiencies diminishes over the term.

The proposed ECM overcomes a significant part of the "artificial" end-of-term barrier by ensuring that the stream of savings resulting from an investment in efficiencies will be allocated to help repay the investment for five years regardless of how close the investment is to the end of the term of the PBR Plan. It does this by calculating the net benefits generated each year and sharing them equally between the customer and the Company for a rolling period of five years. This means efficiency gains in the second through fifth years of the PBR plan will generate the same benefits as those in the first year. This assurance of the continuing stream of savings provides the Company with the confidence to pursue efficiencies regardless of how few years remain in the term of the PBR Plan.

The savings from efficiencies can be calculated by determining the difference between the expected cost-of-service impact of the formula-based expenses under the PBR Plan with the actual cost-of-service impact from the actual level of those expenses. The difference represents the full savings from efficiency initiatives in the controllable expense categories without taking into account the temporary benefits or costs of revenue variances or flow-through expense variances. The incremental annual savings for the purposes of the ECM are calculated as the sum of:

1. Current year O&M savings relative to the current year formula-based O&M less cumulative O&M savings up to the prior year (relative to the prior year O&M formula amount); and
2. Plant additions savings (equal to current year formula-based plant additions less current year actual regular capital expenditures) multiplied by a rate base benefit factor of 15 percent. (The rate base benefit factor of 15 percent is explained after the illustrative example below.)

An example follows to illustrate how the ECM would operate.

The first two components of the example, sections (a) and (b) show an example of savings achieved in the incentivized controllable cost categories, i.e. O&M and capital expenditures.

Section (a) calculates the cumulative as well as the yearly incremental difference between O&M expenses allowed by the formula, and the actual expenses incurred; Lines 6 and 7 respectively.

Section (b) calculates the annual difference between the formula-based capital expenditures and actual capital expenditures, and presents the difference on Line 12. This annual capital expenditure savings is then multiplied by the rate base benefit factor of 15 percent, illustrated on Line 14.

The actual year-to-year expenditures for both O&M and capital are illustrative only and do not represent an estimate of what FEI may or may not be able to achieve.

Section (c) calculates the total annual revenue requirement benefits, and shows the 50:50 sharing calculations between customers and the shareholder for the term of the PBR (Lines 16 and 17). Lines 21 through 26 illustrate the incremental and cumulative efficiency benefits available for the term of the PBR, as well as for the period beyond the end of the PBR. Finally, on Line 31 the revenue impact from the end-of-plan benefits phase-out is shown for each year beyond the end of the PBR period. To be clear FEI would recover the amounts calculated from customers (assuming the value is positive) through a rate rider or amortization of a deferral account.

The example illustrates how the ECM benefits accrue during the term of the PBR, and continue to benefit both customers and the Company beyond the term of the PBR Plan. Customers receive benefits in two ways: (1) through the incentives in the PBR plan keeping O&M and capital spending low going in to the next revenue requirements application, and (2) through earnings sharing during the PBR term.

FortisBC Energy Inc.
2014 - 2018 PBR Plan
Illustrative Example of End-of-Term Efficiency Sharing Mechanism

Line No.	Particulars	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
1	**Revenue Requirements Benefits for EOT Efficiency Sharing**										
2											
3	**a).** O&M Benefits achieved ($ Millions)										
4	Allowed O&M per PBR formula (net of OH Capitalized)		$ 202.4	$ 206.3	$ 210.2	$ 214.5	$ 219.8				
5	Actual O&M (Illustrative)		200.0	201.3	203.2	208.5	210.8				
6	O&M Savings Achieved		2.4	5.0	7.0	6.0	9.0				
7	**Incremental O&M Savings over prior year cumulative savings**		**$ 2.4**	**$ 2.6**	**$ 2.0**	**$ (1.0)**	**$ 3.0**				
8											
9	**b).** Capital Expenditures Benefits achieved ($ Millions)										
10	Capital Expenditures allowed per PBR formula		$ 124.2	$ 127.8	$ 131.2	$ 134.0	$ 136.6				
11	Actual Capital Expenditures (Illustrative)		118.2	129.8	126.1	129.5	129.6				
12	Capital Expenditure Savings		$ 6.0	$ (2.0)	$ 5.1	$ 4.5	$ 7.0				
13	x Rate Base Benefit Factor		15%	15%	15%	15%	15%				
14	**Plant Additions Benefit**		**$ 0.9**	**$ (0.3)**	**$ 0.8**	**$ 0.7**	**$ 1.1**				
15											
16	**c).** Total Annual Revenue Requirement Benefits (Σ Lines 7+14)		$ 3.3	$ 2.3	$ 2.8	$ (0.3)	$ 4.1				
17	**x 50% Earnings Sharing**	50.00%	**$ 1.65**	**$ 1.15**	**$ 1.38**	**$ (0.16)**	**$ 2.03**				
18											
19											
20	Incremental Benefits Sharing for Phase-out ($ Millions)										
21	1st Year - 2014		$ 1.65	$ 1.65	$ 1.65	$ 1.65	$ 1.65				
22	2nd Year - 2015			1.15	1.15	1.15	1.15	$ 1.15			
23	3rd Year - 2016				1.38	1.38	1.38	1.38	$ 1.38		
24	4th Year - 2017					(0.16)	(0.16)	(0.16)	(0.16)	$ (0.16)	
25	5th Year - 2018						2.03	2.03	2.03	2.03	$ 2.03
26	Total Incremental Benefits Sharing		$ 1.65	$ 2.80	$ 4.18	$ 4.02	$ 6.05	$ 4.40	$ 3.25	$ 1.86	$ 2.03
27											
28	Rate adjustment permitted? (Y/N)		N	N	N	N	N	**Y**	**Y**	**Y**	**Y**
29											
30											
31	Revenues to FEI of ECM Benefits Phase-Out ($ Millions) - Increase / (Decrease)							**$ 4.40**	**$ 3.25**	**$ 1.86**	**$ 2.03**

Rate Base Benefit Factor

The Rate Base Benefit Factor is a calculation of the revenue requirements avoided by reductions in capital expenditures, expressed as a percentage of the initial capital expenditure. The revenue requirement caused by a particular capital expenditure is sometimes referred to as the capital carrying cost or rate base carrying cost. This discussion will use rate base carrying cost as the terminology. FEI is proposing a 15 percent Rate Base Benefit Factor as representative of the avoided revenue requirement or rate base carrying cost from reduced capital expenditures during the PBR term.

Capital expenditures pertain to fixed assets that are included in utility rate base, typically over the service life of the asset. The revenue requirement components associated with a particular capital expenditure are: the rate base return, depreciation expense and taxes. The rate base return can also be characterized as the return on investment. Depreciation expense is the return of investment. The possible items to include in the taxes category would be income taxes and property taxes. Income taxes are considered a rate base carrying cost because of the manner in which utility revenue requirements are calculated on a bottom-up basis to allow the utility to recover its interest costs on the debt-funded portion of an investment and provide it with a fair after-tax return on the equity funded portion. Property taxes fall into two categories and vary by asset type. FEI pays property taxes on certain types of assets (e.g. land, buildings, mains and service lines) based on assessed values and mill rates. FEI also pays a revenue-based property tax (called the 1 percent in Lieu tax) on revenues collected within municipal boundaries. Since all capital expenditures increase revenue requirements when they are added to rate base, they will likewise cause an increase in the 1 percent in Lieu Tax payable.

FEI has calculated the rate base carrying cost (excluding property taxes) of several asset types to provide support for the proposed 15 percent factor to be used as a Rate Base Benefit Factor. The asset types analyzed are (1) distribution mains for a low depreciation rate – low capital cost allowance (CCA) rate asset, (2) gas meters for a medium depreciation rate – low CCA rate asset, and (3) computer hardware for a high depreciation rate – high CCA rate asset. The rate base carrying cost for each of these categories has been calculated as the five-year levelized revenue requirement expressed as a percentage of the initial capital investment. These results are presented in the table below:

Table D6-1: Rate Base Carrying Cost by Asset Type

Asset Type	Depreciation & CCA Rates	Five-Year Levelized Rate Base Carrying Cost
Low Depreciation – Low CCA (Distribution Mains)	Depreciation rate – 1.48% CCA rate - 6%	9.6%
Medium Depreciation – Low CCA (Meters)	Depreciation rate – 7.89% CCA rate - 6%	17.3%
High Depreciation – High CCA (Computer Hardware)	Depreciation rate – 20% CCA rate - 55%	24.9%

FEI believes the proposed 15 percent value for the Rate Base Benefit Factor represents a reasonable weighting of the foregoing examples, which were picked to provide a reasonable range of results.

Appendix D7

SERVICE QUALITY INDICATORS

Service Quality Indicators

June 2013

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1. INTRODUCTION

Maintaining a high level of service quality is important to the long-term success of the Company. In support of this, and as in the 2004 Plan, FEI proposes a suite of Service Quality Indicators (SQIs) be established as part of this PBR Plan. The SQIs will serve to ensure that service quality to our customers is maintained at acceptable levels throughout the term of PBR Period.

In developing the proposed SQIs discussed in this report, FEI reviewed its experience with the existing indicators that have been in effect since the start of the 2004 Plan. In addition, FEI reviewed customer research, data and service quality indicators used by other utilities in Canada.

FEI proposes a suite of SQIs which builds on its experience, adding and eliminating SQIs where appropriate. In the following sections, the criteria for SQI selection, the SQI's history and development at FEI, as well as proposed updates and modifications are discussed.

As well, FEI has followed through on its commitment to evaluate customer service performance metrics during the first year of internal customer service operations. The Company made this commitment to ensure that customer service metrics meaningfully represent customer expectations and to ensure that they are reflective of the business process changes. The SQIs reported previously were designed to monitor the outsourcing arrangement. FEI has completed the customer service performance metrics evaluation with changes proposed to the customer service SQIs as discussed in this report. The resulting SQI metrics reflect a broad range of business processes that are important elements of the customer experience.

2. SERVICE QUALITY INDICATORS CRITERIA, BENCHMARKS AND HISTORY

2.1 *SERVICE QUALITY INDICATORS SELECTION CRITERIA*

In developing the proposed suite of Service Quality Indicators for the current application, the criteria used to establish the SQIs for the PBR plans in 1998 and 2004 were considered as FEI believes that the criteria are still appropriate. The criteria are presented in Table D5-1 below.

Table D5-1: Criteria for the design and selection of SQIs

ID	Criterion	Description
1	Value to customers	The indicator must represent a service or service attributes that customers value.
2	Controllable	Only those indicators over which the Company has control should be included. SQIs should not be linked to exogenous events over which the Company's employees actions have little or no influence.
3	Cost effective	The information collection activities associated with the indicator must be cost effective.
4	Simplicity and transparency	The indicator should be simple to administer and results should be easy to understand and interpret.
5	Traceable and Quantifiable	The indicators should have been previously tracked to ensure they are stable over time. The indicators must be quantifiable.
6	Flexibility	The indicators should allow sufficient flexibility to allow modifications, additions and deletions as required over time.

2.2 *CHOICE OF BENCHMARKS*

Benchmarks are reference points against which levels of service quality can be compared. The objective of SQIs is to ensure that the Company continues to provide an "acceptable level" of service at an "acceptable level" of cost to our customers. Therefore, in setting SQI benchmarks, it is necessary to consider whether customers are willing to pay for additional improvements in the indicators, as incremental costs for achieving further improvements increase as the limit of the indicator is approached. Benchmarks typically reflect either industry standards or the Company's performance over recent prior periods.

2.3 *HISTORY AND DEVELOPMENT OF SERVICE QUALITY INDICATORS AT FEI*

In the 1998 PBR Settlement, five service quality indicators were agreed to. The 2004 PBR Settlement continued with the use of three SQIs from the 1998 PBR Settlement, changed the status of two SQIs to directional indicators, and added eight new SQIs to assess the Company's performance.

FEI believes that an update of the 2004 approved SQIs is beneficial to customers. The proposed suite of SQIs includes:

- Refinement of two existing SQIs - Emergency response time, customer satisfaction survey;
- Continuation of four existing SQIs – Telephone service factor – emergency and non-emergency, billing index, meter exchange appointment activity;

- Addition of four new SQIs - First contact resolution, meter reading accuracy – the number of scheduled meters read, all injury frequency rate, and public contacts with pipelines; and
- Discontinuation of seven existing SQIs - Transmission reportable incidents, leaks per Km of distribution system mains, number of 3rd party distribution system incidents, accuracy of transportation meter measurement first report, number of customer complaints to BCUC, percent of transportation customer bills accurate, and number of prior period adjustments.

Table D5-2 following outlines the history and evolution of FEI's SQIs over the three eras (1998 PBR, 2004 PBR until 2012-2013 RRA and the proposed 2014 PBR). A detailed discussion of the proposed updates is presented in the following sections of this report.

Table D5-2: History and evolution of SQIs at FEI (1998 - 2014)

ID	Service Quality Indicator	1998 PBR	2004 PBR till 2013	Proposed 2014 PBR
1	Emergency response time	Included (Only coastal region)	Included (Interior region was added)	Revised definition of emergency response time
2	Telephone service factor - Emergency	Included (Only coastal region)	Included (Interior region was added)	Included
3	Telephone service factor – Non-emergency	Not available[1]	Included (for interior and coastal regions)	Included (Benchmark updated)
4	Transmission reportable incidents	Included	Included	Discontinued
5	Index of customer bills not meeting criteria	Not applicable	Included	Included (Renamed to Billing Index)
6	Percent of industrial customer bills accurate	Not applicable	Included	Discontinued
7	Meter exchange appointment activity	Not applicable	Included	Included (Benchmark updated)
8	Accuracy of transportation meter measurement first report	Not applicable	Included	Discontinued
9	Independent customer satisfaction survey	Not applicable	Included	Replaced with "customer satisfaction Index"
10	Number of customer complaints to BCUC	Not applicable	Included	Discontinued

[1] BC Hydro answered the majority of non-emergency inquiries prior to repatriation in 2002.

ID	Service Quality Indicator	1998 PBR	2004 PBR till 2013	Proposed 2014 PBR
11	Number of prior period adjustments	Not applicable	Included	Discontinued
12	Leaks per Km of distribution system mains	Included	Included (only as directional indicator)	Discontinued
13	Number of 3rd party distribution system incidents	Included	Included (only as directional indicator)	Discontinued
14	First contact resolution (FCR)	Not applicable	Not applicable	New customer service SQI
15	Meter reading accuracy - number of scheduled meters read	Not applicable	Not applicable	New meter reading SQI
16	All injury frequency rate	Not applicable	Not applicable	New safety SQI
17	Public contacts with pipelines	Not applicable	Not applicable	New customer SQI

3. PROPOSED SERVICE QUALITY INDICATORS AND BENCHMARKS

3.1 *OPERATIONAL SQIs*

3.1.1 Emergency Response Time

Emergency response time is included in the current set of SQIs and defined as the average length of time after notification for a qualified company representative to arrive on the scene of a gas emergency where the gas line has been struck or pulled or gas is blowing. The indicator measures the response time to these types of emergencies at any location on the FEI gas system both during and after working hours including weekends. The current benchmark was set at 21.1 minutes in 2003, based on the three year's previous history for Lower Mainland and Interior emergencies. The following table summarizes the recent historical emergency response time versus the benchmark.

Table D5-3: Recent historical results of emergency response time (in minutes)

2010	2011	2012	2010 - 2012 Average	Benchmark
22.5	23.4	23.8	23.2	21.1

The 2012 emergency response time was 23.8 minutes, 2.7 minutes above the benchmark and a slight increase from 2011 results of 23.4 minutes. Changes to the geographical mix of emergency hit line events, a decreasing number of events and the different response times historically experienced in these areas were the root cause of a higher overall weighted average response time.

Firstly, the overall number of hit line events has been on a declining trend with a 15 percent reduction in 2012 from 2011 levels. 2011 activity levels were down 10 percent from 2010. Secondly, the geographical distribution of the decreasing number of events has shifted over time. The Lower Mainland has typically experienced a higher percentage of emergency events and has historically lower response times due to the size of the available emergency response workforce. The decrease in the number of events overall, together with generally lower response times than Interior locations, have contributed to a higher weighted average response time. Also, emergency response time to Fraser Valley hit line events, proportionally the area with the most number of events, has increased year over year by 1.5 minutes, primarily for day time events. Traffic congestion, roadwork, and resultant travel times have been the root cause of the increase. The Northern Region, Prince George and Quesnel primarily, in contrast to the rest of the Province, experienced a 20 percent increase in hit line emergency activity in 2012. The higher response time for this outlying area (26 minutes) and the higher weighting of this geographical area in the total mix contributed to the higher overall emergency response time observed.

At FEI, responding to gas emergencies, such as a pulled or struck gas main or blowing gas situation, is of the highest priority. FEI believes that its response time to these types of gas emergencies is appropriate. Therefore, no changes are required to our emergency response resources and emergency management and dispatching process.

FEI believes, however, that the metric as defined currently is too narrow in that not all emergency events are considered in the response time. The metric is not readily comparable to other Canadian Gas Association (CGA) member equivalent metrics. Also, emergency response times in all geographical areas are not equal (due to the size of emergency response footprints) and changes to activity levels in each geographical area impact and distort the overall weighted average response time when using a data set of now less than 1,000 hit line events annually.

The problems with the current emergency response metric can be eliminated by using a more comprehensive and widely accepted industry emergency response metric. This change will more accurately reflect a performance metric comparable to other Canadian gas utilities. Inclusion of a broader scope of emergencies will measure the response time on a considerably higher number of events and mitigate the variability created by changes in the geographic mix that distort the existing narrowly defined emergency metric.

The CGA definition of emergency events is broader and includes gas odour calls, carbon monoxide calls, house fires, hit lines, etc. (approximately 24,000 events annually for FEI). CGA emergency response time is defined as “percentage of emergency events responded to within one hour” and calculated as:

$$\frac{\text{Number of emergency calls responded to within one hour}}{\text{Total number of emergency calls in the year}}$$

Table D5-4 following summarizes FEI's 2010 - 2012 emergency activity levels (# of calls), average emergency response times (minutes) for the various types of emergencies, the number of calls greater than 60 minutes, and the overall percentage of emergency response times 60 minutes or less. When all types of emergencies are considered (between 21,000 and 25,000 activities annually), the average annual response time for the 2010 - 2012 period was 20.3 minutes and the percentage of responses 60 minutes or less averaged 97.7 percent, with very little variation year over year.

Table D5-4: Summary of FEI emergency activity levels and average response time (in minutes)

		CGA type Emergency[2]	Number of calls over one hour	Percent of response one hour or less
2010 to 2012	Number of calls	70,775	1,665	97.7%
	Average response time	20.3		
2012	Number of calls	21,686	566	97.4%
	Average response time	19.7		
2011	Number of calls	24,396	523	97.9%
	Average response time	19.7		
2010	Number of calls	24,693	576	97.7%
	Average response time	21.4		

To ensure an appropriate response time, FEI's service level was compared with other Canadian gas utilities. In the most recent CGA survey conducted in 2008, the comparable service level ranged from 88 percent to 99 percent, with an industry average near 95 percent. As presented in Table D5-4 above, the Company's service level for emergency calls is higher than the industry average (97.7 percent versus 95 percent). This positions the Company in the top quartile of CGA member companies based on the 2008 survey.

FEI proposes a benchmark of 95 percent, so that the overall response time is appropriate, at or above the industry average and in the top quartile of CGA member companies. FEI believes that adopting the broader definition of emergencies and the CGA measure and benchmark for emergency response time reflects the appropriate level of service for FEI's gas customers.

3.1.2 Meter Exchange Appointment Activity

This indicator tracks the percentage of appointments met for meter exchanges (excluding industrial meter exchanges). The meter exchanges are required to be done under regulations from Measurement Canada and are generally completed in less than an hour including travel

[2] Following items are included in CGA emergency: Gas odour upstream and downstream, gas odour – industrial, gas odour – other, fires and explosion, CO investigation, mains hit lines, services hit lines, meter/station.

time. The gas is shut off, the in-service meter is exchanged for a new meter, the gas is turned on and the technician locates and relights the customer's appliances. The appointment is necessary as the technician requires access to the inside of the premise to perform the relights to the gas appliances.

The following table summarizes the recent historical results from 2010 – 2012.

Table D5-5: Recent historical results for meter exchange appointments met and benchmarks

2010	2011	2012	2010 - 2012 Average	Current benchmark	Proposed benchmark
94.2%	96.5%	96.5%	95.7%	92.2%	95.0%

FEI values customers' time and strives to meet customers' expectations with regard to commitments it makes to perform scheduled work at their premises.

FEI proposes to maintain the existing meter exchange activity metric and to increase the current benchmark[3] from 92.2 percent to 95.0 percent. The new benchmark of 95.0 percent reflects the average of the past three years' actual results. Although the number of meter exchanges will be increasing beginning in 2014 as a result of adopting new Measurement Canada compliance sampling regulations, FEI believes it can maintain the current customer service level.

3.2 *CUSTOMER SERVICE SQIS*

3.2.1 Telephone Service Factor (TSF)

Telephone service factor (TSF) is a measurement of the percentage of calls answered within a defined window of time and was previously called "Speed of Answer". FEI believes that TSF is an appropriate contact centre metric as it balances costs with service quality. Historically reported has been the speed of answer for both emergency and non-emergency calls for FEU. Non-emergency calls include those related to bill inquiries, service applications and calls general in nature.

Following is a summary of the recent historical results for FEU, the established and proposed benchmarks. Except for a minor variance in 2011 for Non-Emergency Calls, the results over the three year period exceeded the established benchmark.

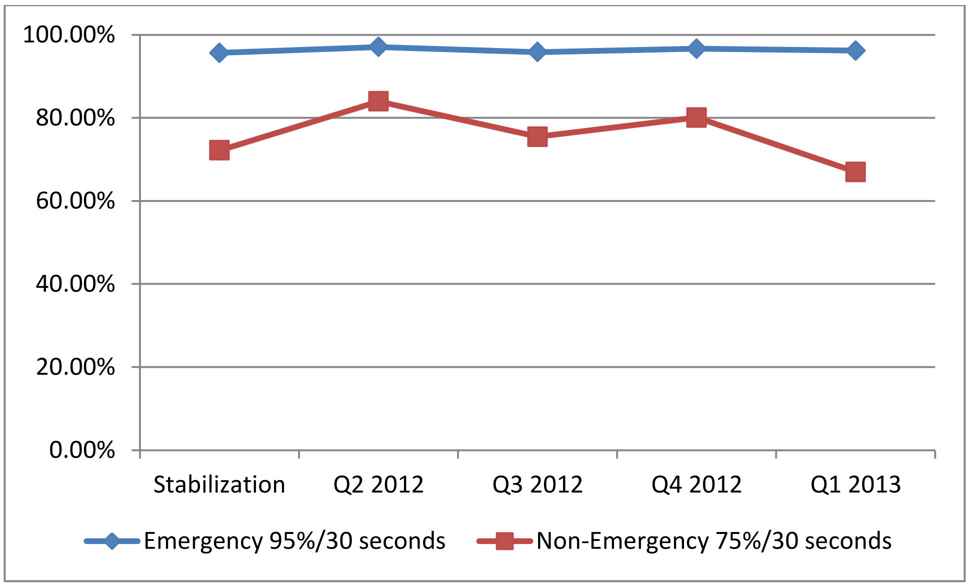
Table D5-6: Recent historical results for Telephone Service Factor

Type of Call	2010	2011	2012	Current benchmark	Proposed benchmark
Emergency	99.2	96.5%	96.5%	92.2%	95.0%
Non Emergency	77.2	74.7	76.2	75.0%	70.0%

[3] Reference to current benchmark is to that established for the 2004 – 2009 PBR Plan.

In 2012, after the implementation of the Customer Care Enhancement project to in-source the customer care and billing functions, the average service levels achieved were 96 percent for emergency calls and 76 percent for non-emergency calls, with both measures meeting the established benchmark. Quarterly results for 2012 and the first quarter of 2013 are shown in Figure D5-1 below.

Figure D5-1: TSF Results



Service levels for non emergency calls were challenged in the first quarter of 2013 due to high call volumes and relatively low staffing levels. Two new classes of customer service representatives were brought on board in February and March to address these issues going forward. To improve customer service response time, the Company also implemented a call back feature where customers could opt to request to keep their place in line and not wait on hold, but instead be called back when they are the next in line. In 2012, 21,659 customers utilized this service during high volume times.

FEI recommends continuing to report on TSF, retaining the existing benchmark for emergency calls and aligning the benchmark for non-emergency calls to that which has been in place for FortisBC's electric operations for a number of years. FEI proposes the following benchmarks:

- Emergency Calls: 95 percent of calls answered in 30 seconds or less.
- Non-Emergency Calls: 70 percent of calls answered in 30 seconds or less.

FEI believes that these service levels reflect an appropriate balance between cost and service levels and allows for a better comparison between its gas and electric operations. Please also see Section C3.5: Customer Service for a discussion on the forecast change in customers service levels for non-emergency calls.

3.2.2 First Contact Resolution (FCR)

First contact resolution (FCR) is an area of focus for FEI as research conducted suggests that it is the single most important driver of customer satisfaction. By improving FCR, the Company can effectively drive productivity and efficiency in the customer service department.

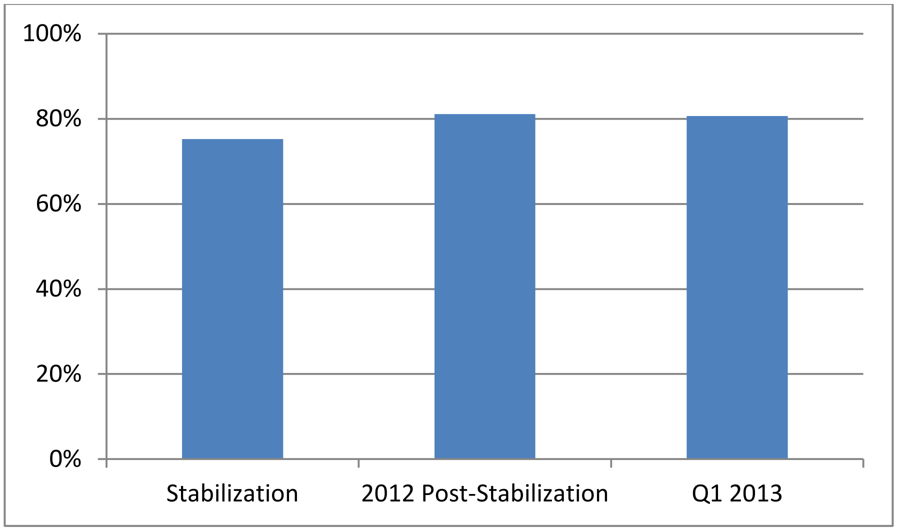
Since 1996, the Service Quality Measurement (SQM) group has been a leading North American call center industry research firm expert for improving organizations' FCR, operating costs, employee and customer satisfaction. SQM benchmarks over 450 leading international call centers on an annual basis and has been conducting FCR and customer satisfaction benchmarking studies since its incorporation. SQM evaluates over 450 leading North American call centers each year for such companies as American Express, FedEx, Marriott, Sears, Canadian Tire, U.S. Bank, Wells Fargo, Rogers, Capital One, CitiFinancial, Scotiabank, Discovercard, and Blue Cross. Their research indicates that for every one percent improvement in FCR, there is typically a one percent improvement in customer satisfaction (top box response), all else being equal.[4] Their research supports that FCR is the metric with the highest correlation to customer satisfaction. This conclusion is affirmed through statistical analysis of FortisBC's own electric customer service survey data.

FEI believes that the simplest and most effective way to evaluate FCR is to ask the customer their opinion as to whether or not their issue was resolved on the first contact. In order to gain customer feedback on this topic, FEI uses SQM to contact customers who have recently had an interaction with the Company. Since spring 2012, an average of 400 customers per month have been contacted by SQM, who ask each customer a number of questions including whether or not their question or issue was resolved. Starting in May 2012, the methodology switched from live agent calls to an automated IVR approach and the number of customers contacted increased to a targeted 1,355 calls per month. The switch reduces the margin of error and facilitates individual service representative reporting. Completed surveys are automatically added to an aggregate data set to facilitate the calculation of various metrics including FCR.

In 2012, an average score of 78 percent for FCR was achieved for FEU, which was above the industry average and within the first quartile. These results are considered a significant achievement given that it was the first year of operations for the new customer service center. The results are as follows:

[4] SQM Group, reference available at www.sqmgroup.com/first-call-resolution-level-1

Figure D5-2: First Contact Resolution



SQM's extensive research activity permits FEI to benchmark its contact centre services with that of other companies. The following table compares results for FEU to SQM's 2012 FCR benchmark results.

Table D5-7: FEU and Benchmark FCR Results[5]

FEU	Average Call Center	Average Energy Call Center	1st Quartile	2nd Quartile	3rd Quartile	4th Quartile
78%	70%	71%	77% +	76% - 71%	70% - 66%	65% - 0%

FEI proposes the adoption of FCR as a service quality indicator as it is an important measure of service quality. A benchmark of 78 percent is proposed, positioning the Company above the industry average and consistent with the 78 percent achieved by the Company in its first year of operations for its call centers.

3.2.3 Billing Index

This indicator is designed to track the effectiveness of the Company's billing system and is measured as the percent of customer bills produced meeting performance criteria. This indicator has been renamed from the previous name of "Percent of Customer Bills Produced Meeting Performance Criteria" to better represent its focus. Similar to the 2004 PBR, the billing index is a composite index with three components: billing completion (percent of accounts billed within two days of billing due date), billing timeliness (percent of invoices delivered to Canada Post within two days of file creation) and billing accuracy (percent of bills without a production issue). The differential between the benchmark and the actual for each is then divided by three to determine the billing index. The objective is to achieve a score of five or less. The relevant formulas and benchmarks for the three sub-measures are presented below.

5 SQM QTR 4 2012 Tracking Results, FortisBC Natural Gas Report, January 14, 2012, page 5 and 32.

Table D5-8: The Benchmarks and Formulas for Calculation of Billing Index SQI

Billing sub-measure	Percent achieved (PA)	Adjustment	Result
Percentage of bills accurate based upon input data	99.9%	* See formula below	5.0
Percentage of bills delivered to Canada Post within two days of date that the statement file is created	95%	(100% - PA)*100	5.0
Percentage of customers billed within two business days of the scheduled billing date	95%	(100% - PA)*100	5.0
Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			5.0

* IF [PA ≥ 99.9%, 5000 * (1 - PA), 100 * (1.05 - PA)]

Following is a summary of the recent historical billing-index calculation versus the benchmark.

Table D5-9: Recent historical results for billing-index

2010	2011	2012	Benchmark
2.40	0.24	3.01	5

FEI proposes to retain the current benchmark of 5.

3.2.4 Meter Reading Accuracy – number of scheduled meters that were read

The results for 2012 show a steady pace of completed reads with results in the first half of the year at 95 percent, with quarter three at 94 percent, and quarter four at 93 percent. FEI had expected a decline in service levels towards the end of the year as a result of transitioning from the previous meter reading contractor to the current one.

In 2013, in order to address customer concerns related to billing accuracy, the Company has moved to monthly meter reading, instead of bi-monthly which has been in place in the past. The Company will now read meters monthly (approximately 970,000 meters), including the majority of customer move reads and special reads required in response to billing inquiries (estimated at 100,000 annually).

The benchmark for this SQI is 95 percent, which is built into the new contract for meter reading.

3.3 *INFORMATIONAL SQIS*

Indicators which are not as closely related to actual service quality but are useful for assessing performance, will be reported as informational indicators. FEI proposes the following three informational indicators.

3.3.1 All Injury Frequency Rate

FEI is committed to continual improvement of corporate safety performance and will report employee safety performance as part of the Company's SQI profile using the metric All Injury Frequency Rate (AIFR). The reduction of work stoppage and efficiency losses as a result of safety incident reduction will promote productivity enhancements across the Company.

The AIFR is a comprehensive safety performance indicator based on lost time injuries (LTI) plus medical treatment injuries (MT) per 200,000 hours worked (approximately injuries per 100 workers). LTIs are injuries that result in one or more days missed from work. MTs are injuries where medical treatment was given or prescribed beyond medical aid and observation, and no lost time was involved.

The following formula is used:

$$\text{All Injury Frequency Rate} = \frac{(\text{Number of LTD + MT}) \times 200{,}000 \text{ hours}}{\text{Exposure Hours}^{6}}$$

Following is a summary of the FEU's AIFR annual and three year rolling average results from 2010 to 2012.

Table D5-10: 2010 – 2012 AIFR Historical Performance

Year	Lost Time Injuries	Medical Treatments	Annual	Three Year Rolling Average[7]
2010	16	16	2.66	2.32
2011	9	14	1.67	2.27
2012	15	14	1.91	2.08

FEI proposes to include this metric as an informational service quality indicator with no benchmark as the results are to be considered informational in nature.

3.3.2 Public Contacts with Pipelines

FEI recognizes the importance of public safety. A key area of public safety is contact with buried pipelines. To measure performance in this area, FEI proposes the use of the metric Public Contacts with Pipelines, which reflects the number of line damages per 1,000 BC One Calls received. The Company places significant attention on educating the public of the risk associated with gas line contact. This SQI will measure the overall effectiveness of the public's

[6] Exposure hours reflect actual hours worked excluding time off for vacation, statutory holidays, sickness, etc.
[7] Three year rolling average calculated by taking the average of last three years' annual results (i.e. 2012 three year average is calculated by taking annual results for 2010 – 2012 (2.66 + 1.67 + 1.91) and dividing by 3 = 2.08)

awareness to minimize damage to the gas system, which will reduce risk to public safety and service interruptions for customers.

Following is a summary of the FEU's Public Contacts with Pipelines annual and three year rolling average results from 2010 to 2012.

Table D5-11: 2010 – 2012 Public Contacts with Pipelines

Year	Annual	Three Year Rolling Average[8]
2010	19	22
2011	16	18
2012	13	16

FEI proposes to include this metric as an informational service quality indicator with no benchmark as the results are to be considered informational in nature.

3.3.3 Customer Satisfaction Index (CSI)

Introduced in 2002, the customer satisfaction metric has been measured using four customer satisfaction surveys - Residential (75 percent), Builder & Developer (10 percent) Small Commercial (5 percent) and Large Commercial (10 percent), with each component assigned individual weightings.[9] This customer satisfaction model (CSat) was designed to provide feedback regarding customer satisfaction and to ensure that service quality is maintained at acceptable levels during the applicable settlement periods.

Starting in 2013, a replacement method for measuring customer satisfaction, the Customer Satisfaction Index (CSI) has become the measurement for assessing overall customer satisfaction for the Company. The CSI score provides more timely feedback and ensures the Company is using the same strategy to survey both residential and mass market commercial customers. In addition to covering service touch points such as contact centres and field services, it also measures how the customers view the Company.

The CSI survey is conducted quarterly involving 600 telephone interviews with customers. The research vendor uses quota sampling to ensure 500 interviews are residential customers, and 100 are mass market commercial customers (Rate Schedule 2). The index is based on responses to several questions employing a 10 point scale (i.e., top four box answers 7-10). Index contributors include: (1) overall satisfaction with natural gas service from FortisBC; (2) satisfaction with the accuracy of meter reading; (3) satisfaction with energy conservation information; (4) overall satisfaction with the contact centre; and (5) overall satisfaction with field services.

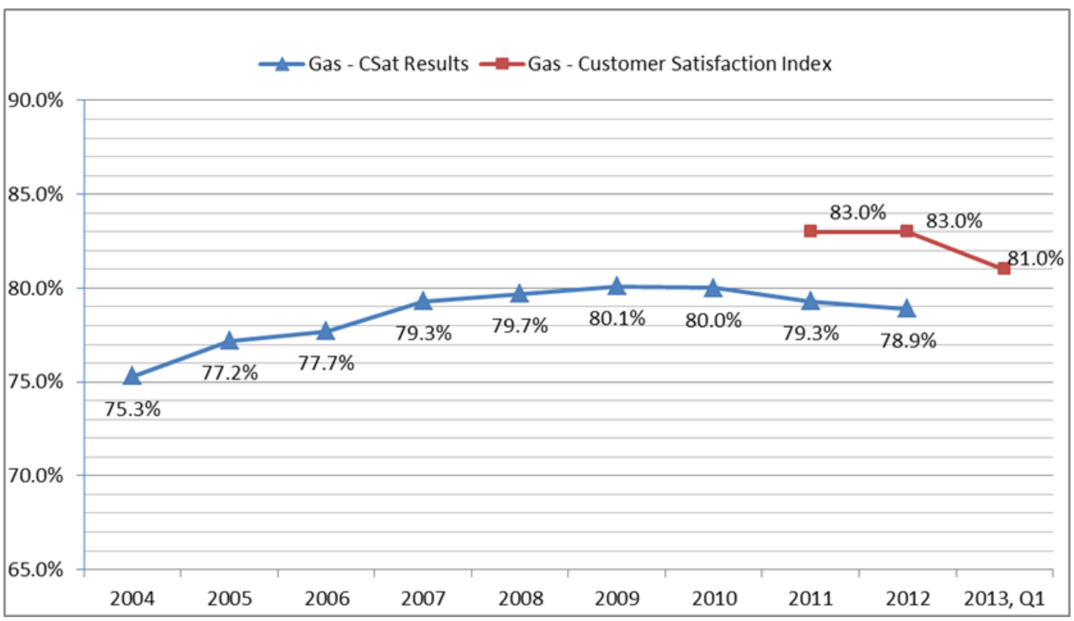
[8] Three year rolling average calculated by taking the average of last three years' annual results (i.e. 2012 three year average is calculated by taking annual results for 2010 – 2012 (19 + 16 + 13) and dividing by 3 = 16)
[9] An amendment was made in 2004 to add an additional customer class (Small Commercial).

The decision to replace the CSat with the CSI is based on a number of considerations:

- Historical CSat studies mix experience and perception based questions, so customers may be asked to rate a service they never experienced. The CSI focuses on recent customer transactions to ensure feedback measures service quality more accurately.
- The CSI surveys are shorter, resulting in fewer customer complaints, higher completion rates, and lower survey costs.
- The CSI asks the same questions to both residential and mass market commercial customers, making the results comparable. The CSat studies used different methods to calculate overall satisfaction and framed questions differently.
- The CSI studies facilitate correlation analysis, allowing the Company to better evaluate shifting customer priorities.

The graph below compares results from the historical CSat model since 2004, with CSI scores since 2011 through to Q1 2013.

Figure D5-3: CSAT / CSI Results



In 2012, the CSI score for FEU as shown on the graph was stable. In Q1 2013, the total CSI score fell by three points to 8.1[10], still within the margin of error.[11] This dip was primarily

[10] The equivalent CSat score is 81percent for a CSI score of 8.1.

associated with (1) a drop in customer scores for the "Accuracy of meter reading" which fell to 7.6 from the previous quarter's 8.1; and (2) a 0.5 drop in, "Satisfaction with field services" which fell to 8.6 from 9.1.

The field service metric contributes 25 percent of the overall CSI, so performance changes have a noticeable influence on the index score. Due to the limited number of field service interactions in the sample, the attribute is subject to a substantial margin of error (±0.6). The actual field service score could be as high as 9.2 or as low as 8. However, complementary research suggests field service quality is in fact stable. The Company will continue to monitor CSI results and address service issues if appropriate.

FEI proposes to include this metric as an informational service quality indicator. Consistent with how this measure has been used in past PBRs, FEI proposes that no performance threshold be established for this SQI. Results are to be considered informational in nature and consideration should be given to external factors that can influence customer satisfaction scores. This includes the price of natural gas which is an exogenous factor and can have an adverse influence on customer satisfaction.

Table D5-12 following summarizes FEI's proposed service quality indicators along with the proposed benchmarks. The last three indicators listed in the table are Informational only with their performance assessed by comparing to previous years' performance, recognizing the impact of events beyond FEI's control.

[11] Based on the sample of 600 customers and the underlying population size, the CSI decline from 8.4 to 8.1 is considered "not statistically significant" because the dip falls within the calculated margin of error of ± 0.4, at the 95% confidence level. As such, sampling error cannot be ruled out as the possible cause of the decline.

Table D5-12: Summary of Proposed Service Quality Indicators

Service Quality Indicator	Benchmark
Emergency Response Time	95% of calls responded to within one hour (CGA definition)
Meter Exchange Appointment Activity	95%
Telephone Service Factor (Emergency)	95% of calls answered in 30 seconds or less
Telephone Service Factor (Non Emergency)	70% of calls answered in 30 seconds or less
First Contact Resolution	78%
Billing Index – Mass Market	5
Meter Reading Accuracy - number of scheduled meters that were read	95%
All Injury Frequency Rate	Informational indicator
Public Contacts with Pipelines	Informational indicator
Customer Satisfaction Index	Informational indicator

4. DISCONTINUED SQIS

Given the proposed suite of SQIs, FEI believes that some of the existing metrics currently reported provide limited value going forward. Following is a summary of the SQIs being discontinued.

Transmission Reportable Incidents

This indicator tracked the number of reportable incidents to outside agencies (i.e. Oil and Gas Commission, WorkSafeBC, etc.) for the transmission system and was intended to be an indicator of the integrity of the transmission system.

Leaks per KM of Distribution System Mains

This directional indicator was intended to be one indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system was surveyed for leaks. The number of leaks varied from year to year, more as a result of the condition of the pipe being surveyed in the given year, than the quality of the maintenance program.

Number of 3rd Party Distribution System Incidents

This directional indicator tracked the number of third party damages to gas system infrastructure and included excavation damage to underground pipe, as well as damages to above ground facilities such as meter sets and stations. In its proposed suite of SQIs, the Company has a similar metric called “Public Contacts with Pipelines” which tracks the number of third party hits (below ground) per 1,000 BC One Call tickets.

Accuracy of Transportation Meter Measurement First Report

This service quality indicator tracked the percent of time when the deviation is less than 10 percent between the preliminary billing estimate that is first reported to an industrial customer, compared to the final amount that is billed to the customer. This SQI for Industrial Meter Measurement contained both an accuracy measure (percent deviation) and a frequency measure, applied to both daily and monthly groups on a gigajoule weighted basis. Customers who did not provide the Company with a metering phone line were not included in this measure.

Number of Customer Complaints to BCUC

This indicator tracked the number of customer complaints submitted to the Commission that the Commission then requests, either by Commission Letter or by a Complaint/Inquiry Record, that FEI provides a written response.

Percent of Industrial Customer Bills Accurate

This service quality indicator tracked the accuracy of billing for Industrial customers.

Number of Prior Period Adjustments

This customer satisfaction indicator tracked the number of prior period adjustments for Industrial Transportation Service customers. A prior period adjustment consisted of a billing inaccuracy that was identified after a bill had been issued. If this occurred, the bill was corrected.

5. ANNUAL REVIEW PROCESS

At the Annual Review workshop, year to date SQI actuals along with projected year end results will be presented along with commentary on the results. Discussion of the SQI’s performance will serve to provide a better understanding of any issues affecting the Company’s ability to meet the established benchmarks.

Appendix D8

REFERENCED ACADEMIC PAPERS

Appendix D8-1

NEGOTIATED SETTLEMENTS AND THE NATIONAL ENERGY BOARD IN CANADA

Joseph Doucet and Stephen Littlechild,
January 15, 2009

Negotiated Settlements and the National Energy Board in Canada[a]

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Stephen Littlechild[c]

15 January 2009

JEL Classification: L51 Economics of regulation, L97 Utilities general, L95 Gas utilities, pipelines, water utilities.

Key words: negotiated settlements, regulation, innovation.

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Negotiated Settlements and the National Energy Board in Canada

Abstract

In Canada, settlements between oil and gas pipelines and users have largely superseded the litigation of major pipeline toll cases since 1995. Quantitatively, from the first half to the second half of the period 1985-2007 the average number of pipeline toll hearing days in Canada fell by three-quarters. On average, settlements are for more than twice as long as litigated outcomes and have cut regulatory processing times by about one third for gas pipelines and by about two thirds for oil pipelines, with the result that regulatory processing times per effective toll-year have fallen to 13% and 27% of previous levels. Qualitatively, settlements have been used to determine prices, operating and capital cost projections, return on equity, service quality improvements, risk-sharing investments and information requirements. They were the vehicle by which multi-year incentive agreements developed rapidly for all pipelines. They have also been used to introduce light-handed regulation. They have provided a mechanism for fruitful collaboration between pipelines and their customers and have changed attitudes in the industry. Two key actions of the National Energy Board have facilitated settlements: its generic cost of capital decision that removes the market power of the pipeline and enables effective negotiation with users, and its willingness to judge a settlement by the reasonableness of the process leading up to it instead of imposing the Board's own values on the outcome. In law and economics terms, these actions established and clarified the property rights that made negotiated settlement possible.

1. Introduction

The regulation of public utilities in North America conventionally uses a hearing and decision process, sometimes referred to as litigation. Negotiated settlements between public utilities and their customers or users are alternative or complementary to this process. Legal scholars and practitioners have long explained the importance of settlements in coping with the regulatory load and avoiding delay, in saving time and money, and in reducing uncertainty.

The law and economics literature would perhaps find it obvious that settlements are preferred to litigation, because they can achieve anything that litigation can achieve at lower cost, unless the parties had particularly disparate expectations about the outcome of litigation.[1] However, this rationale is unpersuasive in the case of utility regulation, where it is not clear that there is a significant difference between the costs of litigation and settlement, where the parties do not appear to have distinctive expectations or risk aversion, and where the decisions of the regulator may be relatively predictable. Given

[1] "There is more scope for settlement when litigation is costly, negotiations are inexpensive, and the disputants are pessimistic about trial outcomes…. Risk aversion … presumably increases the probability of a settlement. " Cooter and Rubinfeld (1989) p. 1076

the long tradition of utility regulation by litigation, the challenge is to explain why and how settlements have emerged at all.

More recently it is suggested that settlements better serve the needs of the parties, allow greater flexibility and innovation, and can achieve results that lie beyond traditional regulatory authority.[2] Economic research is now confirming this perception.[3] The US Federal Energy Regulatory Commission (FERC) and the Florida Public Services Commission have dealt with a high proportion of regulatory cases by means of settlements. These settlements are not simply a more efficient way of doing the same thing as traditional regulation. Rather, they involve considerable innovation, notably the introduction of price caps, rate moratoria and (at FERC) must-file provisions, and (in Florida) the development of revenue sharing schemes and other incentive mechanisms, that would otherwise have been impossible or at least unlikely. That is, the main purpose of these settlements is not to reduce the cost or risk of litigation or to resolve conflicting expectations, but to secure mutually preferred outcomes that the regulator could not or would not otherwise deliver.

The present paper reinforces this argument by examining the negotiated settlements that have recently been prominent in the Canadian energy sector.[4] It extends previous research in various respects: a) it documents quantitatively the growth of settlements and their impact on hearings and processing of applications; b) it describes how settlements evolved and the form they have taken; c) it shows how the regulatory framework first discouraged then encouraged the development of settlements; and d) it indicates how settlements have generally led to more innovative outcomes in this jurisdiction than at FERC or even Florida notably in one case effecting a transition from active to light-handed regulation. The concluding remarks briefly consider the case of non-participating and contesting parties, and note some possibilities for further research.

2. Institutional Context

2.1 The National Energy Board, the pipelines and users

The National Energy Board (NEB or the Board) is an independent federal regulatory agency established under the National Energy Board Act in 1959.[5] In the current budget year (2008-2009) the Board has a staff of approximately 350 and an annual budget of $47 million (Canadian).[6]

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[2] The various contributions to the economic and legal literature are summarized in Doucet and Littlechild (2006a).
[3] Wang (2004), Littlechild (2003, 2009a,b).
[4] See accounts by two recent chairmen of the National Energy Board (Vollman 1996, Priddle 1997, 1999) and further discussion and analysis by Mansell and Church (1995), Miller (1999), Schultz (1999).
[5] For more information on the NEB and the Act, and for other NEB references, see the National Energy Board web site http://www.neb-one.gc.ca. NEB decisions are available electronically on this site. The NEB in Canada is roughly equivalent to the FERC in the US.
[6] Treasury Board of Canada 2008-2009 Reports on Plans and Priorities, available at http://www.tbs-sct.gc.ca/rpp/2008-2009/inst/enr/enrtb-eng.asp .

Active economic regulation of pipeline tolls began in the 1970s. The eight pipelines that are the focus of this study are those Group 1 pipelines that are subject to more active regulation by the Board.[7] Their tolls and tariffs have traditionally been determined through a litigated process involving hearings. In contrast, Group 2 pipelines (plus 4 of the smaller Group 1 pipelines) have been regulated on a “complaint basis” since at least 1985. These pipelines submit tolls and tariffs to the Board, which are automatically accepted unless an objection is filed by a shipper or stakeholder in which case a hearing may take place.

In addition to the pipelines the other interested parties in regulatory issues include producers, shippers and consumers. There are a large number of producers of oil and gas in Canada, the overwhelming majority of which are private. Shippers, who are sometimes producers and sometimes third parties, contract with pipelines for transportation of the oil and natural gas. The relevant consumers include large industrials, local distribution companies and refineries.

2.2 The work of the Board

For the most part, the Board does not initiate cases but responds to “applications” by regulated entities and other parties – for example, for permission to build pipelines and power lines, for changes to pipeline tolls and tariffs, for energy export licences and for oil and gas development in Frontier areas. In the most important cases, the Board will hold oral public hearings in which applicants and interested parties can participate. This is the traditional litigated process applied to utility regulation in North America.[8]

In the case of pipeline tolls and tariffs, which are the focus of the present paper, there would traditionally be a periodic toll hearing for each pipeline where several contentious issues were considered at one time. This was often annually or biennially for the major gas pipelines although tolls for some of the major oil pipelines sometimes ran for several years.

Table 1 summarizes applications dealt with by the Board over the period 1985-2007 in the four broad categories corresponding to the Board’s responsibilities. Although slightly incomplete, it presents a clear picture in important respects. The Board deals with over 500 applications annually, slightly more nowadays than in the earlier years. Around three quarters of the recorded applications are for energy exports (mostly short-term natural gas export orders). Applications relating to pipeline tolls and tariffs account for only about 2 per cent of all applications (or at most 4 per cent allowing for data omissions in Table 1).

In practice, the vast majority of applications to the Board are handled without a hearing. However, there is a significant difference by category of application. Table 2 shows the

[7] They comprise 3 oil pipelines: Enbridge (formerly Interprovincial or IPL), Trans Mountain and Trans-Northern, and 5 gas pipelines: TransCanada PipeLines (TCPL), Westcoast, Gazoduc Trans Québec & Maritimes (TQM), Maritimes and North-East (M&NP), and Alliance. The last two commenced operation in 2000.

[8] In other cases where there is sufficient public interest, the Board will instigate a public consultation process and invite written comments before making its decision. In yet other cases, applications and routine filings are dealt with administratively by letter or simply by acknowledgement.

number of hearings and hearing days at the Board. In total, only about 2 per cent of all applications (261/12,390) have gone to hearing. In the toll category, in contrast, the proportion was about one third (69/230) of those applications recorded in Table 1. In consequence, toll hearings accounted for over one quarter (69/261) of all hearings during this period.

Hearings are time-consuming. During the period as a whole, the average duration over all categories was 8 days.[9] Toll hearings have typically lasted about twice as long as non-toll hearings: an average of 12.7 days compared to 6.4 days. Taken with the higher proportion of toll applications that go to hearing, this means that toll applications accounted for over 40 percent (877/2099) of all hearing days during this period.

Thus, although pipeline toll applications constitute only a very small fraction of the total number of applications to the Board, they are much more significant than other categories in terms of the attention they require, at least in terms of the number of hearings and the time these hearings take.

[9] This is in addition to the time required by all parties to request, provide and query information and to prepare the case, and the time subsequently taken by the Board to compile and issue its report, and any time spent in appealing the Board’s decision to the Federal Court of Appeal or the Supreme Court of Canada.

Table 1: Applications to the National Energy Board, 1985-2007

Category **Year**	**Construction of Pipelines and Power Lines**	**Pipeline Tolls and Tariffs+**	**Energy Exports**	**Frontier Activities**	**Total applications**
1985	62	5	207	n/a	274
1986	65	4	339	n/a	408
1987	64	6	356	n/a	426
1988	79	4	371	n/a	454
1989	60	5	495	n/a	560
1990	72	8	470	n/a	550
1991	70	6	457	n/a	533
1992	89	4	440	4	533
1993	111	7	520	4	642
1994	115	3	516	3	637
1995	78	9	584	66	737
1996	82	7	*217	15	[321]
1997	94	4	*236	92	[426]
1998	111	2	*239	**	[352]
1999	151	1	*245	93	[490]
2000	129	3	571	142	845
2001	92	11	335	63	501
2002	181	15	548	96	840
2003	184	18	411	100	713
2004	100	27	363	49	539
2005	104	33	423	53	613
2006	33	35	382	48	498
2007	53	13	378	50	494
Total	2,179	230	[9,103]	[878]	[12,390]
Annual Average	95	10	[396]	***73	[539]

Source: NEB Annual Reports supplemented by information from NEB staff
+ Until 2000 the figures for pipeline toll and tariff applications refer only to applications that were considered in a hearing or other public consultation process. They exclude the more routine filings that are included in the data for the other three categories.
* Information not available with respect to short term exports of oil, natural gas, butane and propane
** Information not available
*** Average since 1995 excluding 1998
n/a Not applicable

Table 2: Number of hearings and hearing days at the NEB, 1985-2007

	Pipeline tolls		Non-toll categories		All categories	
Year	**Number of Public Hearings Initiated**	**Total Hearing Days**	**Number of Public Hearings Initiated**	**Total Hearing Days**	**Number of Public Hearings Initiated**	**Total Hearing Days**
1985	4	38	14	128	18	166
1986	5	96	6	82	11	178
1987	5	162	10	51	15	213
1988	3	68	10	57	13	125
1989	4	91	9	60	13	151
1990	4	26	20	143	24	169
1991	5	29	7	21	12	50
1992	5	83	10	34	15	117
1993	3	29	5	14	8	43
1994	2	41	7	47	9	88
1995	7	21	8	40	15	61
1996	3	9	13	61	16	70
1997	3	11	14	128	17	139
1998	0	0	12	121	12	121
1999	1	5	7	26	8	31
2000	2	19	4	10	6	29
2001	3	24	5	16	8	40
2002	1	19	6	35	7	54
2003	1	34	6	41	7	75
2004	2	39	0	0	2	39
2005	2	5	4	17	6	22
2006	3	21	7	63	10	84
2007	1	7	8	27	9	34
Total	69	877	192	1222	261	2099
Average per year	3	38.1	8.3	53.1	11.3	91.2
Average hearing duration	12.7 days		6.4 days		8.0 days	

Source: NEB as per Table 1

However, there has been a significant reduction over time in the number of hearings and in the time devoted to them. For example, in the first six years there were 94 hearings and 1002 hearing days, but in the last six years only 41 hearings and 308 hearing days. There was still great variation from year to year. [10]

The change took place about the middle of this period. From the period 1985-1994 to the period 1995-2007, the average number of toll hearings per year nearly halved (from 4.0 to 2.2), and the average duration of a hearing more than halved (from 16.6 to 7.4). In consequence, the average number of toll hearing days per year fell to one quarter of the previous level (from 66.3 to 16.4). For non-toll categories, the change took place a little later, and was a little less marked.[11]

2.3 The impact of negotiated settlements

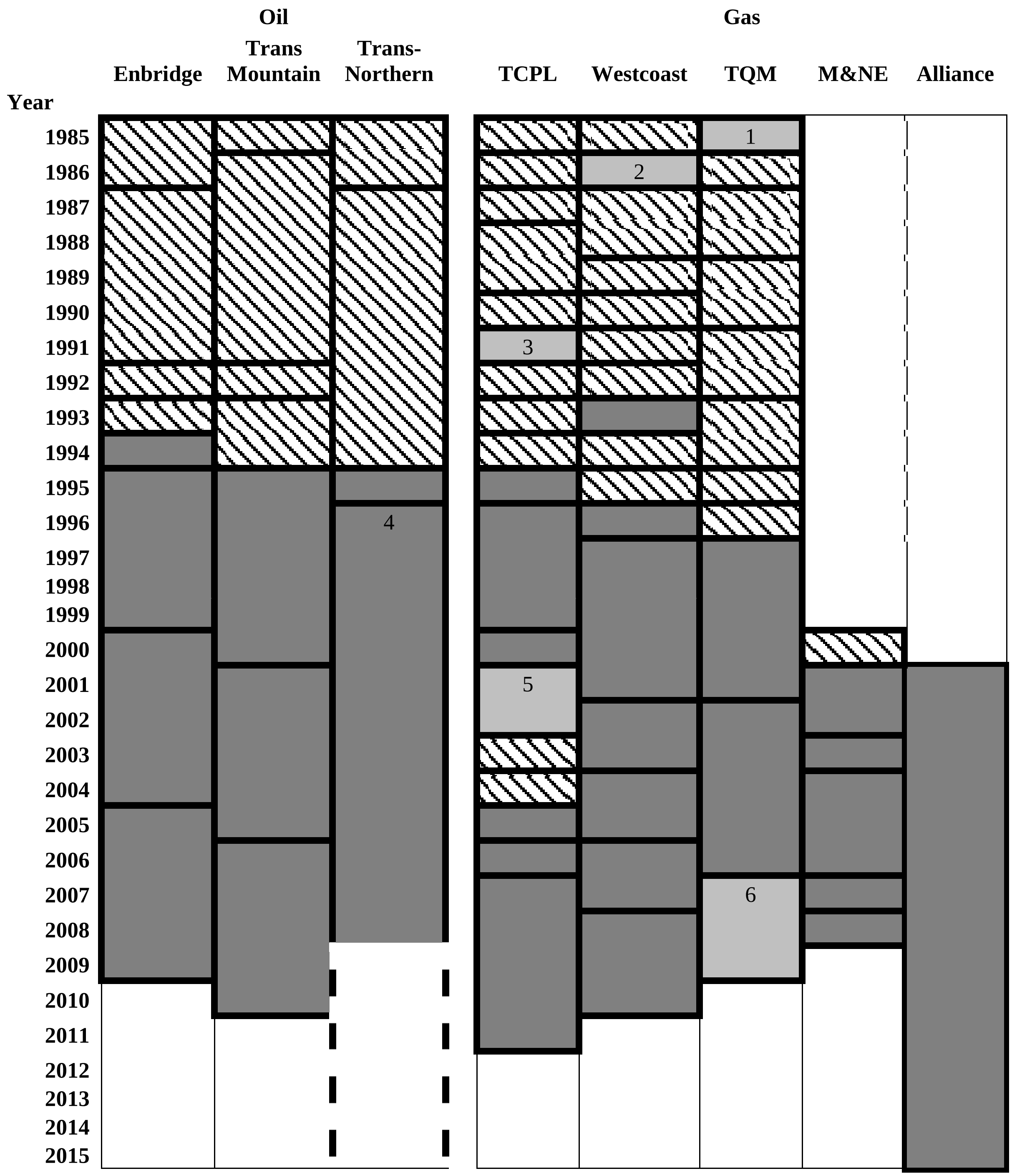
These changes in toll hearings were associated with the development of negotiated settlements. Figure 1 shows the extent to which each pipeline has negotiated settlements over the last two decades, including a few cases where the settlement did not cover all the issues or where the Board did not fully accept the settlement. It brings out clearly the dramatic change around the mid-1990s – as we shall see, essentially, before and after the Board's revised Settlement Guidelines of August 1994. Before then, all tariff applications were litigated; since then, all tariff applications by oil pipelines have been settled by negotiation, and most applications by gas pipelines.

It was noted above that there has been a significant reduction over time in the number of hearings of toll applications. Further examination of NEB data (not presented here) confirms that this reflects the impact of settlements. While 85 percent of litigated cases went to hearing only 16 percent of settlements did so.

[10] For example, for non-toll hearings the average time per hearing was nearly 14 days in 1986 and around 10 days in 1997 and 1998 compared to 3 days or less in 1991, 1993 and 2000. For toll hearings there have been exceptionally long hearings recently as well as in earlier days – for example, 5 pipeline toll hearings averaging over 32 days in 1987 and one taking 34 days in 2003 – compared to an average of 3 days or less in 1995, 1996 and 2005.

[11] From the period 1985-1998 to 1999-2007, the average annual number of hearings per day fell from 10.4 to 5.2, the average duration fell from 6.8 to 5.0 and the average number of hearing days per year fell from 70.5 to 26.1. The explanation for these changes in non-toll hearings lies beyond the scope of this paper.

Figure 1: Litigation and settlement activity at the NEB since 1985



Tolls set through traditional regulation (litigation)
Some contribution of settlement to toll determination
Tolls set through negotiated settlement
Tolls not yet determined

Source: NEB tariff decisions

Legend for numbered notes in Figure 1

1 – TQM 1985 settlement was not wholly accepted by the Board [see section 3.1]
2 – Westcoast 1986 settlement was not wholly accepted by the Board [see section 3.2]
3 – TCPL 1991 TTTF agreement did not include all parties [see section 3.4]
4 – Trans-Northern 1996 – 2000 toll agreement is renewed annually unless there are objections.
5 – TCPL 2001-2002 settlement excluded ROE [see section 4.3]
6 – TQM 2007-2009 settlement excluded ROE [see section 4.3 fn 54]

Table 3 compares the durations and regulatory processing times of litigated outcomes and settlements. The duration of settlements is typically longer than the duration of litigated outcomes, and in both cases typically longer for oil pipelines than for gas. In the decade 1985-1994, the litigations had an average term of 2.70 years for oil and 1.30 years for gas. In contrast, from 1995 onwards, the settlements had an average term of 6.88 years for oil and 3.05 years for gas (or 2.45 years excluding Alliance's 15 year settlement). [12] The average term of a settlement is thus more than twice as long as it used to be.

Table 3 Durations and processing times of litigated and settled outcomes

	Oil pipelines		Gas pipelines	
	Litigated 1985-94	Settled 1995-2008	Litigated 1985-94	Settled 1995-2008
Number of cases	10	8	23	21
Average term (years)	2.70	6.88	1.30	3.05
Average processing time (months)	8.03	2.78	7.35	4.74
Average processing time (months per effective toll-year)	2.97	0.40	5.65	1.55

Source: Figure 1 and NEB tariff decisions.

[12] These calculations include the full duration of the negotiated settlements, extending beyond 2006 where appropriate, but the open-ended Trans-Northern settlement is not taken beyond 2008.

It also takes the Board less time to process a pipeline toll application than a litigated one. For oil pipelines, it took on average 8.03 months to process a toll application under litigation, whereas it now takes 2.78 months with a settlement. For gas pipelines, the average time was 7.35 months with litigation, and is 4.74 months with a settlement. Thus, settlements have cut regulatory processing times by about a third for gas pipeline toll applications and by about two thirds for oil pipeline applications.

Since settlements typically are of longer term than litigated cases, the application processing time is incurred less frequently than with litigated outcomes. With litigation, the oil pipeline applications in this sample typically covered 2.70 years, an average of 8.03/2.70 = 2.97 processing months per effective toll-year. With settlements the average is 0.40 processing months per effective toll-year, a reduction to 13% of the previous level. Similarly, for gas pipelines the average has fallen from 5.65 to 1.55 processing months per effective toll-year, a reduction to 27% of the previous level.[13]

3. Initial settlement activity and Board policy: 1985-1994

3.1 The first negotiated settlement: TQM 1985

On 22 February 1985 the TQM gas pipeline applied for new tariffs. In its decision on this case the Board began by remarking on "the somewhat unusual background".

> The application was notable in that it had the support of several interested parties who had opposed TQM's requests in previous toll applications. TQM had meetings with these parties before the presentation of the application; consequently, an agreement was reached between them on certain matters which would influence the calculation of a just and reasonable toll, and on what would be a just and reasonable toll for TQM's transportation service.[14]

The Board therefore decided to conduct the proceedings by way of written submissions rather than hold a hearing. Despite the fact that "These parties placed on record that they considered the agreement to be an entity comprised of mutually dependent and inseverable matters", the Board performed a point by point analysis of the various issues of the application, which was of course the norm in litigated proceedings. With some minor qualifications the Board's decision in September 1985 was broadly consistent with TQM's application, except that the Board adjusted downwards TQM's applied-for and agreed rate of return on common equity, reducing it from 15.5% to 14.75%.

From the signatories' perspective, the Board had 'cherry picked' the agreement, in violation of their explicit provision. In the light of the Board's later enthusiasm for

[13] These figures do not include time required to process applications for annual updates of tariffs associated with multi-year settlements, but this has become a rather nominal process. Typically, such applications are put to the Board each year, which invites comments that draw no adverse response, and the Board approves the tariff revisions within a month or so.

[14] Decision RH-4-85, p. 1. The supporters included the Canadian Petroleum Association (CPA) and the Independent Petroleum Association of Canada (IPAC) (which later merged to create the Canadian Association of Petroleum Producers, or CAPP), and the provincial government's Alberta Petroleum Marketing Commission (APMC). The Minister of Energy for Ontario opposed the settlement.

negotiated settlements, it seems surprising that it should treat in this way the first agreement put to it. The Board's main concern seems to have been one of principle: it felt the need to determine independently that each of the proposed terms was just and reasonable. What the Board seems to have found particularly unacceptable was that TQM should receive an increase in its return on equity at a time when the cost of equity capital had declined.[15]

3.2 The second negotiated settlement: Westcoast 1986

Westcoast gathers, processes and transports natural gas from Alberta and North-east British Columbia (BC) to customers in southern BC and the northwestern US. In 1983, in response to pressure from shippers, the Board agreed to a review of Westcoast's method of regulation. In its Methodology Decision of April 1985 the Board agreed that there had been significant changes in circumstances in BC, following the adoption of a more competitive gas pricing policy by that province, and ordered Westcoast to file new tariffs as from January 1986 based on a new toll method. In December 1985 Westcoast did so.

The Board emphasised and described at some length "the profound changes in many aspects of its [Westcoast's] business brought about primarily by fundamental policy modifications by governments in both Canada and the US and by an unprecedented and unexpected decline in the price of crude oil".[16] But once again the Board jibbed at the proposed return on equity: the parties had agreed 14 per cent but the Board considered that 13.75 per cent would be a fair and reasonable rate.

It seems that the agreed return on equity emerged as Westcoast accommodated all the various interests in the substantial and complex transition to a new methodology of pricing, instigated largely at the request of the shippers.[17] But the Board still felt, as it had in the TQM 1985 case, that it had to determine for itself that each parameter of the settlement, taken separately, was just and reasonable.[18]

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[15] "TQM applied for a rate of return on equity of 15.5 per cent as compared to the presently allowed rate of 15 per cent. … [t]he expert witnesses for Ontario and TQM stated that the cost of equity capital had declined since 1984 and that their respective recommended rates of return on equity capital were lower for the current test year than was recommended in TQM's 1984 toll proceeding." RH-4-85, pp. 9 – 12.

[16] RH-6-85, August 1986, p. 7. In Canada, federal and provincial governments withdrew completely from natural gas pricing by November 1986, "resulting in what is generally termed market-oriented pricing, and the complementary need for open access transportation including a range of transportation services must be kept in mind." The BC government had also taken a series of far-reaching deregulation initiatives, as had the US.

[17] One correspondent has suggested to us that "During negotiations specific items were adjusted in return for other adjustments in order to obtain an overall settlement. Individual adjustments were not driven by a specific rationale. It was the overall result that was of paramount importance."

[18] The Board acknowledged that the settlement should be given weight. "However, given the Board's mandate, the existence of such a settlement cannot be the sole basis for determining the justness and reasonableness of the rate of return on equity component of the tolls applied for." RH-6-85, p. 87.

3.3 Drivers of change at the NEB

The Board's treatment of these two cases is generally accepted to have discouraged settlements. [19] Yet within a couple of years the Board was actively facilitating settlements, market participants appeared keen to explore the possibility further, and after eight years the Board had reversed its position. What factors led to this change of direction?

An important influence was the change in federal Government policy, which the Board could not ignore. [20] This went beyond the freeing up of commodity markets and, perhaps indirectly, brought about pipeline open access and impacted on the manner of pipeline regulation.[21] Within this new environment several key individuals at the NEB and in industry promoted the development of settlements.[22]

The Board also seems to have been influenced by more practical considerations. Unlike the situation at the FPC and FERC in the U.S., reform does not seem to have been driven by a backlog of cases. But the Board's thoughts were moving in the direction of regulatory reform in the early 1980s, especially on the need for "reasonably expeditious treatment of applications".[23] In 1987 the Board decided to take positive steps to improve the public hearing process, initially by consultation.

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[19] Those closely involved with negotiation settlements for much of the NEB history have expressed themselves forcefully to the authors. "The proponents viewed the agreement as 'an entity comprised of mutually dependent and inseverable matters' and felt strongly that it was a package deal which could be accepted or denied as a whole. When the Board cherry-picked the first TQM settlement, the strong message received by the pipelines was that there is absolutely no merit in pursuing further settlements, since there is only downside and no upside." This was later accepted by the NEB. "Not surprisingly, parties concluded that it was not worthwhile to undertake further settlement discussions until there was some clarity and commitment to the settlement process." Vollman (1996) p. 2.

[20] "Tribunals like the NEB have to take account of the policy environment created by the government of the day, while observing strict independence and objectivity in regard to treatment of specific applications. To do otherwise would be to thwart the operation of the democratic process. The Western Accord and the Halloween Agreement were needed for the Board to clear away the regulatory debris accumulated over the previous dozen years and set the industry on a course towards deregulation of commodity markets and eventual light-handed regulation of facilities owned by entities which retain market power, generally because of the natural monopoly characteristics of those facilities." Priddle (1999) p. 543.

[21] "The evolution of deregulation caused a highly regulated market to transform into one which fostered direct sales among willing sellers and buyers, based upon freely negotiated pricing, with transportation being available on an open-access basis. Gone were the days when merchant pipelines such as TransCanadaPipelines Limited bought gas directly from producers and sold it to eastern Canadian gas distributors." Miller (1999) pp. 420-1.

[22] Notably successive Board chairmen Roland Priddle (1986-1997), Kenneth Vollman (1998-2007) and Gaétan Caron (2007 to date), and several industry executives both before and especially after the Board's change of heart in the mid-1990s.

[23] Priddle (1999) p. 542. The frequency and length of hearings was a particular concern. As mentioned, Table 1 above shows that hearings took up 1000 days in the six years 1985 - 1990. In 1986-87 one case alone took 73 days. TransCanada PipeLines Limited (TCPL), 30 September 1986 to 27 February 1987. RH-3-86, May 1987, p. xv.

3.4 Facilitating settlements: the 1988 Guidelines

The 1987 consultation resulted in "a review of 20 regulatory areas which were targeted for improvement by interested parties".[24] Negotiated settlements were the first item discussed. The Board noted strong support for this, though there were diverse views on how settlement should be applied in practice and what role the Board should play.

The respondents' stated rationale for the introduction of settlements was that "Board acceptance of negotiated settlements in toll matters would shorten public hearing time or even eliminate the need for a public hearing, thereby reducing the cost of regulation."[25] Better mutual understanding was also hoped for, and no doubt better customer relationships. (The scope for incentive regulation or other innovations was not mentioned.)

In response to the various private interests, the Board explained that it had a duty to ensure that all tolls were just and reasonable, which required a careful balancing of the interests of the various parties concerned, which was why it conducted its hearings in an open forum. The Board considered that an acceptable settlement process would need to meet the following five conditions:

i) parties affected by a settlement should have a fair opportunity to participate and have their interests recognized and appropriately weighed;
ii) a negotiated settlement process should not fetter the Board's ability and discretion to take into account the full public interest which often extends beyond the immediate concerns of the negotiating parties;
iii) the settlement process must produce adequate information on the public record for the Board to satisfy itself that the negotiated settlement would result in tolls which are just and reasonable;
iv) the Board's role as an independent adjudicator must not be impinged by being a party to the negotiations; and
v) the Board cannot accept "package deal" negotiated settlements consisting of various elements, not all of which might, in the Board's judgment, result in tolls which are just and reasonable.[26]

It commented that "the Board will itself be examining issues as they come before it to determine if they might be candidates for a negotiated settlement, and invites potential applicants [the pipeline companies] to do likewise".

A parallel and helpful development was that of Joint Industry Task Forces (JITFs). They were initially established primarily to resolve matters dealing with operating practices, and were encouraged by the Board by about 1987. They soon began to complement the settlement process.[27] .

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[24] NEB (1988) p. 1.
[25] Because the Board allowed for recovery of regulatory costs by pipelines, and these costs ultimately were added to the tolls paid by shippers, shippers may have been more interested than pipelines in reducing explicit regulatory costs. However, both parties had an interest in improving the regulatory process and thereby reducing the use of company resources in the regulatory and hearing process.
[26] NEB (1988) p. 3.
[27] In 1991 TCPL would have presented a JITF report as a negotiated settlement had not certain parties objected because the JITF had not included them. The Board supported the process "as a means of streamlining proceedings". RH-1-91, p. 15.

3.5 The third negotiated settlement: Westcoast 1993

In July 1992 Westcoast Energy applied for new tolls effective January 1993. In October it informed the Board that it had reached settlement with four major users and a week later it identified further parties who supported or did not oppose the settlement.

The settlement embodied two main changes to the initial application. First, Westcoast reduced its operating and maintenance expenses and created a deferral account for unfunded debt, leading to tolls lower than had been applied for. Second, Westcoast agreed to accept the rate of return on equity that the Board would choose to allow for TCPL in the latter's toll case being heard in parallel to the Westcoast case. The cost to Westcoast of these concessions appears to have been low but they benefited shippers and consumers by reducing tolls and shortening proceedings.

This time the Board accepted Westcoast's settlement. Nonetheless its decision still contained an item-by-item examination and commentary on the main components of the conventional rate base calculation. The Board also required Westcoast to file sufficient evidence to support the decision.[28]

3.6 Additional initiatives and the Generic Cost of Capital

The Board now took a more active role in exploring reforms to regulatory procedures. In 1992 it initiated a public discussion on improvements to the traditional cost of service method of regulating pipelines. At an Incentive Regulation workshop in 1993, shippers argued for performance measures and monitoring as a basis for incentive regulation, but pipelines were lukewarm. A later outcome was the requirement for pipelines to file a set of Performance Indicators.

Also in 1993 the Board questioned the appropriateness of the traditional examination of hundreds of 'line items'. It concluded that an overall approach to O&M expenses – specifying a cost envelope – "would give the pipeline company more flexibility to respond to changing market conditions while providing an incentive to strive for more efficient operations."[29]

A particularly significant initiative was the Generic Cost of Capital hearing in March 1994. The Board was concerned about the duplication of evidence in different hearings, and also about the consequences of setting allowed returns at different times. To avoid annual hearings on the cost of capital the Board's aim was to develop an automatic mechanism to adjust the return on common equity. It established an annual basis for

[28] RH-3-92. Some interveners, while supporting the settlement, expressed concerns about the openness and transparency of negotiations and the ability of interested interveners to participate. The Board would have preferred more parties to be involved but accepted that there was a limited timeframe and that other parties had had an opportunity to participate.

[29] "This was another important cultural change because it contributed to more global thinking; a condition which would become even more important under incentive regulation." Vollman (1996) p. 4.

doing this, applicable to all pipelines.[30] This decision was intended to streamline the regulatory process by removing a contentious issue from individual hearings and to reduce the uncertainty in terms of a major cost item. [31] This seems to have struck a chord with many industry participants, who were increasingly skeptical about this aspect of regulatory proceedings.

The Generic Cost of Capital decision is generally considered "important as a building block for the subsequent gas pipeline settlements". [32] One correspondent suggests that it works in two ways. First, it takes off the table the issue of cost of equity, on which parties find it difficult to agree and which constitutes a 'zero-sum game'. Second, it sets a floor to the negotiation since no utility will accept less, so that discussions focus on the potential 'positive-sum game' of what additional value the utility can offer to merit additional revenue.

The law and economics literature suggests another way of putting the point: insofar as divergent expectations may lead parties to litigation rather than settlement, this decision significantly reduces the scope for such different expectations hence reduces the attraction of litigation. It may also be seen as clarifying the values of the property rights of the different parties, which in turn is conducive to negotiation and trade.

3.7 Revised settlement procedures 1994

Despite the publication of the 1988 Guidelines and the other regulatory initiatives, only one settlement had been reached (Westcoast 1993). Shippers and pipelines were generally supportive of settlements, though with different emphases. Subsequent accounts identify two main concerns. One was the Board's rejection of 'package deals'. The other was the Board's inclination to hold hearings even where settlements were reached. Revisions to the Guidelines therefore seemed necessary.

In August 1994 the Board published revised and slightly more detailed Guidelines for negotiated settlements. (NEB 1994). It repeated with some modification its previous five criteria for acceptable negotiated settlements. It expanded on the requirement to produce adequate information on the record.[33] It also introduced two main modifications to address the two concerns mentioned above.

First, the Board added a further procedural step and an assurance. "Upon filing of this information, the Board would invite interested parties to comment on the settlement. Should the settlement not be opposed by any party, the Board would normally be able to conclude that the resultant tolls are just and reasonable and a public hearing would not be required." There was no reference to the possibility of contested settlements.

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[30] RH-2-94.
[31] Caron (1995) p. 9.
[32] Priddle (1999) p. 547. Another correspondent ranks the Generic Cost of Capital decision as 'a watershed' comparable to the 'no cherry picking' promise in the revised Guidelines (see below) in terms of facilitating settlements.
[33] It now specified that the applicant should provide a tabulation of the components of the agreed revenue requirement, the resulting tolls, an explanation of their derivation, and any tariff changes, accompanied by a concise description, explanation and rationale for the resolution of each issue.

Second, whereas the original 1988 Guidelines prohibited package settlements if they included some elements that might not be just and reasonable, the new provision was simply that "the Board will not accept a settlement which contains provisions that are illegal, or contrary to the *National Energy Board Act*."

These amendments did not explicitly preclude the Board from cherry picking in the way that had previously caused problems. Significantly, however, and apparently without further explanation, within eighteen months the Board was adding the additional provision: "When presented with a settlement package, the Board will either accept or reject the package in its entirety."[34]

The net effect was not simply to reinforce the Board's support for negotiated settlements. In effect, the revised 1994 Guidelines reversed the Board's previous position that "the agreement cannot, per se, be the vehicle for determining the justness and reasonableness of the tolls applied for". Henceforth, the Board would judge the reasonableness of a settlement by the reasonableness of the *process* rather than by the reasonableness of the *outcome*.[35] The significance of this change was not lost on commentators and participants.[36] From the perspective of economists, the Board's revised Settlement Guidelines may again be seen as clarifying and indeed establishing the property rights of the parties, which again (per Coase) is likely to facilitate bargaining and mutually beneficial outcomes.

4. The blossoming of settlements: 1994 to the present

4.1 Multi-year incentive agreements

At about this time there was also a change in economic conditions and attitudes in the industry.[37] At the Board's incentive regulation workshop, producers wanted to move to a price-setting system where pipeline owners would face greater incentives to reduce costs – that is, incentive regulation. Perhaps the industry had not initially been enthusiastic

[34] The additional phrase was not used in the Board's earlier decisions on IPL's settlements for 1994 and 1995-9, but has been used since 1996. E.g. NEB 1996-03-01 Reasons for decision Trans Mountain RHW-2-96, p. 5. NEB 1996-06-01 Reasons for decision RHW-3-96 Trans-Northern Pipelines, p. 3.

[35] The then-chairman Roland Priddle put it to the authors this way: "The Board simplified the Guidelines essentially to say: if you the regulated entity advise your whole community that you are going for a negotiated settlement, if you subsequently allow into the negotiations any party that has a demonstrable interest, and if there is broad agreement among parties, then we will consider that the public interest has been upheld and satisfied."

[36] "The acceptance of negotiated settlements is a critical breakthrough in the evolution of light-handed regulation. The breakthrough was the recognition that the consensus of the affected parties as to what was fair and reasonable did not need to be subjected to further scrutiny in accordance with some higher ideal of the public interest that existed in the eye of the regulator. In other words, the consensus of the affected parties was a good measure of the public interest." Schultz (1999) p. 388

[37] "Pipeline companies, which for decades had identified management of the regulatory process as a core competence, were now more concerned about competition and keeping their costs as low as possible to retain business. Users of the pipelines had grown disenchanted with a regulatory process that was costly, time-consuming, and at which they felt they could not win." Vollman (1996) p. 6.

about various reforms urged by the Board.[38] But by the time the Guidelines were updated, the industry had taken the leadership in these matters. There was a general feeling that hearings represented "inefficiency without reward", a zero-sum game to no mutual benefit, and were not conducive to a good relationship between customers and service provider, whereas settlements offered the promise of something better.

The combination of revised Board policy, evolving economic conditions and active industry leadership led to significant new developments. The first manifestation was a settlement for 1994 tolls with IPL (later Enbridge), the largest oil pipeline in Canada, negotiated "in an effort to minimize the time and cost involved in examining IPL's toll application".[39] It defined the "standard" parameters used in the toll making methodology, including rate base, rate of return on different elements and toll design, and contained no explicit incentive mechanism, but IPL was rewarded for focusing on issues important to the other parties[40].

Thereafter, the Board approved a rapid succession of multi-year negotiated settlements. [41] In 1996, over 90% of revenue requirements of Group 1 pipelines were based on these settlements. By 1997 all six of the Group 1 pipelines then subject to active regulation had entered four- or five-year negotiated incentive-based settlements.

The settlements generally included incentives to reduce costs, and provisions to share savings between the pipeline and its shippers, but often went further.[42] The Board was quite explicit that it had not designed the form of these developments, but it clearly favoured incentive regulation and sought to explain how these agreements operate, and how they reduce regulation.[43] It is interesting to note how they differ from regulated outcomes in other jurisdictions.[44]

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[38] Priddle (1999), p. 545.

[39] IPL letter to NEB dated November 22, 1993, submitting the negotiated settlement for 1994 tolls.

[40] The settlement provided for a payment to IPL of $1m over the applied for 1994 revenue requirement, with the justification that IPL was not expected to attain its 1993 allowed rate of return of 11.5 percent, and this increase in the revenue requirement would save the cost of a regulatory review and "permit the Board, IPL and the industry to focus on a timely expansion of ex-Alberta crude pipeline capacity and the pressing matter of crude oil apportionment". IPL letter to NEB dated November 19, 1993, detailing negotiated settlement for 1994 tolls.

[41] On the oil side, in March 1995 IPL signed a five-year incentive settlement covering tolls for 1995-1999. The two other major oil pipelines, TransMountain and Trans-Northern, soon followed suit with five year settlements. On the gas side, TCPL, the largest gas pipeline, settled all revenue requirement issues for 1995 (except the cost of capital which was being dealt with by the Generic Cost of Capital hearing). The parties then agreed a four year Incentive Cost Recovery and Revenue Sharing Settlement for 1996-2000. Westcoast agreed a settlement for 1996 then a five-year incentive-based settlement for 1997-2001. TQM also agreed a five-year incentive-based settlement for 1997-2001.

[42] The introduction to TCPL's 1996-2000 settlement (not necessarily the most advanced example) suggests how far the aims of the parties had evolved beyond shortening hearing times and streamlining regulation. Among the primary objectives of settlements it mentions "to more closely align the interests of the Parties by providing a framework which encourages efficiency gains, cost minimization and maximization of system utilization". Other primary objectives mentioned are lowering costs and tolls while maintaining or improving service quality and the financial integrity of TCPL, and preserving firm shippers' flexibility and ability to utilize their transportation contracts. RH-2-95.

[43] "Incentive regulation has developed mainly through multiyear toll agreements negotiated between pipelines and interested parties…. Such agreements provide for a sharing of the benefits that may result from improved performance by the pipeline. Typically, parties agree to a baseline level for costs which

These multi-year settlements began to change the form of regulation. Approving the annual updating of tolls within the term of an existing agreement was now straightforward. Even new agreements occasioned little or no concern, allowing the Board to accept them within a month or two, including a period for public comment. In effect, settlements transferred the major pipelines from an active to a more passive form of regulation.

4.2 Competition and flexibility: Westcoast's transition to light-handed regulation

In one novel and important pair of settlements, Westcoast and its users quite explicitly designed and achieved a transition to "a new scheme of light-handed regulation", which covered about half of the pipeline's regulated business.

Westcoast's application for 1995 tolls had been dealt with in the traditional way, and it had reached a one-year settlement for 1996 tolls. The break-through was a five-year settlement with the Canadian Association of Petroleum Producers (CAPP) for 1997-2001 tolls. The stated motivation for this settlement was the changing economic and commercial environment. This included significant development of gas resources in the adjacent Northeast BC; Westcoast's declining market share in the face of competition, resulting in higher tolls as costs were spread over a lower demand; shipper dissatisfaction with the rigidity and uncertainty of the existing toll structure; and the inability of Westcoast, under the current regulatory environment, to quickly develop new capacity and respond to customers.[45]

The settlement embodied toll increases, but more importantly a much greater flexibility in pricing. For Westcoast's increasingly competitive gas gathering and processing activities, it provided users with a choice of fixed tolls for 1, 3 or 5 years, adjustments tied to the price of gas, a bidding process for interruptible tolls, a revenue deferral account for differences between actual and base level toll revenues, and tolls for available and incremental capacity to be determined through individual negotiations.[46] In addition, there were agreed changes to accounting policies and procedures (e.g. on depreciation) and agreed principles with respect to service reliability.

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may be lower than what the pipeline applied for under cost of service regulation. Some protection is afforded to the pipeline for uncontrollable cost escalation along with a share of the rewards for keeping costs below the target level. Similar incentives can apply to efforts by the pipeline to increase throughput and revenue." NEB 1997, p. 2.

[44] For example, compared to the incentive price controls determined by UK regulators, the negotiated cost projections appear to be less aggressive in terms of future cost reductions; there seem to be more adjustment factors, risk sharing arrangements and escape clauses; and there is more revenue-sharing, typically on a 50-50 basis.

[45] Westcoast's competitors, subject to provincial rather than federal jurisdiction, could design a plant and put it in service in about nine months.

[46] For Westcoast's less competitive activities, there were simpler but nonetheless innovative provisions for transmission tolls, including 1) the option of a fixed toll for a 5 year period or a toll calculated annually according to a prescribed methodology, 2) basing the revenue requirement for the latter on the previous year's actual costs and a fixed escalation factor, adjusted to share any variance from base revenue requirement, and 3) a bidding process for allocating interruptible service.

The settlement also foreshadowed a new development going beyond the concept of multi-year incentive regulation, namely, a transition to freely negotiated market based arrangements subject to a lighter form of regulation.[47] Westcoast was exceptional among Canadian pipelines in the extent of its involvement in gas gathering and processing activities upstream of the long-distance transmission market. These activities were increasingly subject to competition.[48] Recognition of a number of factors suggesting that Westcoast would not be able to exercise market power gave the parties confidence to proceed.[49]

On 5 March 1998 Westcoast filed its Framework for Light-handed Regulation document which amends the 1997-2001 settlement by providing the mechanism by which Westcoast's tolls for gas gathering and processing services will be based on *individually* negotiated arrangements.[50] It is a quite remarkable document. To illustrate with just a few provisions, the goals of the Framework include to provide shippers and Westcoast the opportunity to negotiate service requirements as in a competitive market, and where possible to rely on commercial arrangements instead of regulatory oversight. The Introduction recognises that shippers are knowledgeable and have information and other options. The Fair-Dealing Policy requires Westcoast not to discriminate and to make information about capacity available to all on a monthly basis. The Contracting Practice provides that terms will be governed by contracts negotiated with individual shippers. "The goal is to permit negotiations to include any item of value that could be the subject of bargaining in a competitive market."

The parties recognised the need for commercial confidentiality, but also "the need for a reasonable degree of price discovery to assist in the operation of a functioning market". To that end they propose that Westcoast would either file all contracts with the Board or indicate the maximum and minimum range for the tolls in each tariff; allow the Board access to contracts for mediation or complaint purposes; and make available quarterly summary data on contract terms. There is provision for a detailed Complaint Process, including optional mediation, arbitration and adjudication by the Board. Westcoast accepts responsibility for the utilization of its gathering and processing assets and for the

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[47] "The parties to the Settlement contemplate that by the end of the term of the Settlement, Westcoast and shippers will be freely negotiating market-based arrangements in a manner consistent with the provision of service by Westcoast on a competitive basis such that light-handed, complaint-based regulation would be appropriate….The principles of this new regulatory approach will be the subject of further negotiations, which the parties intend to complete by 31 December 1997 and will be subject to Board Approval; and the parties have also agreed to negotiate the terms of a policy governing the interconnection of the gathering or treatment facilities of third parties with Westcoast's facilities."

[48] In 1995 a report to the British Columbia government suggested that the upstream activities could in fact sustain competition and that " Westcoast was an unnatural monopoly with the consequence that a different approach to regulation was appropriate." See Schultz (1999), who also describes the origins and nature of the Westcoast pipeline system.

[49] These factors included the absence of economies of scale, new technologies and new construction techniques reducing barriers to entry, opportunities to enter based on different customer service needs, increasing actual rivalry, Westcoast competing for new business (and with itself) via a new subsidiary, new processing capacity built outside Westcoast, knowledgeable customers with buying power, limited scope to extract profits and customer pressure to be cost efficient, alternative opportunities in Alberta, and competition from an actual new entrant. Schultz (1999)

[50] Key Documents Related to the Board's Decision on the Framework for Light-Handed Regulation, National Energy Board, June 1998.

stranding of any of those assets, and for the gain or loss on any disposal.[51] There is explicit provision for interconnection.

The Board still has a role in terms of complaints, and can intervene if needed, hence the term “light-handed regulation” meaning ‘market regulation’ rather than ‘deregulation’. But the contrast with conventional regulation is marked. In particular, certain services are henceforth to be provided by negotiated settlements between a pipeline and *individual* shippers. As Schultz (1999, p. 389) observes, “The consequence of such a regulatory model is the potential, and the probability, for greater differences in service arrangements than would be contemplated by traditional approaches to cost of service regulation.” Although many of the oil pipeline settlements were innovative in different ways, this settlement fundamentally altered the approach to regulation, and through the whole of the gas gathering and processing ‘value chain’. For this reason the same author has referred to this (in correspondence) as “perhaps the most innovative of all deals”.

4.3 Non-unanimous and contested settlements

In welcoming the succession of multi-year settlements in the late 1990s, the Board anticipated that litigation to determine tolls would be used more selectively. In fact, the Board was soon called upon to act again.

For each of the ten years from 1985 to 1994 TCPL’s tolls had been determined by litigation, generally on an annual basis and taking an average of 32 days per hearing. For 1995 the company and the other parties in the Tolls Task Force (TTF) were able to settle all outstanding revenue requirement issues. (The cost of capital was being dealt with by the Generic Cost of Capital hearing.) For 1996-1999 the parties agreed (via TTF resolutions) on toll design issues and on a four year Incentive Cost Recovery and Revenue Sharing Settlement that incorporated the generic cost of capital formula.

Then the mood seems to have changed. When the Incentive Settlement expired at the end of 1999 the parties found difficulty in agreeing a one year extension for 2000. For the two-year period 2001 and 2002 TCPL and 13 signatories achieved a Services and Prices Settlement of all issues except the rate of return on equity (including capital structure), but the settlement was contested by other parties. After an oral hearing the hearing panel approved the settlement but noted that the Board’s 1994 Guidelines did not address the situation of a contested settlement, and recommended that the Board review the Guidelines to examine contested settlements and the potential for the use of Alternative Dispute Resolution (ADR) mechanisms.

Now anticipating a possible lack of agreement between parties in the new competitive environment, the Board updated its 1994 Guidelines in 2002 “with the explicit goal of

[51] If Westcoast is considering disposal it will make the assets available to other potential acquirers. Disposition of assets to its affiliates must be done by competitive bidding. “This contrasts sharply with the traditional cost of service approach in which under-utilization typically falls on the shoulders of the remaining shippers. The Framework thus establishes a new point of reference for risk and reward issues.” Schultz (1999) p. 41.

providing flexibility to effectively address contested settlements".[52] The Board also made a few small modifications to reduce the prescriptive nature of the 1994 Guidelines.[53] On the other hand, after the previous presumption that a non-opposed settlement would normally be approved, the Board introduced the qualification that "in unusual circumstances" the public interest might necessitate further investigation.[54]

Whether the lack of agreement between TCPL and other parties was entirely the result of the new competitive environment is debateable. TCPL appears to have been more demanding than other pipelines, which antagonised the other parties. It did not accept the Board's generic cost of capital decision, applied for a higher return than the formula would imply, and repeatedly challenged the Board's conclusions. Moreover, apart from cost of capital, TCPL and other parties did not settle other tariff issues either, so TCPL's 2003 and 2004 tolls were once again determined by the traditional method of litigation. Thus, for about four years (2001 to 2004) TCPL was largely at odds with its stakeholders and with the Board.

Once the cost of capital issues had been resolved, however, the parties seem to have worked to improve relations. TCPL's 2005 and 2006 toll revenues were settled by agreement, and incorporated the generic cost of capital formula. These were not multi-year incentive settlements but the second one included some one-year incentives to efficient fuel consumption and to achieve a variety of specified performance targets. Subsequently, TCPL agreed a five-year settlement for 2007-2011.

4.4 The present state of play

All the major pipelines continue to negotiate with their users and all are still on terms determined by settlements rather than litigation.[55] The scope of settlements continues to expand. Investments in new pipeline facilities have been based on contractually agreed-to

[52] The revised Guidelines provided for the Board to hear the applicant's arguments in favour of the settlement, the views of parties opposed to the settlement, and the applicant's response to the opposition. The Board would then decide whether to approve or deny the settlement or allow it on an interim basis and hold a hearing to deal with the issues raised by the dissenting parties. This approach is less cumbersome and costly than going to litigation, which some would advocate, while still allowing all parties to participate in the decision process. It encourages the applicant to continue to seek a settlement even where not all parties can agree.

[53] In particular, the Board "recognizes that the requirement to provide a detailed breakdown of the revenue requirement may constrain the flexibility of parties in reaching a negotiated settlement and has therefore adopted more flexible wording for the requirement". The applicant now had to provide "an explanation of how the agreed-upon revenue is determined" instead of "a tabulation of the components of the agreed revenue requirement". This is consistent with the Board's commitment to either accept or reject a settlement in its entirety and not cherry-pick.

[54] The Board also raised at this time the possibility of Board staff taking an expanded role in the settlement process. In addition it suggested "that a pipeline company, in submitting its negotiated settlement for approval, should provide reasons as to why agreement could not be reached with all parties on all issues". However, it withdrew both proposals in the light of widespread opposition.

[55] In the oil sector, Enbridge and Trans Mountain have agreed further five-year settlements and Trans-Northern continues to file annual toll revisions consistent with an Incentive Toll Settlement originally made in 1996. In the gas sector, Alliance continues to file annual revisions under its 15 year settlement, Westcoast has agreed a series of two-year and three-year settlements, TCPLhas agreed a five-year settlement, M&NE has agreed a variety of settlements of one to three years, and TQM has recently agreed a three-year settlement of all issues except cost of capital (which has just gone to hearing).

sharing of risks between shippers and pipeline proponents.[56] There have been provisions for maintaining and improving service quality, including the development of detailed metrics associated with quality, predictability and reliability, and associated bonuses and penalties.[57] The record indicates the extent to which the regulatory role can be minimized.[58] Negotiated settlements are also spreading beyond the actively regulated Group 1 pipelines to those pipelines regulated on a complaint basis. This again suggests that the impact of settlements goes beyond reproducing what regulation would otherwise achieve.

No institutional arrangement is ever perfect, of course, and shippers would naturally like lower prices and more innovative services.[59] But all market participants (including shippers) support the principle of negotiated settlements, and have continued to renew them. Settlements are also associated with a successful rather than unsuccessful system of hydrocarbon transportation.[60]

5. Concluding remarks

It is to the credit of the National Energy Board that it has presided over – indeed, actively facilitated - a significant change in regulatory approach. The prime role of the Board is no longer to impose its own view of the public interest. It is to enable well-informed market participants with a demonstrable interest to negotiate satisfactorily on something like equal terms with the oil and gas pipelines. The Board seems to have performed this role remarkably well for some fifteen years. Key elements in the success of the Board's approach were the Revised 1994 Settlement Guidelines and its Generic Cost of Capital decision, which together established and clarified the property rights necessary for the parties to negotiate mutually advantageous settlements. Relevant too was the emergence of a more competitive environment which increased the benefits from a shift from rate of

[56] Miller (1999).
[57] Cf. settlements with Westcoast 1997-2001 and particularly Enbridge since 1995. The last Enbridge settlement (2005-09) indicates the thoroughness and imagination embodied in settlements. The Principles of Settlement between Enbridge and CAPP comprise 76 pages. The total documentation supplied by Enbridge as part of its application runs to some 250 pages. The service metrics comprise 31 of these, plus a further 38 pages specifying service levels.
[58] NEB's response to the documentation mentioned in the previous footnote comprises only 2 pages plus a Schedule. NEB simply related that it acknowledged the application on 19 December 2005, invited comments on 23 December, received no comments or opposition, considered that the revenue requirements and tolls were just and reasonable, and approved them on 27 January 2006.
[59] An NEB survey of shippers' views of pipeline performance reported average scores of 3.02 (out of 5) on whether tolls were competitive and 3.04 on pipeline company's attitude to continuous improvement and innovation, a range from 3.26 to 3.37 on responsiveness, fairness and suite of services, a range from 3.57 to 3.75 on timeliness and accuracy of invoices, provision of operations and commercial information and quality of service, and 4.06 on physical reliability and communications. Satisfaction with collaborative processes and the current negotiated settlement agreement or tariff were rated 3.25 and 3.29. Satisfaction with whether the NEB has established an appropriate regulatory framework in which negotiated settlements can be reached was 3.54. NEB (2006) p. 22 and Appendix Two.
[60] The NEB (2006 p. 37) concludes that there is adequate capacity on existing gas pipelines; capacity is tight on the oil pipeline system but there are a significant number of proposals to build or expand these pipelines; shippers continue to indicate that they are reasonably satisfied with the service provided; and NEB-regulated pipelines are financially sound.

return to incentive price cap regulation, which the Board in its conventional role could not deliver.

This raises the question of when it is appropriate for a regulatory authority to establish such property rights – or delegate such discretion - to the regulated parties. Are more innovative settlements always in the public interest or could they be at the expense of final customers? What about the interests of parties not at the negotiating table and parties who contest the settlement?

The Board's duty includes the promotion of economic efficiency in the Canadian public interest. In an increasingly competitive market it can perhaps assume that the interests of final (downstream) customers are sufficiently protected by the users (producers, shippers and large consumers) and by downstream competition. [61] In other contexts, regulators have drawn on such arguments while explicitly cognisant of the duty to protect the interests of parties not at the table.[62]

What about contested settlements? In the only contested pipeline toll settlement that the Board faced, it concluded that there was no evidence that the settlement was inconsistent with the Act. It revised its Guidelines in the expectation of more contested settlements, but in the event this was not the case. Elsewhere, FERC has applied a set of four tests as an alternative to requiring unanimous agreement.[63]

There is scope for further research on settlements. At the NEB, how does the experience of settlements for Group 1 pipeline toll cases compare with the experience of Group 2 pipeline toll cases and Group 1 non-toll cases? Is the experience replicated at provincial level and if not why not? A systematic comparison of regulatory policies and the extent of settlements in different US jurisdictions would be insightful, including with respect to the encouragement or otherwise of settlements, and treatment of the interests of absent and contesting parties. From a formal perspective, Wang (2004) modelled a two-dimensional decision where the outcomes and tradeoffs were observable rather than those aspects of the FERC settlements that involved rate moratoria and must-file provisions. Such provisions, and the incentive mechanisms that lie at the heart of settlements in Canada and Florida, remain a challenge for proponents of more formal modelling.

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[61] This may be the case at FERC too: Wang (2004) reports no explicit consideration of final consumers. In Florida the main party negotiating with the utility has been the Office of Public Counsel (representing small and residential consumers) and numerous larger consumers have been co-signatories of the settlements.

[62] In endorsing capital expenditure plans and other measures agreed between the airport and airline users, the UK Competition Commission (2008) said "We took the view that the airport's airline customers are generally in a much better position than the regulator, the CAA, to suggest what development is needed at the airport, even recognising that these interests might, on occasion, diverge from the interests of future airlines and passengers, whose interests should also be represented." (para 24. p. 8) "We considered whether the interests of potential new airlines at the airport or passengers might deviate from the interests of current airlines in these decisions, but we found no reason to believe that they did." (para 24. p. 8)

[63] Out of 39 cases studied by Wang (2004), 22 were unanimous and 17 were contested. FERC approved the latter on the grounds that in 6 cases the contentions of the contesting parties lacked merit, in 2 cases the contesting parties would not be better off if the case were litigated, in 3 cases the interests of the contesting parties were too attenuated, and in 6 cases FERC approved the settlements for the consenting parties and severed the contesting parties, thereby allowing the latter to litigate their case separately.

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Appendix D8-2

INCENTIVE REGULATION IN THE UNITED KINGDON AND THE UNITED STATES: SOME LESSONS

Michael A. Crew and Paul R. Kleindorfer, 1996

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Incentive Regulation in the United Kingdom and the United States: Some Lessons[1]

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In view of the ubiquity of incentive regulation in the United Kingdom and its growing importance in the United States and elsewhere, it is appropriate to devote a special issue of the *Journal of Regulatory Economics* to this subject. Indeed, in the absence of practical developments in regulation, notably incentive regulation, the *JRE* itself would probably not exist. In this paper, we will provide context for the current developments in incentive regulation. We will explore the process of implementing incentive regulation, comparing the differences between the United States and the United Kingdom, and attempting to draw some lessons.[2] In so doing, we will briefly review the contribution of the papers in this issue. Section 1 will be, by way of background, concerned with some of the forces driving the adoption of incentive regulation. Section 2 will be concerned with alternative approaches and practical compromises made in the adoption of incentive regulation. Section 3 examines implications for the future direction of incentive regulation in the United States and the United Kingdom Section 4 provides a brief summary and conclusions. An example of a self-revealed regulatory mechanism is provided in the Appendix.

1. Background

Following the electoral success of Mrs. Margaret Thatcher in May 1979, her Conservative Government embarked upon a policy of privatization of Britain's numerous public enterprises. The monopoly status of many of these enterprises and the absence of institutions for monopoly regulation meant that a regulatory system had to be created de novo. The

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1 We would like to thank Jasmin Ansar, Tony Di Piero, Sarah Goodfriend, Thomas Lyon, J. R. Norsworthy, John Sawkins, Dennis Weisman, and Anthony White for helpful comments on an earlier draft.

2 The United Kingdom experience has been examined in a comprehensive and rigorous manner by Armstrong, Cowan, and Vickers (1994).

publication of the British Government report (Littlechild 1983) marked the beginning of the process leading to the creation of regulatory institutions and the adoption of incentive regulation in the form of price-cap regulation (PCR) in the United Kingdom. The United Kingdom approach to PCR also was adopted in other Commonwealth countries, notably Australia and New Zealand. In the United States, with its extensive history of regulation of monopoly through commissions and the attendant institutions of cost-of-service or rate-of-return (ROR) regulation, the adoption of PCR and other forms of incentive regulation did not occur as quickly, but in a more gradual and sometimes haphazard manner.[3]

Although incentive regulation has a clearly understood meaning in regulatory economics, all regulation, strictly speaking, is "incentive" regulation, as Lyon (1994) pointed out, in that it generates certain incentives that affect economic behavior. This is just as true of ROR as PCR. However, the thrust of traditional ROR regulation has been rather different than what is normally thought of as incentive regulation. ROR embodies micro management and is a form of cost-plus regulation in that the company normally can only persuade its regulators to change, let alone raise, its prices and revenue if it can show that its costs have changed. Revenue, or "revenue requirements" are derived from operating costs plus capital costs plus a return on capital, with the latter being the company's source of profits. The incentives for cost economy in ROR are weak, and economists have criticized ROR's efficiency properties in rather strong terms since the original paper on this topic by Averch and Johnson (1962).[4]

By contrast, PCR, the original form of incentive regulation as proposed in Littlechild (1983), has always been touted as having superior efficiency properties to ROR. It is an attempt to depart from the micro management of ROR. The idea is that the company should be subject to a cap on its prices. Its prices would be allowed to increase by some general index of prices, for example, the CPI, less an amount X, the "X factor." The monopoly customer would then be guaranteed that the level of prices charged would decrease (by X) in real terms. And the regulated company would be assured that (some index of) its prices would be allowed to increase at a rate not to exceed the CPI-X formula.[5] PCR offers some clear incentives for efficiency that were not traditionally operating in ROR regulation. Under PCR, the company has an incentive to minimize costs and generally improve the efficiency of its operations over time, in that it pockets all the profits, at least for the period over which the price cap applies, known as the price-cap period. Thus, while PCR, as practiced in the United Kingdom, provides sharper incentives for efficiency than ROR, in part by eliminating micro management, there are some similarities. For example, the problem of price-cap renewal may introduce micro management, with the companies being asked for significant additional information by the regulator. Price cap renewal, in theory and practice, is recognized as the most likely time for PCR to adopt some of the inefficiencies of ROR. On

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3 However, everything is relative. By the standards of regulatory institutions in the United States, the change might be considered rapid.

4 Of course, it could be argued that ROR served a very useful role in the high-growth periods in the middle of this century in securing rapid investment in key infrastructure (rather than in inducing cost minimization). Clearly, the situation has changed in a number of respects (competition and technology being the most evident) since ROR was first adopted, and incentive regulation may be viewed as a response to these changes.

5 As Law (1995) has examined in some detail, the cap could apply to the price of each individual product as an alternative to the index of the company's prices. However, the usual implementation of PCR is through a price index applied to a basket or set of baskets of the company's services.

the other hand, if there is sufficient "regulatory lag" between review periods, ROR looks similar to PCR (with an X = 0) and arguably attains some of the efficiency properties of PCR.

Incentive regulation in the United States includes PCR of the United Kingdom variety, but it also describes all sorts of other schemes. As United Kingdom style PCR is unadulterated by the restrictions applied often in the United States, we join Kridel, Sappington, and Weisman (1996) (KSW) in referring to United Kingdom-type PCR as "pure" PCR. Sometimes attenuated PCR and other schemes go under the name of "performance-based regulation" or PBR.[6] All of these schemes offer an incentive to companies to operate more efficiently, in that they allow the company to retain some of the benefits of increased efficiency. Sometimes they incorporate "sharing:" the regulator determines a base allowed rate of return; if the company earns at a higher rate it shares in the excess profits with the consumers. Lyon (1996) explores in detail the efficiency properties of sharing schemes and argues that total welfare can always be enhanced by moving from pure PCR to a properly designed sharing plan. Variations of such schemes are discussed in detail in the survey article by KSW.

The applications of incentive regulation in the United Kingdom and in the United States have taken somewhat different routes. The United Kingdom had the advantage of establishing a regulatory scheme from scratch unfettered by the burdens created by the existing system of ROR regulation that existed in the United States The United Kingdom also had the impetus from privatization and a Prime Minister who believed her homespun elementary economic theory, advocated it to the faithful with a passion, and applied it with great fervor. Moreover, as Prime Minister, Maggie Thatcher had the clout to bring about the sweeping changes that she envisaged (Bolick 1995). The United States, by contrast, not only did not have a leader with a mission like Mrs. Thatcher but was also encumbered with its existing mature regulatory institutions, which proved difficult to change.

Despite some real pressures to reform the system of regulation, regulatory institutions provided a major drag upon change. Pressure came from a number of sources. One source was the academic writings of economists, dating from Averch and Johnson's (1962) paper criticizing existing ROR regulation. Such criticisms took a number of forms, for example, Crew and Kleindorfer (1986) expressed concerns about the transactions costs of the process of ROR. Economic theorists, for example, Laffont and Tirole (1993) and Sappington (1994), were not to be left out of the chorus who argued that ROR resulted in various inefficiencies. While we are some of the last people to underestimate the power of an idea, we do not believe that it was the chorus of economists, singing surprisingly in unison, that spurred the progress toward incentive regulation. The real forces for change came from public dissatisfaction with the previous system, coupled with the iron will of Lady Thatcher, and changes in technology and increased competition. These forces pushed the process away from ROR, which was unsuited to the demands of the new environment, to more flexible regulatory mechanisms such as PCR. As competition and technology continue to change, the potential for the increased application of incentive regulation increases. These twin forces of technological change and competition, interacting with the inertia of existing interests and with pressure groups such as environmentalists, are what shaped the development of incentive

6 For an interesting case study of performance-based regulation (PBR) as applied to San Diego Gas & Electric, see Schelhorse and Keehn (1994).

regulation in the United States We will now discuss the operation of this process in the United States and draw some lessons and comparisons from the United Kingdom

2. Alternative Approaches to Incentive Regulation

In the United Kingdom, PCR in the "pure" form of (RPI - X)[7] has been applied to almost all of the formerly nationalized and now privatized industries. These include not only traditional network industries but companies such as the British Airport Authority.[8] The network industries—electricity generation and distribution, gas, water, telephone, and transportation—are all subject to pure PCR except for the National Grid Company, which has been subject to a revenue cap, which we will discuss further below. The water industry presents an interesting contrast, because rates have been allowed to increase in real terms in contrast to the other industries whose rates have been required to fall in real terms (by X per cent per year, with X varying by industry and time period). The increase in rates in the water industry has been justified by the requirement of complying with more stringent European Community directives on water quality.[9]

By contrast, in the United States, the pure form of PCR is rather scarce. MacDonald, Norsworthy, and Fu (1994) examine incentive regulation in telecom, cited as the most competitive of the network industries, and note the striking paucity of pure PCR.[10] One argument they make is a concern on the part of regulators and, perhaps, companies for uncertainties that may be generated by pure PCR.[11] Other explanations may stem from the desire on the part of managers and regulators to attempt to maintain the status quo. Many of the incentive plans incorporate all sorts of restrictions on PCR, including limits on the maximum rate of return that the company is allowed to earn and a safety net if the company does very badly and wishes to reopen the proceedings to change its price cap. These myriad complexities have resulted in a continuing high level of transactions costs for the regulatory process in the United States, as noted by KSW. Pure PCR, by contrast, mimics a competitive market in that the company can keep what it earns for the period of the price cap whether earnings are high or low.

Other devices have been touted as incentive regulation with attractive efficiency properties similar to PCR including "Revenue Caps" (RC).[12] An RC allows the total revenue of the firm to increase by some index of prices. It may also incorporate increases in total revenue to reflect customer growth. RCs have been employed in the United States in the electric

7 RPI is the retail price index, the British equivalent of the CPI in the United States. "Pure" PCR in the United States would be CPI - X.

8 The program also extended to "competitive" industries, including oil (BRITOIL), buses (National Bus Company), shipbuilding (British Shipbuilders), aircraft engines (Rolls Royce), and steel (British Steel). In none of these cases did PCR apply.

9 Even the notation in the water industry in England and Wales for PCR is slightly different, with the standard RPI - X being replaced by RPI - X +Y = RPI + K, where Y is the allowance made for increased capital investment.

10 KSW cite only 11 States where pure PCR applies.

11 Lyon (1996) makes a similar point, arguing that the uncertain potential for efficiency improvements makes sharing plans more efficient than pure PCR.

12 In spite of their frequent use in practice, claims that RCs have efficiency properties similar to PCR are specious as we have recently argued (Crew and Kleindorfer 1996).

utility industry but avoided in the United Kingdom except for the National Grid Company, whose current status, including its regulation, is in the process of change.[13] In principle, an RC may encourage cost economy or internal efficiency, since the firm can keep the difference between its capped total revenue and its total costs. However, as we argue elsewhere (Crew and Kleindorfer 1996), RC schemes can be damaging to efficiency and might be more appropriately termed "disincentive" regulation. Crew and Kleindorfer (1996) show that where the incumbent can freely set output, it will do so in a manner which may drive price above the monopoly level. We will not belabor the details here. Suffice it to say RCs are an artifact of monopoly, destroy the engine of sales that drives competition, do not promote efficiency, and should be abolished in electric utility regulation.

Given these comments on the incentives for RCs to cause output restrictions and the strength of the application of PCR in the United Kingdom, the use of RCs for the National Grid Company (NGC) deserves some brief comment. NGC's revenues during the 1990-1995 were capped for its regulated (i.e., bulk power) transmission services. The RC was set initially for NGC by considering the required ROI for NGC's net asset base at the beginning of the RC regime and translating this, with operating and maintenance expenses, into a revenue requirement. NGC does not play a major role in determining the level of output of the service provided (which is determined primarily by competition and market interactions between generators and demand centers). Thus, assuming stringent service quality monitoring, capping total revenues arguably provides incentives for NGC to minimize costs for which it is responsible (including ancillary generation services, congestion costs, and other costs associated with bulk power transmission service).[14] It is important to note that the reason why RCs may not significantly distort the transmission service market in this case is that output decisions (in terms of, say, kWh-miles) are largely beyond the control of NGC, at least in the short run. Thus, the output distortions noted earlier for the RC-regulated firm are not a major issue here. Nonetheless, it would be preferable to define NGC's output more precisely in terms of value-adding services it provides and use this service-based definition of NGC's operations as a basis for applying PCR or similar incentive regulation rather than an aggregate RC, which masks rather than clarifies the detailed value added of the company's service offerings. Such service-based incentive regulation would promote selling more and better services to customers rather than focusing on maintaining the asset base of the company (or whatever else was being used as the primary basis for setting the RC).

One of the major features of incentive regulation in both the United States and the United Kingdom has been the limited role played by economic theory. Where economic theory was employed, it was often misapplied. Practical decisions have been made with little regard to economic theory. A case in point is the RC. Even in PCR, practice departed from theory dramatically. The United Kingdom did not by any means fully adopt the original Littlechild (1983) proposal. He argued that the price cap should apply only to the monopoly services.

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13 NGC was owned by the distribution companies (RECs). In November 1995, the RECs were required to divest themselves of ownership of NGC. Simultaneously, NGC shares began to be publicly traded in the London stock market. For a description and analysis of the situation in the United Kingdom power sector, see Newbery (1995).

14 Of course, it is critically important to assure that the transmission service provider, NGC in this case, actually is responsible for all transmission-related costs. Otherwise, RC will encourage NGC to minimize only that portion of total transmission costs which show up on its income statement.

British Telecommunication's (BT) price cap extended way beyond that to include even international long distance.

In the United States, economic theory was misapplied with the effect of obfuscation of the issues. The basically simple idea of the X factor was replaced by the notion of the "productivity offset," particularly in telecommunications.[15] The economic clothing surrounding the productivity offset was such that regulators bought into the concept. The idea was that the X factor, instead of being considered nothing more than the real reduction in prices to be provided to the monopoly customers, was coupled directly with the productivity growth of the company. Prices would rise not by the CPI minus the X factor but by the CPI minus the productivity offset, where the productivity offset was intended to reflect the productivity of the firm. The company would typically hire a firm of consulting economists to measure the company's recent record of productivity (measured in terms of total factor productivity, TFP). It would then, by a process of extrapolation, argue, for the period of the price cap, that the X factor (in this process called the productivity offset) should be at approximately the level of TFP measured by the consultant's study.[16] In some cases, the argument was for an exact one-to-one relationship between historical productivity and the X factor.[17]

In the United Kingdom, by contrast, there was no direct coupling of the X factor with a productivity offset.[18] In the case of BT, the X factor started at 3% in 1984 and was raised to 7.5% in 1993 by Oftel, the United Kingdom regulator (see KSW), and BT continues to prosper! How much better would BT have done if it had been able to enlist the services of consulting economists and convince Oftel that the X factor should be set equal to the productivity offset! Although the practice of setting the X factor based upon the productivity offset is rather widespread, it is not the best practice, given our knowledge of incentive regulation in 1995. Setting the X factor involves several factors other than the productivity offset, as we will now discuss.

PCR offers considerable advantages compared to ROR where the incumbent is facing competitive entry. It offers the freedom to adjust prices promptly in response to changing economic conditions or actions by competitors. This is particularly true if the price-cap index that the company uses is of the standard Laspeyre variety. Even if the company's regulated product line is divided into various baskets, each subject to a price cap, the company still has considerable flexibility in pricing.[19] The flexibility afforded to the company in employing a price index is considerable, potentially allowing the company to price according to Ramsey or profit-maximizing principles according to inverse elasticities.[20]

15 In view of the objective of establishing the notion of a productivity offset, most of the recent studies of productivity have been concerned with United States telecommunications. An interesting recent example of a productivity study in electricity may be found in Ansar (1990). Her paper is interesting in its attempt to present a true historical record and does not draw unwarranted implications for regulation.

16 The measure of TFP derived is the percentage by which the rate of growth of company or industry differential exceeds the average for the whole economy.

17 The method used by the FCC also takes into account any input price advantages the industry has over the general economy (the input price differential).

18 See Beesley and Littlechild (1989) for a discussion.

19 Law (1995) provides a detailed examination of the problem of setting up price-cap baskets, including some illustrative examples.

20 The situation is somewhat complicated concerning whether prices will actually be Ramsey optimal in the

If measurements of TFP were entirely accurate and not subject to any controversy whatsoever, we would still argue against the use of the productivity offset in setting the X factor. Without going into detail, there are two ways of measuring TFP based upon marginal cost weights or revenue weights. If the latter is used and economic profits exist, the TFP measured will be distorted. Moreover, where economic profits exist, even when the X factor exceeds the "true" rather than the measured value of TFP, the company can still increase its profits. This is particularly apparent when real growth in demand or inflation are present. Take a simple two period example.

Example

We assume that the X factor is set so that profits in the second period are a fraction A of profits in the first period, with $0 \leq A \leq 1$. Then profits in the two periods are related by the following equation:

$$A(R - C) = R(1 + g - X) - C(1 + g - TFP) \tag{1}$$

If zero economic profits exist ($R = C$), then from (1) $X = TFP$ (the X factor is equal to the productivity factor), whatever the growth factor, g. In general, the X factor that solves (1) is given by

$$X = \left(1 - \frac{C}{R}\right)(1 - A + g) + \left(\frac{C}{R}\right)TFP \tag{2}$$

a convex combination of $(1 - A + g)$ and TFP, with the weights determined by C/R. Some examples of the effects of supernormal profits ($R > C$) and different growth rates on the profit-neutral X factor ($A = 1$) and an example of one profit-reducing X factor (with $A = .5$) are given in table 1.

As long as X is set between the level of the TFP column and the X (A=1) column, the firm can increase its level of supernormal profits. Thus, it is possible for the X factor to be set significantly above true TFP and for the company still to increase its profits, provided that either supernormal profits exist or demand is growing. Thus, it may not be too surprising that BT still continues to prosper despite its high X factors.

Note that the above logic is consistent with the existence of X-inefficiency. Consider the typical case in which the firm is not earning its full economic profits $R - C$ as reflected in (1), but rather some lower level of profits $R - C'$, with $C' > C$, the difference a result of X-inefficiency. In this case, considerable judgment must be exercised in setting the X factor. Otherwise the resulting PCR could be very generous for the company.[21] To illustrate some of the common pitfalls, one could estimate TFP on the basis of historical data and underestimate, therefore, the potential TFP for the future under a more flexible regulatory regime, such as PCR. Substitution of this lower estimate of TFP in (2), ceteris paribus, would clearly lead to a lower X factor and higher profits. Similarly, if C' (which is actually observed) rather than C were used in (2), the resulting computed X factor would also be too low (in the usual case in which $1 - A + g > TFP$) for the profit objectives and growth scenario embodied

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price-cap regulated company. Neu (1993) and Abbott and Crew (1993) have shown that, over time, PCR prices do not necessarily converge to Ramsey prices.

21 This was recognized somewhat in setting the X factor, in that a 0.5 "consumer dividend" was added to the productivity offset.

Table 1

C/R	*g*	*TFP*	*X (A = 1)*	*X(A = .5)*	*X(A = 0)*
0.9	0.1	0.01	0.019	.069	0.119
0.9	0.1	0.02	0.028	.078	0.128
0.9	0.1	0.03	0.037	.087	0.137
0.9	0.15	0.02	0.033	.083	0.133
0.9	0.2	0.02	0.038	.088	0.138
0.9	0.2	0.04	0.056	.106	0.156
0.8	0.2	0.04	0.072	.172	0.272

in (1). Finally, if revenue growth, g, under the more flexible PCR regime were underestimated (using historical estimates), the resulting X factor would also be too low. Clearly, if all of these errors were committed simultaneously, a very low X factor, relative to target profits, would result. This historical approach, with all the attendant errors, is frequently employed in practice.

We see that setting the X factor involves a number of issues beyond productivity. The United Kingdom approach implicitly recognizes this in that the X factor appears to be set based upon judgement. (See Beesley and Littlechild (1989).) It is not directly coupled with TFP in the way that it is in the United States. The ability to price more flexibly, the ability to retain some or all of the benefits of more efficient operation, plus the underlying arithmetic properties of price indices and profits, mean that setting the X factor involves much more than a simple coupling with TFP. In particular, if historically extrapolated TFP is used to "estimate" the X factor, this will underestimate the benefits of PCR arising from flexibility and revenue growth.[22] Moreover, given the measurement problems with TFP in regulated industries, the direct coupling of TFP to the X factor may focus the debate on the size of the X factor too narrowly on TFP measurement issues, rather than on the broader issues of revenue growth and reducing X-inefficiency.

A major issue in incentive regulation is commitment. If a company is concerned that the regulator will penalize it at the end of or even during the price-cap period if it is successful, it may not pursue efficiency as strongly as implied by the apparent incentives of PCR. Thus, the notion that the regulator will not renege on the terms of PCR is very important for efficiency to be achieved, as numerous writers have argued, for example, Laffont and Tirole (1993). Thus, given the importance of commitment on the part the regulator to the successful operation of PCR, we would expect that a concern for achieving commitment would be apparent in the practical application of incentive regulation.

In the United States and in the United Kingdom, the concern has taken different forms. In the United States, there has been an implicit recognition that regulators have limited incentives, let alone ability, to commit. This has manifested itself in devices such constraints on earnings, sharing rules, agreements about "infrastructure," and the like, as analyzed in KSW, Lyon (1994; 1996), and Weisman (1994). Such devices provide sharing of gains to ratepayers and, therefore, might be seen to be less vulnerable to reneging by the regulator if the company does well. In addition, such devices, in limiting how well the company can do, make the regulator less likely to renege. While ostensibly lowering the power of the

22 This same problem would apply to studies of productivity performed by independent researchers or regulatory agencies, such as the FCC.

incentives for efficiency in pure PCR, such restrictions, at least partially, avoid the inefficiencies arising from failure of commitment on the part of the regulator. Similarly, the coupling of the setting of the X factor with TFP might also be seen as a way of making commitment less critical. By placing an upper bound on X the company is placed under less pressure and, as long as it is confident that the coupling will remain, is less concerned about regulatory reneging through raising the X factor.

Raising the X factor is not a trivial concern, as it is precisely this method that the United Kingdom regulators have employed when companies have reported sustained high earnings. Sawkins (1996) briefly describes the recent actions of Offer, the electricity regulator, in the United Kingdom in setting prices and X factors. Offer set price caps and X factors in August 1994 only to reset them again in March 1995 in response to public pressure. This is just the kind of behavior that is at the heart of the commitment problem.[23] However, it has apparently had little obvious impact on the market value of UK utilities, as witnessed by share prices on the exchange and the fact that United States utilities and others have been acquiring United Kingdom electric distribution companies.

3. Implications for the Future of Incentive Regulation

KSW argue: "There is no evidence that incentive regulation has led to streamlined regulatory proceedings. Strong evidence that incentive regulation has reduced the costs of providing telephone service has not yet materialized. Thus, it would seem premature at this point to conclude that incentive regulation has been an overwhelming success." Their negative assessment, in the United States context, could be explained by noting the attenuated and convoluted way PCR and incentive regulation have been applied. While the application of PCR in the United States may not have been an overwhelming success, the same conclusion does not apply to the United Kingdom, where the reforms were more dramatic with privatization and PCR being adopted simultaneously. In both cases, of course, it is difficult (as KSW note) to separate the effects of incentive regulation from other simultaneous changes in competition, ownership, and regulation. Despite these complications, the question still remains as to what lessons can be learned from experience in both countries and what are the implications for policy.

Devices that masquerade as efficient incentive regulation should be abolished. In the case of one of the most egregious of these, Revenue Caps, this may happen sooner or later as pressure on electric utilities increases from the opening up of their generation business to competition. However, the power of environmental groups and others favoring RCs is not trivial, so we should not expect instant repeal of such devices for inefficiency.

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23 The FCC is currently considering a number of alternative approaches to setting the X factor, for example, a yardstick approach. See *Second Notice of Proposed Rulemaking in CC Docket No. 94-1, Further Notice of Proposed Rulemaking in CC Docket No. 93-124, and Second Further Notice of Proposed Rulemaking in CC Docket No. 93-197*, September 14, 1995 and September 20, 1995 and *Fourth Notice of Proposed Rulemaking*, September 27, 1995. If a yardstick approach were employed, for example, providing for an adjustment of the X factor every five years, this might partially alleviate the commitment problem, while at the same time encouraging improved performance. Detailed discussion on this point is beyond the scope of this paper.

The X factor needs to receive more attention. As we argued, TFP should no longer take the front seat in setting the X factor in the United States. It needs to be clearly recognized that setting the X factor requires considerable judgement. It is set by means of a bargaining game between the regulator and the company, similar in some respects to determination of allowed ROR in cost of service regulation. TFP may have a role of a lower bound in the bargaining game to set the X factor. If it is set too high, it results in a confiscation of the company's property, which is not only inequitable but inefficient, if the regulator is at all concerned with the maintenance of the infrastructure. Setting it too low fails to put enough pressure on the company to make it strive for efficiency. In view of the judgement required to set the X factor and in view of the asymmetries of information, in that the company has better information in determining the X factor than the regulator, an alternative is to allow the company a more active role in setting the X factor.

One approach to company choice of the X factor would be for the regulator to develop a menu from which the company would then choose. An early proposal of this sort is articulated in Crew and Kleindorfer (1992), who propose a menu-driven tradeoff structure between the level of the X factor and the rate of capital recovery. The menu is designed so that consumer welfare is held constant across menu alternatives, including a base case alternative that specifies an X factor (and possibly other regulatory parameters) based on (1) above. By revealed preference, company welfare is improved at their selection, and, thus, Pareto improvements can be implemented by allowing the company some increased flexibility in choosing from such a menu. Development of such revelation mechanisms is somewhat involved, however. In the Appendix, we sketch another welfare-improving menu structure which presents the company with a tradeoff between the level of the X factor and the share of the profits (denoted $\alpha(X)$) that the company is allowed to retain when profits exceed some nominal level (which in our example is based on an allowed ROR). We illustrate this approach below with an example, based on the sharing function in (A6) of the Appendix with $X_0 = 5\%$ and $X_s = 9\%$:[24]

X Factor Chosen by the Company[25]	Sharing Factor $\alpha(X)$ for Excess Profits
5.0%	20%
6.0%	40%
7.0%	60%
8.0%	80%
9.0%	100%

In this example, we suppose that the regulator sets a base case X factor of 5% following the logic of (1)-(2). If the company chose 7% as its X factor and achieved a rate of return of, say, 2% over its allowed rate of return, then it would keep .6 x 2% or 1.2% of the excess and would return in the form of a Z factor adjustment to the price cap, applied to all baskets

24 These figures are solely for the purpose of illustration and are not intended to be applied to any real-world industry.

25 Note that the X factor and the sharing percentage would apply for the period of the price cap and would not be subject to change by the company or the regulator baring force majeure.

proportionately, the ratepayers' share of .4 x 2% = 0.8% (times the end of year rate base K for the year in which the excess had been earned).

The reader should note that while the proposed scheme provides some benefits in motivating the company to analyze its earnings opportunities, whether through cost reductions or service enhancements, the scheme does not remove the problems of asymmetry in information between the company and the regulator. In particular, the regulator still has the responsibility for understanding and designing the menu structure $\{X, \alpha(X)\}$. If the regulator chooses an inappropriate menu structure, the company will simply choose the regulator's minimum X_0, even when some other menu structure might have induced the company to choose a higher X factor. Thus, the scheme proposed here does not remove from the regulator and other interested parties the responsibility for determining a good benchmark X_0 and for assessing a reasonable range of attainable X factor reductions. This is similar to the menu-driven asymmetric information results of Laffont and Tirole (1993). The difference here is that we do not begin with the much stronger assumption that the regulator knows the distribution of unknown parameters (typically those of the cost function) of the regulated firm.[26] Thus, the scheme presented here is implementable, and it clearly provides some motivation to the company to assess its own possibilities for providing increased dividends to ratepayers, while still making profits. In the spirit of incentive regulation, it also has the potential for reducing transactions costs associated with bargaining and, possibly, for increasing regulatory commitment. This proposal is, in a sense, an attempt to reconcile some of the conflicts between the United Kingdom and the United States approaches to incentive regulation, by providing strong incentives to reduce X inefficiency while economizing on transactions costs through regulatory mechanisms based on self revelation. As with other implementable incentive regulation, this proposal explicitly relies on the judgement of the regulator.

4. Summary and Conclusions

This paper has reviewed the approach to incentive regulation in the United Kingdom and the United States. The United Kingdom approach has typically relied on pure PCR, incorporating much sharper incentives for efficiency and lower transactions costs, but it makes the company more of a hostage to the regulator. The United States approach, which is grounded or even mired in the legal system, gives up efficiency incentives in an attempt to avoid making the companies the hostages of regulatory reneging.[27] The papers in this Issue illustrate the broad scope of incentive regulation, from the purer forms of PCR to a number of variations and mixtures of PCR with other forms of regulation. The interesting theoretic results and the importance of achieving practical solutions in incentive regulation underscore the importance of the problems and approaches raised in this Issue.

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26 Although note that x_{max} and therefore, in part, also $\alpha(X)$ is still set subjectively, so that the mechanism we propose reduces but does not eliminate the scope for subjective assessments in the design of the regulatory mechanism.

27 In so doing, it might also help preserve some residual market power. However, this is beyond the scope of our current discussion.

Appendix: A Mechanism for X-Factor Revelation

In the implementation of price caps, there is frequently considerable controversy surrounding the choice of the X factor. This appendix explores the issue of providing incentives to a utility, hereinafter "the company," under price-cap regulation to select (or reveal) an appropriate X factor. The company already receives some benefits from price caps, in the form of freedom from some of the traditional demands of regulation, including increased flexibility for pricing and new service offerings. In return, the company accepts the discipline of providing guaranteed benefits to ratepayers through the X factor. The issue we pose here is the approach a regulator should take to the setting of the X factor. We propose that the regulator should set a benchmark X factor which is the lowest X factor acceptable to the regulator, but that the company should have the opportunity to choose a higher X factor if the company sees opportunities to share in the benefits of so doing.

The approach we propose is as follows. If the company chooses a higher X factor than the regulator's minimum requirements, it is rewarded by being allowed to keep a higher fraction of any excess profits above a base return level. The rationale for this approach is that the company has better information on its potential for cost reduction and other profit drivers than the regulator, or any outsider. Thus, providing incentives for the company to reveal some of this information seems a better alternative to simply mandating an X factor. This follows the tradition of information economics which recognizes the second-best nature of institutional designs arising under conditions of informational asymmetry.[28]

To avoid increasing regulatory transactions costs, we propose a simple scheme of sharing excess profits between the company and its ratepayers. Essentially, we propose using the rate of return determined at the initializing of the price cap as the trigger level for sharing throughout the price cap regime. Sharing would be accomplished in all years but the final one by adjusting the company's price cap index by a Z factor adjustment in the following year. In the final year of the price cap, adjustment would be made as part of the re-initialization of the price cap if price caps are continued beyond the initial price cap period. If not, then the company keeps all of the profits it earns in the final year.

We model a company's gross earnings before payments to capital providers and taxes in a particular period, say a year. When these earnings exceed a benchmark level, as determined by a specified allowed rate of return, a share of these are returned to the ratepayers in the following year by a Z-factor adjustment. We will express the incentive system in terms of rates of return, but with the appropriate translation, the reader is free to think of this in terms of monetary earnings, if desired. We use the following notation.

Notation:

X = *the X factor in the price cap index;*

X_0 = the minimum X factor acceptable to the regulator;

s = allowed rate of return as determined in the initialization of the price-cap regime;

28 For a recent discussion of research and policy issues related to incentive regulation, see Crew (1994). For a discussion of information economic issues in the context of regulation, see Chapter 5 of Crew and Kleindorfer (1992).

$X_s =$ the maximum X factor consistent with the company's earning at least its allowed rate of return s;
$r(X) =$ rate of return achieved by the company, a function of the X factor;
$K =$ rate base for the year in question;[29]
$\alpha(X) =$ amount of "excess profits" earned by the company which the company will be allowed to keep; the function $\alpha(X)$ is a sharing function set by the regulator;
$z^+ =$ Max $[z, 0]$ for any real number z.

Using this notation, we can express accounting gross profits (before payments to capital providers and taxes) as

$$G(X) = K\,(Min[r(X), s] + \alpha(X)\left[r(X) - s\right]^+). \tag{A1}$$

We assume the following properties for the functions $r(X)$ and $\alpha(X)$:

Assumptions:

$r(X)$: The company return function r(X) is continuous, strictly concave, and decreasing for $X \geq 0$.

$\alpha(X)$: The regulator-determined sharing function $\alpha(X)$ is nondecreasing everywhere, continuous except possibly at X_0, concave and strictly increasing on $[X_0, X_s]$. Thus, α satisfies[30]

$$\alpha(X) \in [0, 1]; \quad \alpha(X) = 0, \quad \text{for all } X < X_0$$

$$\alpha(X_0) \geq 0; \quad \alpha_X(X) > 0, \quad \text{for all } X \in [X_0, X_s]. \tag{A2}$$

From these assumptions, we see that the (achievable) return function decreases continuously as X increases; the sharing function α is nondecreasing and continuous, except possibly at X_0, where there may be a jump in α if $\alpha(X_0) > 0$.

Proposition: Suppose the above Assumptions hold, and suppose $r(X_0) > s$ and that $r(X_s) \leq s$ for some $X_s > X_0$. Then there is a unique $X^* \in [X_0, X_s]$ such that

$$X^* \in arg \max_{X \geq 0} G(X). \tag{A3}$$

In particular, X^* would be freely selected by a profit-maximizing company from the menu $\{X, \alpha(X) \mid X \geq X_0\}$.

Proof: From the definition of G and our assumptions on α and r, $G(X) \leq sK$ for $X < X_0$ and for $X > X_s$. Next note that $G(X_0 + \delta) > sK$ for sufficiently small $\delta > 0$, since $r(X_0) > s$ and $\alpha(X)$ is strictly increasing (and therefore positive) in the interior of $[X_0, X_s]$. Thus, any solution to $Max\{G(X) \mid X \geq 0\}$, if one exists, must be in the interval $[X_0, X_s]$. Moreover, by continuity and compactness, G has a solution on $[X_0, X_s]$. To see that this solution is unique, we finally note that G is strictly concave on $[X_0, X_s]$. To see this, note from (A1) that in this interval G is of the form

29 Note that this rate base would be the rate base at the end of the year in question.

30 We use subscripts to denote derivatives; e.g., $\alpha_X(X) = d\alpha(X)/dx$. We assume the necessary derivatives exist, but a longer argument would establish the same results using just continuity.

$$G(X) = K([1 - \alpha(X)]\, s + \alpha(X)\, r(X)), \quad X \in [X_0, `X_s], \tag{A4}$$

i.e., $G(X)$ is a convex combination of x and $r(X)$ in this interval, with the sharing function determining the weight on $r(X)$. From this, strict concavity follows directly. For example, assuming that the requisites derivatives exist, we compute G_{XX} as

$$G_{XX}(X) = K\Big([r(X) - s]\, \alpha_{XX}(X) + 2\alpha_X(X)\, r_X(X) + \alpha(X) r_{XX}(X)\Big); \quad X \in [X_0, X_s], \tag{A5}$$

each term of which is negative (with $\alpha(X)r_{xx}(X)$ strictly negative), so that the usual second-order sufficient condition for (strict) concavity is satisfied. Thus, X^* in (A3) is unique, and our proposition is proved.

The above proposition thus shows that the company will, if anything, have an incentive to select a higher X than the regulator's minimum X_0, provided that the company can earn its rate of return at a higher X than X_0. Thus, the scheme proposed will, if anything, provide Pareto improvements for the company and ratepayers. At worst, the company will select X_0. If the company selects a higher X factor, then clearly the company is better off by revealed preference. Ratepayers are also better off since they are now guaranteed a higher dividend.

There are several degrees of freedom in the specification of the sharing function $\alpha(X)$, and we now discuss these. We will do so for a particular class of sharing functions that has the appropriate incentive properties in general. The class is of the form:

$$\alpha(X) = \frac{X(1 - \alpha_0) + \alpha_0 X_s - X_0}{X_s - X_0}, \quad \text{for all } X \in \left[X_0, X_s\right], \tag{A6}$$

where $\alpha_0 \geq 0$ is the sharing fraction for the company if it selects X_0 as the X factor, and where X_s is the regulator's best estimate of maximally attainable X factor reductions consistent with the company's earning a fair rate of return. This sharing function thus takes the value α_0 at X_0 and increases linearly to 1 as X increases to X_s. Note that if the company chooses $X = X_s$, then it keeps all excess returns. This is consistent with the definition of X_s.

The rationale for setting $\alpha_0 > 0$ is that it provides the company with an incentive to achieve profits when these are attainable, rather than engage in waste, even when X_0 is chosen. Note that a share (namely, $1 - \alpha_0$) of these gross profits will go to the ratepayers. In particular, this scheme assures at least weak welfare improvement (and strong improvement if the company chooses any $X > X_0$, since in this case consumers will see guaranteed greater real price decreases than under the base case). Note that the company is at least as well off by revealed preference.

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Appendix D8-3

THE REGULATION OF PRIVATIZED MONOPOLIES IN THE UNITED KINGDOM

M.E. Beesley and S.C. Littlechild, 1989

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The regulation of privatized monopolies in the United Kingdom

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and

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This article examines the experience in the United Kingdom with the regulation of privatized monopolies. Its conclusions are (1) that there are significant differences between RPI − X *(or price-cap) and U.S. rate-of-return regulation, which provides greater scope for bargaining in the former system; (2) that U.K. regulators have taken seriously their duty to promote competition, but that the existing economic literature is of limited help in this task; (3) that price regulation is likely to be more effective where technology is changing slowly and/or where there are many firms in an industry, whereas the promotion of competition is indicated where technology is changing rapidly; and (4) that the case for* RPI − X *price-cap, rather than rate-of-return regulation, is strongest in telecommunications, gas supply, and electricity supply and least strong in gas and electricity transmission grids.*

Since 1979, the Conservative Government has transferred over two dozen public enterprises into private ownership. Most of them previously operated in more or less competitive industries, but three of the largest—namely, British Telecom (BT), British Airports Authority (BAA), and British Gas (BG)—had market shares approaching 100% for their core activities. These three companies now operate under licenses containing many obligations and constraints. Independent regulatory authorities, each headed by a Director General, monitor and enforce compliance with license conditions. The impending privatization of the water and electric industries will follow a similar pattern, although in these two industries there will be a number of successor companies rather than a single major one. Thus, in the U.K. there is now a set of five major privatized industries which (in the U.S. context) would normally be thought of as regulated utilities.

The statutory duties of the regulators include protecting the interests of producers (licensees), of consumers of various kinds, and of employees and third parties (e.g., environmental concerns). The wording varies but, for present purposes, three main objectives may be identified in the respective privatization Acts: (1) to ensure that all reasonable demands are met, and that licensees are able to finance the provision of these services; (2) to protect the interests of consumers with respect to prices and quality of service; and (3)

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to enable or promote competition in the industry. Strictly speaking, the duties of the regulator are not a direct obligation to achieve the stated objectives, but rather require the regulator to carry out his statutory functions in the manner which he believes is best calculated to achieve these objectives.

Economists may find it helpful to analyze privatization as the instrument of change in a cost-benefit appraisal. The privatization acts, and in particular the duties of the regulators, may be interpreted as consistent with a formal aim of maximizing the present value of expected net benefits to consumers plus producers, subject to a minimum profit condition and to various constraints on the distribution of benefits to ensure Pareto efficiency (i.e., no major interest group is to be made worse off). The problem then faced by each regulator is to interpret this general criterion and make it operational. In particular, the regulator has to balance the interests of present and future consumers, both against each other and against the interests of present and future producers.

This article examines the experience of the United Kingdom with regulation of privatized monopolies. In particular, we consider: (1) whether the form of price control adopted is significantly different from U.S. rate-of-return regulation and how far this constitutes an advantage; (2) how regulators have tackled their duty to promote competition and what mode of economic analysis is most appropriate for this; and (3) under what circumstances each of the two main regulatory duties is likely to be performed most effectively and what this implies for government policy.

2. Price control

■ Rate-of-return regulation is well established in the U.S. There have been numerous variants across jurisdictions, across industries, and over time, but for present purposes the key features of "traditional" rate-of-return regulation may be characterized as follows (see Phillips, 1969).

The regulated company files a tariff when it wishes to revise its prices. For an agreed test period ("frequently the latest 12-month period for which complete data are available." Phillips, 1969), the company calculates operating costs, capital employed, and cost of capital. The regulator audits these calculations and determines a fair rate of return on capital employed. These data plus assumptions about demand are used to calculate the total revenue requirement. This determines the *level* of the tariff. The *structure* of the tariff has to avoid unfairness and unjust or unreasonable discrimination. The tariff therefore has to be approved on a line-by-line or service-by-service basis, which typically requires the allocation of common costs on the basis of, for example, output, direct costs, revenues, etc. An approved tariff generally stands until the company files to change it, usually on the grounds that the achieved rate of return has become inadequate.

When making its plans for privatizing British Telecom (BT), the Department of Industry's original intention was to adopt a modified rate-of-return regulation. After further discussion and investigation, however (Littlechild, 1983), a control on prices, or price cap, was finally adopted and variants of it have been used for the other privatized utilities.

The key features of this price control are that, for a prespecified period of four to five years, the company can make any changes it wishes to prices, provided that the average price of a specified basket of its goods and services does not increase faster than $RPI - X$, where RPI is the Retail Price Index (i.e., the rate of inflation) and X is a number specified by the government. At the end of the specified period, the level of X is reset by the regulator, and the process is repeated.

□ **Rate of return versus $RPI - X$.** The pros and cons of rate-of-return regulation versus $RPI - X$ and other schemes have been frequently discussed (e.g., Littlechild (1983), Vickers and Yarrow (1988), Johnson (1989)). Briefly, the main arguments for $RPI - X$, as originally spelled out in the context of privatizing BT and subsequently repeated in other cases, are three-fold. First, *RPI* − *X* is less vulnerable to "cost-plus" inefficiency and over-capitalization (the "Averch-Johnson effect"). Because the company has the right to keep whatever profits it can earn during the specified period (and must also absorb any losses), this preserves the incentive to productive efficiency associated with unconstrained profit maximization. Part of this expected increased efficiency can be passed on to customers, via the level of *X*. Prices are therefore lower than they would be under rate-of-return control, without producers being worse off. Second, *RPI* − *X* allows the company greater flexibility to adjust the structure of prices within the basket, and in principle there is no constraint on prices outside the basket. This is of particular importance where, as with British Telecom, initial prices were thought to be considerably out of line with relative costs, yet "optimal" prices could not be immediately determined and achieved because of inadequate knowledge of costs and demands, as well as political constraints on speed of adjustment. Third, *RPI* − *X* is simpler to operate by the regulator and the company. It is more transparent and better focused on the parameter(s) of greatest concern to customers, hence providing them with greater reassurance.

The main counterargument against the incentive and efficiency claim may be summarized as follows. The level of *X* must in practice be set, and repeatedly adjusted to secure a reasonable rate of return. If not, allocative inefficiencies will arise (from prices being out of line with costs), and there will be political pressures from company or consumers. If the criteria for revising *X* are left unclear, this will increase the cost of capital and/or discourage investment. Clear guidelines must therefore be laid down, or must emerge from precedent, for resetting *X*. These guidelines will have to embody an explicit feedback from cost reduction to (eventual) price reduction. This will negate the superior incentive effects claimed for *RPI* − *X*. Specifically, companies may believe that the short-term advantages of increased efficiency and lower costs will be more than offset by a tougher *X* and therefore lower prices in the next period, and may even induce an adverse change of *X* within the current period. In this view, *RPI* − *X* is merely a special form of rate-of-return control, embodying no significant net advantage over the U.S. approach on grounds of economic efficiency.

It is also questioned whether *RPI* − *X* involves as much price flexibility and transparency as claimed. It is further suggested that greater price flexibility may be a disadvantage rather than an advantage, since it allows cross-subsidization which is allocatively inefficient and may be used anticompetitively.[1]

The key questions to pose in this section are thus whether in practice *RPI* − *X* makes any difference to regulation and, if so, whether the differences are beneficial. Our aim is to assess how *RPI* − *X* has actually operated in the United Kingdom. We make no attempt to assess its potential effectiveness in or appropriateness for the U.S.

□ **Setting and resetting *X*.** In assessing these arguments, it is necessary to understand the procedures for setting and resetting *X*, and to appreciate the similarities and differences between them.

The *RPI* − *X* constraint is one of many conditions in the regulated company's license, all of which are initially set by the government. Unlike the other conditions, it has a limited duration, typically five years, and there is no formal constraint on the magnitude of *X* in any subsequent period. The regulator may modify any license condition at any time by agreement with the licensee. If the licensee does not agree, the regulator may refer the matter to the Monopolies and Mergers Commission (MMC) and has the authority to modify the

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[1] Other issues lie beyond the scope of this article. For example, it has been suggested that *RPI* − *X* may offer less incentive to maintain service quality (Vickers and Yarrow, 1988; Besen, 1989). The framework of regulation needs to be designed accordingly, and the acts and licenses do in fact reflect this consideration.

license if and only if the MMC finds the licensees to be acting against the public interest. (With certain exceptions, the licensee has no power to refer possible license modifications to the MMC.) Renewal of the $RPI - X$ constraint, whatever the level of X, is equivalent to a license modification.

The initial level of X is set by the government at the time of privatization, *as part of the privatization process,* whereas X is reset by the regulator *as part of the continuing regulatory process.* This has three important implications.

First, the initial level of X is set as part of a whole package of measures, whose parameters affect the costs, revenues, and risks of the regulated company. Some of these parameters pertain to the design of the price control itself, including the duration of the price constraint, its scope in terms of goods and services included, what costs (if any) are allowed to be "passed through" into prices, and whether the constraint is calculated on the basis of historical or expected performance. All these parameters are embodied in license conditions. Other parameters pertain to the wider regulatory framework, including what other noncommercial obligations or constraints are put on the company, what steps are taken to encourage or restrict competition, what policies are adopted towards suppliers, and so on. Both sets of parameters are fixed by the government more or less simultaneously in full acknowledgement of the interactions and trade-offs between them. They are gradually firmed up and made more precise in the run-up to privatization, culminating in the determination of certain key parameters, including X, prior to publication of the prospectus, a few weeks before flotation. (The striking price of the shares is determined later in this last period and will be heavily influenced by the anticipated changes in the stock market level to the flotation date.)

In contrast, the resetting of X takes place in a context where these parameters have already been determined. Admittedly they could be changed, and in practice some have been, but to make substantial and unexpected changes would have potentially adverse effects on the company's cost of capital and hence on prices to customers. Moreover, insofar as any proposed changes pertain to the company's license, if the company does not agree to the changes, the regulator may not wish to run the risk of an unsuccessful appeal to the MMC. There are thus fewer degrees of freedom in resetting X.

Second, the initial level of X is set by the government as owner of the company, whereas X is reset by a regulator who does not own the shares. The government as owner can choose, if it wishes, to take lower proceeds in return for, say, lower prices to customers. The regulator does not have that extra degree of freedom: any shift in favor of one interest group (such as customers) will be at the expense of another group (such as shareholders). The regulator is constrained by the expectations of shareholders and customers, which were established at privatization, and his discretion is limited to whatever range is deemed acceptable (or can be so presented).

The third difference between setting and resetting X, which reinforces the previous two, relates to the effect on the company's share price. In both cases the level of X will influence the share price via its effects on expected net revenue streams, so the stock market in fact decides the yield to shareholders. At the time that X is initially set, however, this effect has to be conjectured. It is not known with any certainty how potential investors will evaluate the company put before them. Nor is there any market valuation of the previous or alternative arrangements with which to compare it. After privatization, however, the views of investors are clearly reflected in the company's traded share price, with its accompanying dividend yield, price earnings ratio, relative risk factor β, etc. A *change* in the stock market's evaluation of the company, following any action by the regulator, in particular his revision of X, can be immediately observed in the change in share price. If the market regards the regulator's decision as favorable to the company (i.e., more favorable than expected), its share price is marked up and its cost of capital falls; the opposite happens if the decision is regarded unfavorably. The regulator cannot ignore this consideration in his decisions, and it reinforces the greater constraints on resetting X than on setting it initially.

To summarize, when setting X initially there are many degrees of freedom. X is just one of numerous parameters chosen simultaneously in the light of the political and economic tradeoffs involved. There is nothing unique, optimal, or mechanical about the initial choice of X. When X is reset, there are significantly fewer degrees of freedom. Nevertheless, there invariably *are* degrees of freedom open to the regulator.

The following two examples will illustrate the above procedures and provide further insights into the characteristics of the $RPI - X$ approach.

Setting X *for Manchester Airport.* The Airports Act of 1986 provides for economic regulation of "designated" airports. At privatization, the Secretary of State designated BAA's three London airports and specified $RPI - X$ regulation with $X = 1\%$. He also designated Manchester Airport, but delegated to the Civil Aviation Authority (CAA), as regulator, the task of designing Manchester's regulatory constraint. The Airports Act required the CAA, in turn, to seek the advice of the MMC.

Since Manchester Airport was not to be privatized, but was to remain in the ownership of The Manchester City Council, in important respects the considerations involved were different from those where X is set or reset for a privatized company. Nonetheless, there are useful insights to be obtained from the MMC report because it sets out in some detail its reasoning on $RPI - X$. (Note that the MMC in this context is an "advisor" to the regulator, not the regulator itself, and by convention the MMC's report is its only means of conveying that advice.)

The MMC recommended that $RPI - X$ be adopted rather than rate-of-return control, for the kinds of reasons given earlier. The Airports Act set the review period as five years, and the MMC was advised that the scope of price control had to comprise landing, parking, and passenger charges, but not baggage handling charges. The MMC exercised judgement on four main parameters apart from the level of X. It recommended

1) that there be a single basket for all three charges rather than (say) three separate baskets or additional subconstraints on prices;
2) that the formula be based on a "tariff basket" (as used for British Telecom), with weights reflecting revenues in the previous year rather than on a "revenue yield" (as used for BAA) involving predicted revenue per unit and a subsequent correction factor;
3) that no special allowance be made for passing-through costs associated with changes in (noneconomic) government regulation, except for three-quarters of any additional airport security costs; and
4) that the present levels of airport charges (which some users claimed were too high) were the appropriate starting point for the formula.

In proposing a level for X, the MMC's procedure was first to examine four important issues: future traffic growth, the timing and financing of capital expenditure (particularly the construction of a second terminal), the development of (unregulated) commercial income, and the scope for cost reduction and productivity increases. After exploring a range of alternative assumptions, it adopted those used by the company itself (except on 100% self-financing policy), albeit commenting that some of these assumptions were rather cautious. On the basis of the adopted assumptions, it used the company's financial model to make predictions, for each year over a five-year horizon, of four financial magnitudes (operating profit before and after interest and tax, net current assets and shareholders' funds) and five financial ratios (gearing or debt-equity ratio, self-financing ratio, interest cover, dividend cover, and return on capital employed). The MMC then "looked for a value of X which would give the necessary degree of protection to users of the airport while leaving the company in a financially sound position and able to carry through its capital expenditure plans." (See MMC, 1987.) It recommended that $X = 1\%$.

Note that the MMC approach was explicitly based on *future predictions,* and a central problem for the MMC was to decide what those predictions should be. It felt that Manchester's assumptions were often cautious, but had no firm basis for making alternative assumptions. (Over time, a regulator would aim to secure an independent source of information on these matters, and the CAA has begun to do so, as have the other regulators in their own areas. We discuss this point further below.)

This forward-looking approach also applied to the financial calculations. The rate of return on (historic) book capital was only one of nine financial projections and ratios that the MMC looked at. It was projected to decline steadily from the present 18.8% to 9.0% at the end of five years. The MMC merely commented that these rates of return were considered "consistent with our assessment of the company's financial soundness, which is also reflected in the other projections." (See MMC (1987).) Thus, in order to assess the future yield to shareholders, the MMC found it necessary to go beyond a single historic cost ratio.

The CAA proposed to accept the MMC's recommendations. Manchester Airport then appealed to the CAA, arguing for $X = 2\%$ (i.e., $RPI - 2$) and a revenue yield approach. Other interested parties also made representations. The CAA upheld $X = 1\%$, but granted Manchester Airport's request for revenue yield. The CAA report hints at the bargaining situation in which it found itself but, in giving its verdict, does not quantify (for example) the differential effect on future cash flows of revenue yield versus a tariff basket approach. (See Civil Aviation Authority (1988).)

Setting and resetting X *for British Telecom.* At a late stage in the privatization of British Telecom in 1984, three parameters remained to be determined: the contents of the "basket" (i.e., the coverage of the price cap), whether to allow unrestricted resale of BT's leased lines, and the level of X. The third parameter had clear implications for prices and proceeds, but so did the other two. Unrestricted resale would allow competitors to use low-priced BT circuits to undercut high-priced BT phone calls; this would mean lower prices, revenues, and proceeds. Restricting the basket to local calls and connection charges, for which the monopoly was thought to be strongest, would leave little scope for price reductions. Indeed, British Telecom argued that local calls and connections were already underpriced. On the other hand, incorporating inland trunk calls—where competition was pending, prices were already considerably in excess of costs, and technological prospects were for yet lower costs—would give scope for greater average price reductions across the basket as a whole. (International calls, though known to be highly profitable, were not a serious candidate for inclusion at that time, perhaps reflecting the government's unwillingness to provoke issues of international liberalization at a time when only the U.S. was clearly pursuing similar policies.)

There was considerable negotiation, involving a wide range of X's. (This has been repeated in subsequent privatizations.) The eventual outcome was a package comprising no resale, inland trunk calls in the basket, and $X = 3\%$. The detailed calculations on which this figure was based have not been published. (Nor, for that matter, have any of the calculations of other X's by government departments.) The offer price for BT's shares was set to ensure that there would be demand from a large number of small shareholders and employees. After flotation, the share price was duly bid up by institutional shareholders, who had excess demand at the offer price.

As BT's profits increased, the question was raised whether they were excessive, even though its prices were within the $RPI - X$ constraint. The regulator published an assessment of the appropriate rate of return for BT to earn, concluding that the then-observed level of 18% on book value was about right (Director General of Telecommunications, 1986). (For a debate on the adequacy of this assessment, see Beesley, *et al.* (1987) and Carsberg (1987).) BT, in fact, held its prices below the permitted maximum for two years. The regulator also commented on BT's changing price structure, suggesting that rebalancing between inland trunk and local call prices had gone far enough. His staff published an analysis of price structure based on Ramsey pricing (Culham, 1987), although this was viewed with caution by the regulator himself.

The resetting of X in 1989 was preceded by a consultative document (Director General of Telecommunications, 1988a) in which the regulator invited comments and suggestions for modification to the whole framework of BT's price control, such as substituting rate of return for $RPI - X$, using revenue yield instead of tariff basket, changing the coverage and duration of $RPI - X$, and so on. Each of these would have required a change in the license, and therefore allowed the possibility of a challenge by BT and reference to the MMC. An agreement was reached. The regulator reduced the duration of the subsequent review period from five to four years (to reflect the uncertainties involved and BT's own investment planning horizon), slightly extended the coverage of the price cap (to include directory services), and increased X from 3% to 4.5%. He rejected the options of including international calls in the basket, but indicated that he would keep this area under review. He gave no detailed explanation for his choice of X, beyond indicating that rate of return was the most important criterion, but not the only one. The other factor mentioned was the financing of investment. He stated that in determining X, he had considered the effect on growth in earnings and borrowing, as well as on rate of return. (Director General of Telecommunications, 1988b).

The regulator noted that he had taken some account of current cost accounting results. Perhaps a decision based entirely on such a valuation would have indicated higher prices and therefore a lower X, which would have been favorable to BT. In explaining his position, however, the regulator stated that current cost accounting should not be used as the sole basis of regulation unless it was also used as the main basis of reporting to shareholders. BT was evidently unwilling to do this. Nor did BT think it advantageous to challenge the decision on X, which would have meant submitting to an MMC investigation. As it happens, BT's share price did not move significantly after the announcement, suggesting that changing X to 4.5% did not alter the stock market's expectations of BT's future profit stream.

One may surmise that the regulator focused the issue of the future level of X on BT's prospective or possible gains in productivity. By making effective use of the degrees of freedom open to him in redefining the formula and of BT's unwillingness to challenge his decision, the regulator was able to get agreement to a higher X than would otherwise have been possible. He thus set a target for efficiency, which BT was constrained to follow; he did not base his judgement primarily on evidence of what had *previously* happened in the industry.

□ **Incentives and efficiency.** In light of these two examples, but also taking into account the experiences of the other industries, we may now address the argument on incentives and efficiency.

$RPI - X$ and rate-of-return regulation have certain common features. Both accept the need to secure an adequate return for the company's shareholders in order to induce them to continue to finance the business, without conceding unnecessarily high prices at the expense of customers. Nevertheless, there *are* significant differences between the two systems, which give $RPI - X$ a potential advantage with respect to incentives and efficiency.

First, $RPI - X$ embodies an exogenously determined risk period between appraisals of prices, whereas rate-of-return regulation makes the duration of this period endogenous. Admittedly, U.S. regulatory commissions have tended not to intervene when profits are increasing, provided that prices are not increased (Joskow, 1974), but the company can file for a new tariff whenever its performance diminishes, which may be quite frequently. This last is not possible in the U.K. The regulator can propose a modification of X within the risk period. BT's regulator considered doing this, but he decided not to. Apart from the disincentive effects, there would have been a risk of not getting MMC support for a contested license modification. BT's regulator also reinforced the concept of an exogenous risk period by reducing its duration from five to four years to limit the extent of uncertainty during the period and stressed that any midterm review should be limited to major unexpected events outside the company's control (Director General of Telecommunications, 1988).

Second, $RPI - X$ is more forward-looking than rate-of-return regulation. The latter tends to be based on historic costs and demands, with adjustments for the future limited (at most) to an adjustment for inflation or the extrapolation of historic trends.[2] In contrast, $RPI - X$ embodies forecasts of what productivity improvements can be achieved and what future demands will be and is set on the basis of predicted future cash flows.

Third, there are more degrees of freedom in setting X than are involved in rate-of-return regulation. The latter system does allow flexibility (e.g., on the basis of asset valuation, the definition of the rate base, treatment of work in progress, etc.) but it would seem difficult to change these decisions repeatedly. X is initially set in the context of negotiations about the whole regulatory framework, including the coverage, duration, and form of the price constraints, the extent of noncommercial obligations, the restrictions on competition, and the permissible rate of adjustment from inherited pricing policies. In resetting X, the regulator has fewer degrees of freedom, but nonetheless can modify (at least at the margins) any aspect of this framework and in practice has done so.

Fourth, in setting X the U.K. regulator has more discretion and less need to reveal the basis of his decisions than does his U.S. counterpart. The U.S. tradition is to place all evidence and reasoning in the public record. In the U.K., there is less pressure for due process. The U.K. regulator is deemed to be a person to whom public policy may be safely delegated, subject only to judicial review on the question of whether his actions are legitimate in terms of the act. In the U.K., neither governments nor regulators have given detailed reasons for their decisions on X. This reduces the basis for challenge (by company, competitors, or customers).

The consequence of these four differences—exogenous risk period, forward-looking approach, degrees of freedom, and less requirement to explain—is that there is greater scope for *bargaining* in $RPI - X$ than in rate-of-return regulation. The level of X can reflect negotiations with the company, not only about the scope for future productivity agreements, but also about other matters affecting the company's future, including the details of the price constraint formula, the rate at which competition is allowed to develop, the provision of information, and so on. In short, X may be thought of as one of several variables in a political and commercial bargaining process.

It is not suggested that U.K. regulation is conducted, or even perceived, primarily in terms of bargaining. Nor, on the other hand, is it claimed that there is *no* scope for bargaining in U.S. rate-of-return regulation. Spulber (1989), for example, explicitly characterized U.S. rate hearings as a bargaining process between consumers and the regulated firm. The hearings economize on the transaction costs of forming consumer coalitions and bargaining directly with the firms. The regulatory commission establishes rules for negotiation and mechanisms for the resolution of conflict, selects the issues that are open to debate, acts as arbiter and

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[2] "Commissions base costs upon a test year due to the need for certainty—the need to avoid unresolvable factual disputes that threaten lengthy proceedings, arbitrary decisions, and court reversals. Although last year's prices will differ from likely future prices, at least they are known. One thereby avoids what would be an endless and unresolvable argument about what future costs will probably be." (Breyer, 1982). "The Commissions have been hesitant to make future forecasts of consumer demand, often preferring instead to assume that the test period demand conditions will hold in the immediate future." (Phillips, 1969). Joskow (1974) noted that "a few commissions have begun to cautiously use 'projected' test year results, allowing companies to predict cost and demand conditions one or two years ahead," but this does not appear to have become standard practice. Automatic adjustment mechanisms are widely used, however (Joskow, 1974; Spulber, 1989).

"may select an outcome especially if bargaining does not yield a unique solution" (p. 270). Spulber also notes that "rates are often set *indirectly* through decisions on methods of estimating costs, demand, and rates of return" (p. 272). These insights are not inconsistent with our own assessment. Our claim here is simply that the U.K. approach offers greater and more direct scope for bargaining, with a correspondingly more active role for the regulator.

There is an important implication for incentives and efficiency. The exogenous risk period and the forward-looking approach mean that the company is not deterred from making efficiency improvements either by fear of confiscation *within* the period or by the belief that allowed *future* prices will simply be an extrapolation of past costs. The regulator can take an independent view of the scope for productivity improvements and can use the discretion and degrees of freedom open to him including the absence of a requirement to justify decisions in detail, to negotiate a better deal than would otherwise be possible.

Whether the difference between $RPI - X$ and rate-of-return regulation is significant depends on whether the regulator is able to use the additional bargaining power effectively. This depends upon the underlying scope for efficiency improvements and upon the extent and quality of the information available to him. (See Vickers and Yarrow (1988).) These factors will differ from one industry to another. We take up this issue in the final section of this article.

□ **Price flexibility.** Traditional U.S. rate-of-return regulation requires each price to be individually approved. Changing a price requires filing a new tariff. In principle, $RPI - X$ allows any price to be changed at any time, subject only to the price cap on the average price within the basket. The coverage of the price cap is approximately 37% of BAA's total revenue, 57% of BT's, 63% of BG's, and probably 95% or more of the water and electric companies. Again, in principle, there is no constraint on prices outside the basket.

In practice, the regulated companies are typically more constrained than this. BAA has subconstraints on its two major airports; the public electricity suppliers will have separate constraints on their distribution and supply activities; and BT gave a written undertaking (outside the license) to limit the rate of increase of residential line rentals to $RPI + 2$. The regulator has since added an additional constraint for BT's private circuits and brought directory services into BT's basket; nondiscrimination provisions have also been added for gas. There are also informal constraints: BT's regulator indicated that the rebalancing of trunk and local call prices had, in his view, gone far enough, with the threat of explicit control via modification of the license. There is always an incentive for a regulator to increase control by refining and extending the basket.

On the other hand, the rebalancing problem was in part attributable to the definition of BT's basket (which included competitive as well as monopoly services) rather than to the $RPI - X$ concept itself. As Johnson (1989) has suggested, a key task during each formal review is to redesign the basket(s) to reflect (changing) market conditions.[3] BT's regulator did not in fact press his concerns on relative prices and, in particular, did not adopt the Ramsey pricing philosophy examined by his staff. Any new contested constraint would, in any case, need MMC approval. In effect, the burden of proof is on the regulator to show cause why the rebalancing of prices should not occur. The opposite applies in U.S. rate-of-return regulation, where the burden is on the company to justify the price changes it proposes. There seems no doubt that $RPI - X$ allows greater pricing flexibility for the regulated company.

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[3] The possibility of a company cross-subsidizing competitive uncapped services out of monopoly capped services is frequently mentioned in the literature (e.g., Johnson (1989), Besen (1989), Spulber (1989)) but to date this has not been a major issue in U.K. regulatory experience.

Whether this flexibility constitutes an advantage or a disadvantage depends upon how much need there is for price flexibility (e.g., to reflect changing conditions), how much information is available to the regulator for determining prices in detail, and what other instruments are available for dealing with anti-competitive pricing (e.g., nondiscrimination provisions). Again, we return to these issues in the final section of the article.

□ **Transparency: cost pass-through and the *X*-formula.** As privatization has been extended from BT to other utilities, questions have arisen as to whether the simple $RPI - X$ constraint is appropriate for industries with different cost and demand structures. For example, should certain costs be passed through into prices, and should the price cap be based on historic or predicted parameters? Decisions on these questions have implications for profits and proceeds, consumer prices, and economic efficiency, as well as having an effect on transparency.

Cost pass-through. An essential feature of any price-control scheme is the provision to be made for costs which are considered outside the control of the regulated company's management. Several options are available. A simple $RPI - X$ constraint, based on expected costs, would expose the company to greater risk, thereby increasing the cost of capital and reducing proceeds. Setting a lower (less stringent) value of X would provide a greater margin against risk, but would imply higher prices for customers. Shortening the review period would reduce risk, but also would reduce the scope and incentive for cost savings; the cost of review would also be incurred more frequently.

The fourth possibility is to allow increases in specified costs to be passed through to customers as they occur. This does not eliminate the risk, but simply transfers it from company to customer. It therefore reduces the incentive of the company to seek lower cost or less uncertain sources of supply—for example, by signing fixed-price contracts with suppliers—and increases that incentive for customers. To the extent that prices vary more directly with costs, there may be an increase in allocative efficiency at the expense of productive efficiency. There is a reduction in transparency because of the added complexity in the regulatory formula and the reduced predictability of prices.

U.K. practice has varied. Both BT and BAA have zero pass-through (except for three quarters of the unforeseen additional cost of airport security). The price controls in the other three industries make significant provision for pass-through: for BG the costs of buying gas; for the water authorities, the costs of meeting any unforeseen government commitment such as new EC directives (subject to a minimum threshold set at 10% of turnover); and for public electricity suppliers, the costs of purchasing electricity from the generating companies. In the latter case, a yardstick provision (relating a proportion of pass-through to the costs of the industry as a whole) is also envisaged.

Tariff basket versus revenue yield. Another feature of price control is the precise rule for determining allowed price changes. BT's rule is based on the concept of a "tariff basket," whereby price changes must be such that the average price of the services in the basket, as weighted by *observed* usage in the *previous* year, does not increase by more than $RPI - X$. The water industry has a similar rule. In contrast, price regulation for BAA and BG (and prospectively for the privatized electric companies) is based on a "revenue yield" approach, whereby price changes must be such that the *forecasted* average revenue-per-unit of output (e.g., per passenger or per therm) in the *next* year does not increase by more than $RPI - X$. The necessary forecasts of output are made by the regulated company itself, and the formula involves an additional correction factor to repay or recoup any deviation between prediction and outcome.

The relative incentive effects of each type of formula have been debated and are not unambiguous, although it has been suggested that the revenue yield approach is more open to strategic behavior by the regulated firm. (See Cheong (1989)). Revenue yield may be expected to reduce the risk to the regulated company in two ways: it smoothes, over time, the average revenue-per-unit and gives the company (via determination of the forecasts) greater control over the total level of revenue. As with cost pass-through, however, this simply transfers the risks to customers and may reduce the company's incentive to seek a less variable pattern of income. There is also less transparency as the regulatory formula becomes more complex and future price changes less predictable.

In sum, the record on transparency is somewhat mixed. BT's simple $RPI - X$ constraint is still in place, but three of the other utilities make heavy use of cost pass-through, and three have revenue yield constraints based on expectations declared by the regulated companies themselves. Such features reduce transparency and efficiency, though they may protect profits and proceeds or may allow a tougher X on prices. In the absence of transparency, protection for customers has to depend upon faith in the regulatory process rather than upon an explicitly guaranteed outcome. In this respect, cost pass-through and revenue yield are similar to rate-of-return regulation.

3. The promotion of competition

■ The promotion of competition is not traditionally associated with the regulation of utilities in the U.S. The regulatory commissions have a long record of resisting entry, and it has been persuasively argued that the real purpose of regulation was to protect incumbents from competition (Stigler, 1971 and Jarrell, 1978). Admittedly, competition issues have loomed increasingly large in telecommunications, especially since the "above 890"[4] decision in 1969. The FCC has been concerned lately with protecting entrants from various forms of anti-competitive pricing. Nonetheless (and in contrast to antitrust policy), there is nothing in U.S. utility regulation approaching a statutory duty to promote competition.[5]

The U.K. regulator's duty to promote competition reflects in part the fact that it is not possible to move from a nationalized monopoly to a competitive industry in a single step. The regulator needs the authority and duty to complete the process of transition (as does the Secretary of State), otherwise obstacles to competition might remain in place.

The emphasis placed on this duty differs greatly between industries, depending upon the scope for entry afforded by the underlying technical and market conditions. At one extreme, potential competition is very limited in water supply, sewage disposal, and airports.[6] The promotion of competition has a correspondingly small place in the Airports Act of 1986 and the Water Act of 1989. At the other extreme, the 1984 Telecommunications Act and the associated licenses are, to an important extent, addressed to the pace at which competition in telecoms is permitted to develop. The regulator has a potential role in the licensing of entrants, specifying the terms on which rivals have access to BT's network and other facilities, and constraining BT's pricing policy (which might encourage or deter entry). Analogous provisions are embodied in the Electricity Act of 1989 and licenses. To a lesser extent, this is true of the Gas Act of 1986 and license, where the role of the regulator in promoting competition in gas supply has subsequently been strengthened as a result of the MMC report on that industry.

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[4] In Allocation of Frequencies in the Bands Above 890 Mcs, 27 F.C.C. 359 (1959), the Federal Communications Commission authorized the licensing of private communications systems to give large users an alternative to obtaining service from AT&T. Although this decision had little immediate effect, it set the stage for the introduction of Specialized Common Carriers, such as MCI, which eventually led to the competitive supply of ordinary long-distance telephone service.

[5] The text by Phillips (1969) devotes just 2½ of its 774 pages to the then-novel concept of strengthening the forces of market competition.

[6] Competition *for* the market, via franchising, has been much discussed (see Vickers and Yarrow (1988); Spulber (1989)), but is beyond the scope of this article.

The duty to promote competition cannot be taken in isolation. The regulator needs to take into account a variety of other economic, social, and political considerations. Specifically, he has duties to secure the financing of licensed activities and protect the interests of consumers. In most situations, different policies will be indicated, depending upon the weight given to each duty. We now give two examples of how regulators have in practice resolved this issue. We then consider the appropriate mode of economic analysis and suggest a direction for future research in order to improve the effectiveness of regulation to promote competition.

□ **An illustration from telecommunications.** When Mercury wished to interconnect with BT, it was unable to agree on terms, and the regulator, in accordance with BT's license, was called upon to adjudicate.

One option, stemming primarily from the duty to protect the interests of customers and using traditional welfare economic concepts, was to attempt to calculate levels of interconnect charges which maximized allocative efficiency. This would have required a detailed calculation (for each possible level of interconnect charges) of Mercury's likely outputs in relevant markets, BT's consequent costs and losses in revenue, and the effect of these revenue losses on BT's prices and outputs. Mercury's market share would fall out as a residual from this exercise. However, the approach would beg the question of how to determine Mercury's output reaction function, and Mercury's implied strategy of entry and growth would not necessarily be consistent with promoting competition.

An alternative option was to begin with the duty to promote competition and therefore to examine the impact of the interconnect decision on Mercury's strategy. This would have meant looking at the situation from Mercury's perspective. The margins it could secure were central to its prospects for building up its voice (and other) telephony business. Favorable access to BT's local distribution system meant that Mercury's customers could get not only the benefits of lower prices for calls made over Mercury's long-distance system, but also discounts on virtually all calls delivered by BT. Furthermore, the prospects for future entrants could be expected to depend on the terms achieved for Mercury. Of course, the interconnect charges to be paid by Mercury and others were only part of the story about predicting entry. The effects on BT's costs, revenues, prices, and outputs also needed to be taken into account. Nevertheless, the thrust of this approach is quite different from the allocative efficiency approach, and it would be surprising if its policy implications were the same.

Oftel's *Annual Report for 1985* simply noted that the Director General "established the prices, based on BT's costs, which should be paid by MCL (Mercury) to BT for use of its network." No explanation of this cost basis was given, perhaps to avoid any statement that might evoke a test of the decision by the courts. It is widely felt that the phrase "based on BT's costs" has to be taken with a pinch of salt. There was almost certainly no attempt to run a model of allocative efficiency. The essence of the matter was that the regulator either had to provide sufficient inducement for Mercury to enter the market, or his decision would put at risk a central point of the government's strategy—that Mercury should become a serious competitor. The regulator's decision does seem to have established a key condition for future effective competition. When it came to the crunch, therefore, the regulator did not let considerations of allocative efficiency stand in the way of a judgement about the promotion of competition, although the precise basis for this judgement was not given.

□ **An illustration from gas.** The second example is found in the MMC's 1988 report on gas. There had been numerous complaints against BG's policy of discriminating in price, according to whether its customers had access to an alternative fuel (typically oil). These customers, industrial consumers of substantial quantities of gas, lay outside the $RPI - X$ price control basket, but were nevertheless within the regulator's general duty to enable competition. The privatization acts empower a regulator to refer any practice to the Monopolies and Mergers Commission. The regulated companies are also subject to general competition law, and it was in fact the Director General of Fair Trading who referred BG to the MMC.

It is well known that, from an allocative point of view, price discrimination may have certain desirable properties. It can lead to greater output and aggregate value of output than a uniform monopoly price. Perfect discrimination yields an output and aggregate value of output precisely equal to that of perfect competition. Nevertheless, the MMC opposed BG's policy of price discrimination, primarily because it would deter new entry.[7] The MMC acknowledged that the prohibition of price discrimination was likely to make some customers worse off, and would limit BG's ability to compete against the oil companies. However, it believed that these disadvantages would be outweighed by the improved prospects for new entry which would be necessary to create "gas-on-gas" competition, to which the MMC attached great importance.

This conclusion was consistent with the regulator's own view as given in evidence to the Commission. The MMC found BG's policy to be against the public interest and accepted the regulator's suggestion that BG should be required not to discriminate in price. It recommended specific provisions against discrimination to be incorporated in BG's license. The regulator subsequently negotiated a license modification of this kind. (Similar nondiscrimination provisions have been incorporated into the draft licenses of the electric companies.)

□ **Economic analysis of new entry.** The two examples presented above indicate that regulators have taken seriously their duty to promote competition, and that in so doing they have implicitly gone beyond traditional welfare economics. We now consider what the problem of promoting competition involves, and what kinds of economic analysis might be most helpful in that task.

Promoting competition involves facilitating the entry of new competitors, including the entry of existing competitors into new parts of the market. To do this effectively involves three main steps. The first is to assess the likely pattern of entry over the forseeable future. This will require a prediction of likely changes in technological and market conditions, since these will often provide the necessary opportunities for entry. The second step is to identify decisions that the regulator himself can make in order to change the regulatory framework, and to assess the likely impact of these changes on the future pattern of entry. Examples of these regulatory decisions (in the British system) are the licensing of new entrants, identification and prohibition of anti-competitive practices, determination of interconnect or common carrier (use of system) charges, collection and publication of relevant information, and so on. The third step is to choose which regulatory changes to make. Other things being equal, the preferred changes are those likely to have the greatest positive impact on entry. This is not always an obvious calculation, however, particularly since the whole time path of entry must be considered. The telecommunications duopoly policy, for example, reflects in part the view that where an entrant has to make a large cost commitment, it is more likely to enter, the less swiftly is a subsequent entrant able to attack the same market (Carsberg, 1987).

In order to promote competition, the regulator's essential task is to assess the relation between his actions (which will include regulatory changes as well as determining disputes and constraining prices) and the probablity that entry will actually occur. He will need to consider the scale and time path of entry and its impact on all the parties involved as well

[7] "By relating prices to those of the alternatives available to each customer, it places BG in a position selectively to undercut potential competing gas suppliers; this may be expected to act as a deterrent to new entrants and to inhibit the development of competition in this market." (MMC (1988), paragraph 8.38 (b).)

as on other potential entrants. It will prove impracticable to analyze all the possible avenues and problems of entry simultaneously, however, if only because the regulator's time and resources are necessarily limited. The regulator therefore has to be selective, i.e., to take a view about where entry might be most likely, if encouraged, and hence most effective in producing net benefits to consumers and producers, as they will be refined by the impact of entry.

What kind of economic model is most helpful in doing this? It is natural to begin with the same comparative static welfare economic approach that is conventionally used to analyze the problem of price control. This model takes as given (1) the relevant cost and demand functions, and (2) the extent of competition in the market, which essentially depends on the conditions of entry. These assumptions are used to trace the implications for (equilibrium) prices, outputs, profits, number and size of firms, and so on. It is then asked, What kinds of constraints on the regulated firm will maximize aggregate net surplus subject to securing adequate protection for various classes of consumers? Rate-of-return regulation is set firmly in this world. There is an extensive literature aimed at determining optimal pricing and investment rules that maximize allocative efficiency, taking costs and demands as given.

RPI − *X* requires the relaxation of the first assumption. It does *not* assume costs and demands are given or known: indeed, the problem is to provide adequate incentives for the company to discover them. The aim is to stimulate alertness to lower cost techniques and hitherto unmet demands. The emphasis is on productive rather than allocative efficiency (and even the *RPI* −*X* price cap reflects distributional rather than allocative considerations). This is an Austrian world rather than a neoclassical one. (Austrian is here defined broadly to include both Leibenstein's familiar *X*-efficiency on the cost side and the corresponding *Y*-efficiency on the demand side proposed by Beesley (1973).)

The problem of promoting competition requires the relaxation of the second assumption. Here, the extent of competition and the conditions of entry are not given: the essential regulatory task is to ascertain what they are and how they might be changed. The object is to choose the regulatory policy which will maximize new entry, subject to adequate protection of the interests of producers and present consumers. Nor are costs and demands assumed given or known. Indeed, one of the means of promoting competition is precisely to *shift* potential entrants' assumptions about the costs and possibilities of serving new markets, and one of the expected benefits of entry is a shift in the incumbents' own assumptions about these parameters.

Substantial recent literature on potential competition and contestable markets analyze the relationship between conditions for entry and price. At least one textbook on regulation (Spulber, 1989) is more concerned with entry and competition than with static welfare analysis of pricing for a protected monopoly. There have also been important developments in the economic analysis of strategic behavior (Dixit, 1982).

In practice, however, these models are of limited use for the task of promoting competition. Although they analyze the effects of any given entry conditions, they do not help to identify what the entry conditions *actually are* in any particular situation, nor what the entry conditions *would be* as a result of any particular regulatory change. Thus, they are of limited assistance to the regulator in assessing how much entry will take place, and where, when, and by whom, as a result of different regulatory policies.

Briefly, an alternative approach would run as follows. In order to identify the entry conditions obtaining at any time, and to predict the consequences of a change in policy, the regulator needs to start from the question, Where and when will entry be *profitable?* This in turn requires looking at the situation from the point of view of the potential entrant. Given its assets, knowledge, resources, its ability to buy at current input prices, and the pricing and product policy of the incumbent(s), what parts of the existing market can it profitably develop? What (if any) better contracts with respect to cost, including superior productivity, can it establish? Where have incumbents missed possibilities for adding value or been unable for various reasons to supply? How will incumbents react to its entry? Can it survive their response? In short, what advantages does it have over the incumbents, and how long will these advantages last? The answers to these kinds of questions determine the central calculation for an entrant: the equity that the entrant needs to ante up in order to be a player in the game (that is, its risk capital reflecting its potential sunk cost if unsuccessful), and its potential net revenue stream if successful (the reward for taking the risk).

Admittedly, the models referred to earlier assume profit maximization, but they do not ask where the profit is coming from. They deal with profit in a purely formal way which does not highlight the need for information about entry and gives little help to the regulator in identifying the relevant factors in practice. Future research might usefully reflect the Austrian insistance on profit as the engine of capitalism and, in particular, on the exploitation of hitherto unforeseen profit opportunities as central to the continuing market process (Schumpeter, 1950; Kirzner, 1973, 1985). Examination of actual rather than hypothetical situations is also necessary, as Coase (1988) has long argued. Applications of the proposed approach (e.g., Beesley (1986) on airlines and Beesley and Laidlaw (1989) on telecommunications) suggest that there is more scope for promoting competition than has hitherto been recognized.

4. Regulatory effectiveness

■ We argued in Section 2 that the $RPI - X$ system offers more scope for bargaining, especially on productivity, than rate-of-return regulation. The importance of this depends upon the potential for productivity improvements and on the information available to the regulator to exploit this situation effectively. We also argued that $RPI - X$ offers the company more flexibility in pricing. Whether this is an advantage or disadvantage depends on the need for price changes, on the information available to the regulator, and on the existence of alternative instruments of policy. In Section 3 we noted the U.K. regulator's explicit duty to promote competition, which in practice has been taken very seriously. Regulatory effectiveness depends upon the scope for new entry and, again, on the information available to the regulator.

In order to carry out his twin tasks of controlling prices and promoting competition, the regulator thus needs to acquire adequate information concerning the scope for cost reductions and the extent and effects of new entry. He will also need to transmit information to incumbents and potential entrants, in order to improve both efficiency and the prospects for entry. The generation and dissemination of information are therefore at the heart of regulatory effectiveness.[8]

Various devices intended to give companies the incentive to provide the regulator with relevant information have been suggested in the recent economic literature.[9] Typically these devices are set within the context of a given technology and product line: innovation and entry are not encompassed. Once the latter phenomena are admitted, it becomes apparent that the information which the regulator acquired is ephemeral: over time, it gradually becomes obsolete and needs to be replenished. Thus, if the regulator is to succeed in either of his two tasks—controlling prices or promoting competition—he needs to acquire infor-

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[8] Like the market participants, the regulator himself needs to be alert to hitherto undiscovered opportunities for profit, deriving from both the cost and demand sides. Kirzner (1978) has argued that "nothing within the regulatory process seems able to simulate, even remotely well, the discovery process that is so integral to the unregulated market." Our argument is not that the regulatory process is more effective than the competitive market process. (As indicated, the regulator has some advantages and some disadvantages compared to market participants.) Rather, our argument is that an effective regulator needs to be alert in order to promote greater alertness in markets that are not (yet) competitive.

[9] See, for example, the surveys and references in Vickers and Yarrow (1988) and Spulber (1989).

mation at a rate faster than that at which it decays. The feasibility of doing this depends on two main parameters.

First, there is the rate at which the underlying technological and market conditions change. The slower the change, the more likely the regulator will gradually come to acquire more relevant information and will be in a position to set realistic productivity targets (and, for that matter, performance standards) and determine allocatively efficient price structures for the regulated utility. He will also be able to assess the effects of new entry more accurately. Where the underlying rate of change is slow, new entry is less attractive. In these circumstances, there is likely to be greater payoff to controlling prices than to promoting competition. Conversely, the faster the underlying rate of change in the industry, the more likely it is that the regulator's knowledge will decay faster than he can replenish it, hence the less likely it is that he will be able to control prices efficiently.[10] However, rapid change provides the very circumstances in which new entry is feasible. Hence, in these circumstances, the regulator's priority should be to promote competition rather than control price. In the longer term, as the industry becomes more competitive, this will tend to reduce the need for price regulation.

The second main possibility of the regulator acquiring information faster than it decays is where there are multiple sources of information. Where there are many companies in an industry, even though they necessarily differ one from another, they may be sufficiently similar that the regulator can use the performance of one as an indication of what another could achieve. This yields a basis for setting efficiency targets in an $RPI - X$ price control scheme. In these circumstances, the regulator's priority is to ensure that the laggards improve to match the (observed) performance of the leaders, while providing sufficient incentive for the leaders to stay ahead and blaze the way for the next round of target setting. The threat of takeover (if either the leaders or the laggards lapse into managerial slack) is an important aid in this endeavor. Conversely, where there is only one company in an industry, the regulator is more dependent upon that company for information, and his effectiveness in bargaining for productivity improvements is thereby reduced.

The prospects for generating information for regulatory purposes should therefore be an important argument in a government's decisions about the structure of the industry and the nature of the regulatory regime. Where the underlying rate of change is slow, there will be information advantages in creating and maintaining many similar firms for purposes of comparison.[11] Of course, it is economically efficient to do this only where the benefits of greater information are expected to outweigh any economies of scale or scope. This is more likely to be the case where a regulated industry is mainly an aggregate of several local monopolies (as with airports and local distribution networks for gas and electricity) than where the natural monopoly element is itself on a national scale (as with bulk transmission grids for gas or electricity).

□ **An illustration from the United Kingdom.** These ideas may be represented in a 2×2 matrix. In Tables 1 and 2, the columns represent the underlying rate of change in technology (and market conditions), classified as "Low" or "High," while the rows represent the number of regulated companies in the industry, classified as "One" or "Many." Each regulated industry, or part thereof, can be located in one of the resulting four cells.

Table 1 shows the matrix as it appears today for the five regulated utilities in the U.K. The foregoing analysis indicates a policy of promoting competition in telecoms, gas supply, and electricity generation and supply. Water and electricity distribution provide the most

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[10] Beesley and Glaister (1983) argued that this is the case in the taxicab industry. Wiseman (1957) has long argued that the very notion of an optimal price is untenable once uncertainty and change are admitted.

[11] When dealing with mergers, the Water Act of 1989 embodies instructions to the MMC to this effect.

TABLE 1 **Present Position**

	Rate of Change of Technology	
	Low	High
Number of regulated firms		
Many	Water Electricity Distribution	
One	Electricity Transmission Gas Transmission and Distribution Airports	Telecoms Electricity Generation Electricity Supply Gas Supply

promising conditions for price control. The difficulty of the single regulated utility presents itself in airports, electricity transmission, and gas transmission and distribution.

The structure of those industries characterized by a low rate of technological change could only be altered by government legislation (and clearly many other factors would need to be considered). Where there is a high underlying rate of change, however, the promotion of competition—at its simplest, by licensing new entry—would shift those industries in the one-firm cell into the many-firm cell. With the development of competition, specific industry regulation would become less necessary; whatever needed to be done to help keep competition active might well be performed by the anti-monopoly legislation common to all industries. In other words, deregulation might be indicated.

Table 2 shows the situation that could result in the United Kingdom if the policies discussed were put into effect. In telecoms, gas supply, and electricity generation and supply, the regulator's role of promoting competition would be paramount, perhaps via general competition policy rather than by specific regulation. In water, airports, and gas and electricity distribution, an emphasis on price control would be indicated, with prospects of success. The problematic areas would be national transmission grids for gas and electricity. Paradoxically, because transmission is so crucial to supply, regulatory attention in these natural monopolies would need to focus also on the promotion of competition in upstream and downstream markets via the terms to be set for the use of transmission facilities. So for electricity and gas transmission (and distribution too) the dual role of the regulator might be expected to continue in the foreseeable future.

□ ***RPI* − *X* versus rate of return revisited.** Future research might usefully assess U.S. and U.K. regulatory systems in terms of the ideas suggested in this section, comparing their abilities to generate and use relevant information, depending upon rate of technological

TABLE 2 **Potential Position**

	Rate of Change of Technology	
	Low	High
Number of regulated firms		
Many	Water Electricity Distribution Gas Distribution Airports	Telecoms Electricity Generation Electricity Supply Gas Supply
One	Electricity Transmission Gas Transmission	

change and number of regulated firms. We may illustrate this by reexamining the initial question of the relative merits of $RPI - X$ and rate-of-return regulation with respect to incentives and efficiency. We argued that $RPI - X$ is indeed different because (*inter alia*) it incorporates a fixed risk period within which gains above the productivity bargain can be kept by the regulated firm(s). These productivity gains are potentially larger at the time of privatization than subsequently. They are also potentially larger the more rapidly technological conditions are changing, and where there are many different firms, with leaders blazing the way for laggards to follow.

Relating these considerations to the five regulated utilities, it follows that the case for $RPI - X$ price control rather than rate-of-return regulation is strongest in telecoms, gas supply, and electricity supply, where technology is indeed changing. If the aim is to "hold the fort" until competition arrives, as Beesley and Littlechild (1983) put it, $RPI - X$ will do this with greater potential productivity gains. At the other extreme, where there is less prospect of a shift in technology and only one firm in the industry, as with the electricity and gas transmission grids, there is less scope for bargaining about the potential for improvements in efficiency and no built-in mechanism to give the regulator scope for bargaining via directly relevant comparisons. Here, the grounds for preferring $RPI - X$ are least strong.

In the remaining industries, notably water, gas, and electricity distribution, there is a strong reason for preferring $RPI - X$ initially, given the potential productivity gains on privatization and the regulator's potential for generating superior information to that available to the companies taken separately. Admittedly, if there is indeed a low underlying rate of change in technology, both the scope for improvement and the discrepancies between companies may be expected to reduce over time, and in practice an $RPI - X$ regime may gradually become indistinguishable from that of rate-of-return regulation. However, a permanently low underlying rate of change cannot be taken for granted. For the present, $RPI - X$ seems to offer advantages.

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Appendix D8-4

A MODEL OF SLIDING-SCALE REGULATION

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A Model of Sliding-Scale Regulation[1]

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Abstract
Price caps, while widely touted, are less commonly implemented. Most incentive schemes involve profit sharing and are, thus, variants of sliding-scale regulation. I show that, relative to price caps, some degree of profit sharing always increases expected welfare. Numerical simulations show that welfare may be enhanced by large amounts of profit sharing and by granting the firm a greater share of gains than of losses. Simulations also suggest profit sharing is most beneficial when the firm's initial cost is high and cost-reducing innovations are difficult to achieve but offer the potential for substantial savings.

1. Introduction

For years economists have complained about the woefully poor incentives created by traditional rate-of-return regulation. Over the last decade, however, the institutional innovation of "price-cap regulation" has emerged, offering greatly enhanced incentives for efficient production and pricing.[2] Nevertheless, many if not most of the "incentive regulation" plans implemented in recent years do not simply cap prices. Typically they also include limits—-sometimes called "zones of reasonableness" or "deadbands"—-on how much the firm can gain or lose before triggering profit-sharing with customers.[3] Such regulatory

1 This paper has benefitted from the comments of Mark Bagnoli, Jim Burgess, Michael Crew, Steve Hackett, Paul Kleindorfer, Michael Riordan, Ted Stefos, Ingo Vogelsang, Dennis Weisman, two anonymous referees, and workshop participants at the First Annual Northeastern Health Economics Conference, the Fourth Annual Health Economics Conference, GTE, Indiana University, the Rutgers Advanced Workshop in Regulation and Public Utility Economics, and the 20th Telecommunications Policy Research Conference. Financial support from the Management Science Group of the Department of Veterans Affairs and from Indiana University is gratefully acknowledged.

2 Prominent examples in the United States include "price cap" regulation of AT&T by the Federal Communications Commission (FCC) and fixed reimbursement payments for given diagnostic-related groups under Medicare. A review of the extensive British experience with price caps is given by Armstrong, Cowan, and Vickers (1994).

3 The FCC's original price-cap plan for the interstate access charges levied by the local exchange carriers (LECs), enacted in 1991, offered LECs a choice between two different earnings-sharing plans. After the first three years of this plan, the FCC revised the schemes and added a third plan that involves no sharing. For more details, see Sappington and Weisman (forthcoming). Over half the states in the United States have adopted earnings sharing schemes, as discussed in detail by Greenstein, McMaster, and Spiller

schemes are known as "sliding scale" (SS) plans. The recent enthusiasm for SS regulation has been something of a mystery to economists, since it does not appear to reflect a new theoretical case for its incentive effects. In fact, Braeutigam and Panzar (1993, 197) see SS regulation as "a classic case in which practice is far out ahead of theory" and note that (p. 195) "[i]n view of the widespread and continuing implementation of [sliding-scale] plans, especially at the state level, a modern analysis of their effects on firm behavior and economic efficiency is long overdue." This paper attempts such an analysis.

The model presented here provides a strong efficiency rationale for SS regulation. The analysis revolves around the interplay between the firm's incentives for cost-reducing innovation, the transaction costs of rate review, and the deadweight losses caused when prices and costs are not properly aligned. A comparative institutional approach is taken, using a modeling framework that encompasses rate-of-return regulation, price caps, and sliding scale regulation.[4] SS regulation is seen as a flexible combination of the other two alternatives, with profit-sharing used to balance the competing goals of providing incentives for cost reduction and of allowing price to track cost. The "deadband" reflects the high transaction costs associated with rate reviews and allows these costs to be avoided when the benefits of price adjustment are small. The results indicate that SS regulation, if properly designed, always offers greater welfare than pure price caps, which do not allow for price to adjust to cost ex post. The optimal sharing rule often involves substantial refunds of profits to consumers and may allow the firm to retain a greater share of gains than losses. The additional welfare benefits of profit-sharing over pure price caps are greatest when the firm has high costs and when cost-reducing innovations are difficult to achieve but offer the potential for substantial savings.

The remainder of the paper is organized as follows. Section 2 briefly surveys the literature. Section 3 presents the basic model. Section 4 analyzes the benchmark cases of cost-plus, rate-of-return, and price-cap regulation. Section 5 characterizes when sliding-scale regulation is welfare-enhancing relative to rate-of-return regulation and to price caps. Section 6 presents simulation results that extend the analytical results of section 5. Conclusions are offered in section 7.

2. Literature Review

The literature on profit-sharing is quite small.[5] Greenstein, McMaster, and Spiller (1995)

(1995). The prospective payment system (PPS) used by the Veterans' Administration is designed so that a hospital cannot gain or lose more than 3% of its previous period's budget. See Stefos, Lavallee, and Holden (1992, 5-6), for details. The California Public Utilities Commission (CPUC) has regulated transportation rates for some natural gas customers using what it calls a Negotiated Revenue Stability Account (NRSA) that "banded the effect that current incentive mechanisms could have on utilities' returns to a 300 basis point difference from the authorized level.'' See California Public Utilities Commission (1990, 19-20). Indiana has recently enacted a scheme for PSI Energy that gives the company all earnings below 10.6%, consumers all earnings beyond 12.3%, and uses a graduated sharing schedule between these two levels. See Indiana Utility Regulatory Commission (1990, 13).

4 Using a related framework, Cabral and Riordan (1989) and Clemenz (1991) study investment in cost reduction under rate-of-return regulation and under price caps. Neither paper considers cost- or profit-sharing, however, and their characterizations of rate-of-return and price-cap regulation differ significantly from those used here, as discussed in footnote 10 below.

5 There is, of course, an extensive literature on optimal regulation under conditions of adverse selection,

study empirically how state regulators' profit-sharing plans affect investment by local telephone exchange companies. They find that price-cap plans offer stronger incentives for investment than do profit-sharing plans. Similarly, Majumdar (1995) measures the technical efficiency of local exchange companies, finding that price caps induce greater efficiency gains than do profit-sharing plans. Since these studies ignore questions of allocative efficiency, however, they cannot offer a welfare assessment of the respective plans.

There is also a theoretical literature that addresses the welfare effects of profit-sharing schemes. Sappington and Sibley (1992) find that small amounts of profit-sharing may improve welfare relative to some forms of price-cap regulation when investment is observable; this result becomes ambiguous, however, when investment is unobservable. Weisman (1993), in a multiproduct setting, shows that various distortions which result when common costs are allocated across products can be avoided by the use of price caps, but not by the use of profit-sharing regulation. Gasmi, Ivaldi, and Laffont (1994) use numerical simulations to analyze profit-sharing for a monopolistic firm in an adverse selection setting with unobservable investment. They find that a deadband and profit-sharing are substitutes: either a deadband is used and all earnings outside it are rebated to consumers, or there is no deadband and profit sharing is employed. This dichotomy between regulatory plans bears little resemblance to the schemes used in practice, however, where deadbands and profit sharing appear to be complements rather than substitutes. Lyon (1995) shows that the combination of a deadband plus profit-sharing can induce the efficient choice between a conventional technology and an innovative technology whose costs are lower in expected value but higher in variance. Lyon and Huang (forthcoming) study incentives for the adoption of new technology when a firm under profit-sharing regulation competes with an unregulated firm. They find that, depending on the relative cost of innovation versus imitation, the industrywide rate of innovation may either speed up or slow down when the regulated firm is allowed to keep a larger share of profits.

This paper differs from the theoretical papers discussed above in several ways. Unlike Sappington and Sibley (1992), I focus on unobservable cost-reducing investment that has non- deterministic effects and on linear pricing schemes. I also use simulation analysis to investigate degrees of profit-sharing that depart significantly from price caps. Unlike Weisman (1993), I study a single-product firm in order to focus on the case where costs are uncertain and profits are returned to customers via price reductions rather than lump-sum transfers. Unlike Gasmi, Ivaldi, and Laffont (1994), the model presented here is fundamentally one of moral hazard, or hidden action, rather than hidden information.[6] Both types of model capture important aspects of reality, and the choice between them reflects beliefs about the relative importance of effort provision versus information revelation, as well as their

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much of which emphasizes the sharing of costs between the regulator and the firm. For a thorough treatment, see Laffont and Tirole (1993). Schmalensee (1989) analyzes a model in which price is a linear function of cost and provides a variety of interesting simulation results.

6 In the latter family of models, the principal typically distorts pricing behavior in subtle ways in order to minimize the informational rents earned by the agent possessing private information. Moral hazard models, on the other hand, usually trade off incentives for greater effort—generated by giving the agent a greater claim to residual surplus—against the cost such claimancy imposes on the risk-averse agent when outcomes are stochastic. My model differs from the typical moral hazard setup in that the firm is risk-neutral and allocative efficiency substitutes for risk-aversion as the brake on the use of high-powered incentives.

ability to explain and predict behavior. One appealing aspect of my simple model is that it provides a clear explanation for the complementary use of deadbands and profit sharing, which Gasmi et al. (1994) do not. This paper also differs from Gasmi et al. (1994) in that it returns excess earnings to consumers via price reductions (as is typically done in practice) rather than lump-sum transfers, and it does not impose ex post limited liability, so both the sharing of gains and of losses is allowed. The basic structure in the present paper is similar to that in Lyon (1995), but the earlier paper focuses on a positive analysis of the regulated firm's choice between discrete technological alternatives, while the current paper takes a broader view of social welfare that trades off productive and allocative efficiency. Finally, this paper differs from Lyon and Huang (forthcoming) in its focus on optimal profit-sharing rules for a regulated monopolist.

3. The Basic Model

In this section, I present a stylized model of firm behavior under regulation. The firm can invest in innovative efforts to reduce costs, the success of which cannot be predicted perfectly. Examples of such investments might include research and development, changes in the way the firm is organized, or the adoption of new production techniques. Regulators are assumed to be unable to observe the firm's effort directly.

The regulatory process as modeled here is motivated by an underlying process of interest group politics. As is well known, under Supreme Court decisions such as *Munn v. Illinois*, states can regulate profits in industries "affected with a public interest;" similarly, firms are entitled, under *Federal Power Commission v. Hope Natural Gas*, to seek rate increases when profits are low. As emphasized by Joskow (1974) and Peltzman (1976), however, interest groups wishing to affect the political process must incur the transaction costs of acquiring information and organizing for action; thus, interest group pressure for rate review tends to emerge only when economic conditions diverge significantly from those at the last review.

More formally, consider a risk-neutral single-product firm with constant marginal and average production cost c. Its initial cost is c_0, but this can be reduced, albeit with some uncertainty, depending on the amount e the firm expends on cost-reduction activities. There is thus a probability density function $f(c \mid e)$ with cumulative $F(c \mid e)$ that relates cost to effort. I assume $F(0,e) = 0$, $F(c_0 \mid e) = 1$, and that cost-reducing effort is subject to decreasing returns, i.e., $F_e(c \mid e) \geq 0 \geq F_{ee}(c \mid e)$. Both the regulator and the firm have access to historical data on prices and sales, but while the firm chooses e, the regulator cannot observe it. Let $\psi(e)$ represent the firm's disutility of effort, with $\psi'(e) > 0$ and $\psi''(e) > 0$.

I follow Banks (1992) in assuming that the firm's costs and earnings are observable but can only be verified for rate-making purposes by holding a formal rate review, which entails social costs of Δ.[7] At any point in time, the price from the most recent rate review, p_0, remains in effect unless a new rate review is held.

The basic price adjustment mechanism in this model is quite simple. An initial price p_0 is set less than or equal to the most recent observation of average (and marginal) cost, c_0. Given p_0, the firm's earnings *gross* of cost-reduction expenses are $R(c) \equiv [p_0 - c]q(p_0)$, and

7 The costs of the firm, consumer groups, and regulatory staff are all included in Δ.

net of cost-reduction expenses are $R(c) - \psi(e)$. The price remains unchanged as long as earnings remain within the "deadband," i.e., between a lower bound L and an upper bound U. These upper and lower bounds are shaped by the cost to interest groups (the firm and consumers, respectively,) of mobilizing to participate in the regulatory process. If $R(c) \notin [L,U]$, then any gross earnings outside the deadband are shared between ratepayers and shareholders, with α^L the firm's share of gross earnings below the deadband and α^U the firm's share of gross earnings above the deadband. Thus, allowed profits are

$$\pi(c \mid e) = \begin{cases} L + \alpha^L[R(c) - L] - \psi(e) & \text{if } R(c) < L \\ R(c) - \psi(e) & \text{if } R(c) \notin [L,U] \\ U + \alpha^U[R(c) - U] - \psi(e) & \text{if } R(c) > U. \end{cases} \tag{1}$$

I assume the regulator is unable to make use of lump-sum transfers and can only adjust profits by changing the output price p.[8] Thus, when $R(c) > U$, the regulator sets a new price p so that the new revenue requirement is $\mathscr{R}(c) = U + \alpha^U[R(c) - U] = \alpha^U R(c) + (1 - \alpha^U)U$. The price, p^U, that achieves this objective is found by setting $(p^U - c)q(p^U) = \alpha^U(p_0 - c)q(p_0) + (1 - \alpha^U)U$. A similar procedure applies for $R(c) < L$. It is not possible in general to obtain a closed-form solution to this pricing problem, although a solution can be found for specific demand functions.

The above structure captures as special cases several familiar regulatory schemes:

- Cost-plus (CP) regulation: $L = U = 0$, $\alpha^U = \alpha^L = 0$. Price, ex post, is always set equal to observed marginal cost.
- "Pure" price-cap (PC) regulation: $\alpha^U = \alpha^L = 1$. Price is set at an initial level $p_0 \leq c_0$ and remains unchanged regardless of observed marginal cost.
- Rate-of-return regulation (RORR): $0 = L < U$, $\alpha^U = \alpha^L = 0$.[9] An initial price $p_0 = c_0$ is set and remains in place unless earnings are too high or too low. If earnings are too high, the firm reduces prices to avoid consumer outrage; if earnings are too low, the firm petitions for rate review and has price reset so as to just cover costs.[10]

In addition, the pricing rule described above allows for the more flexible structures being implemented in the industries mentioned above. Throughout the paper, I assume no "drastic" innovations are possible, i.e., even if cost is zero, the monopoly price $p^M(0)$ is at least p_0.[11]

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8 Schmalensee (1989) discusses this point at length.

9 See Braeutigam and Quirk (1984) for further discussion of this model of rate-of-return regulation.

10 There is some disagreement in the literature as to how rate-of-return regulation and price-cap regulation should be characterized. Schmalensee (1989) uses the static characterizations of cost-plus regulation and price-cap regulation given above; he does not explicitly model rate-of-return regulation. Cabral and Riordan (1989) and Clemenz (1991) model rate-of-return regulation as holding rate reviews at fixed intervals and price caps as allowing the firm to petition for a rate increase if and when it so chooses. Pint (1992), on the other hand, portrays RORR as giving the firm the right to initiate rate review, while under PC regulation reviews are held at fixed intervals. The empirical work of Joskow (1974) and Fitzpatrick (1987) supports the notion that traditional rate-of-return regulation gives the firm considerable power to manipulate the timing of rate reviews and, thus, comports with the modeling of Pint and of the present paper.

Define $c^U = p_0 - U/q(p_0)$ and $c^L = p_0 - L/q(p_0)$ as the cost levels at which the firm's earnings hit the upper and lower bounds on profits respectively. Then the relationship between price and cost for the three benchmark cases is as shown in figure 1.

The firm's expected profits can be written as

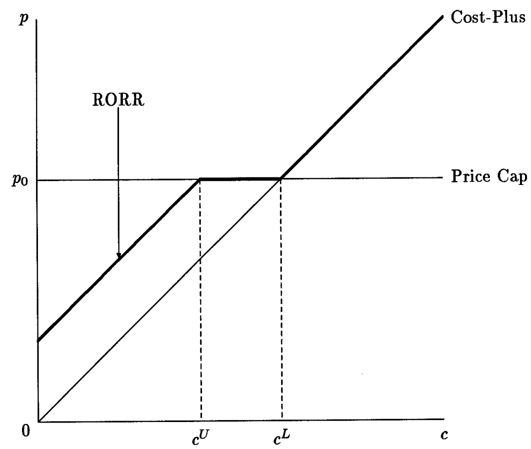

Figure 1. Pricing for Three Benchmark Cases

$$\bar{\pi}(e) = \int_0^{c^U} [(1-\alpha^U)U + \alpha^U(p_0 - c)q(p_0)]dF(c \mid e) + \int_{c^U}^{c^L} (p_0 - c)q(p_0)dF(c \mid e)$$
$$+ \int_{c^L}^{c_0} [(1-\alpha^L)L + \alpha^L(p_0 - c)q(p_0)]dF(c \mid e) - \psi(e). \tag{2}$$

Totally differentiating the firm's first-order condition with respect to effort, it is easy to show that $de/dL \le 0$, $de/dU \ge 0$, $de/d\alpha^L \ge 0$, and $de/d\alpha^U \ge 0$. The intuition for the signs on these terms is straightforward: the firm increases its cost-reducing effort when it appropriates a greater share of the benefits of effort. This greater appropriation occurs if the upper (lower) bound on earnings is raised (lowered) or if the firm receives a larger share of any earnings beyond U or L.

Since price is a function of cost, expected consumer surplus is $\bar{S} = \int_0^{c_0} S(p(c))dF(c \mid e)$ or, more explicitly,

$$\bar{S} = \int_0^{c^U} S(p^U)dF(c \mid e) + S(p_0)[F(c^L,e) - F(c^U,e)] + \int_{c^L}^{c_0} S(p^L)dF(c \mid e). \tag{3}$$

11 As the term is used in the literature, a "drastic" innovation is one which so lowers the cost of production that the monopoly price, based on the new cost, is below the original cost. If a firm in a competitive industry developed a drastic innovation, it would thus drive all its rivals out of business.

Total surplus (which I will refer to as "welfare") is $\overline{W} = \overline{S} + \overline{\pi}$ and will be the focus of much of the analysis to follow. Many normative models of regulation give profits a strictly smaller weight in regulatory objectives than consumer surplus. In a moral hazard model such as the one presented here, however, the weight placed on profits is relatively unimportant, since welfare maximization drives the firm to its reservation level, here assumed to be zero expected profits. Thus, only Proposition 4 of the paper would be affected if profits were weighted less than consumer surplus; these changes are discussed explicitly after the proposition is presented.

Differentiating expected consumer surplus with respect to α^U yields

$$\frac{d\overline{S}}{d\alpha^U} = \frac{\partial\overline{S}}{\partial\alpha^U} + \frac{\partial\overline{S}}{\partial e}\frac{de}{d\alpha^U}. \tag{4}$$

The first term (the "allocative effect") is always negative, since it requires price increases to consumers. The second additive term (the "incentive effect") is positive. As mentioned above, $de/d\alpha^U \geq 0$. Integrating (3) by parts and partially differentiating with respect to e yields

$$\frac{\partial\overline{S}}{\partial e} = \int_0^{c^U} q(p^U)\frac{dp^U}{dc}F_e(c \mid e)dc + \int_{c^L}^{c_0} q(p^L)\frac{dp^L}{dc}F_e(c \mid e)dc.$$

It can be shown that $dp^U/dc > 0$ and that if $L \leq 0$ then $dp^L/dc > 0$. Thus, if $L \leq 0$, then $\partial\overline{S}/\partial e > 0$, and the incentive effect of α^U on consumer surplus is positive. Similar expressions can be derived for α^L.

4. Benchmark Cases

I next examine the performance of the three benchmark regulatory systems outlined above.

4.1. Cost-Plus Regulation

Pure cost-plus (CP) regulation has $\alpha^L = \alpha^U = 0$ and $L = U = 0$, so that $p = c$ ex post. Because the firm's cost-reducing effort is unobservable, these costs are never recovered in rates and $\overline{\pi}(e) = -\psi(e)$. The firm has no incentive to reduce its costs and $e^* = 0$. As a result, price does not fall, expected profits are zero, and consumer surplus is governed entirely by the initial regulated price, e.g., $\overline{S}(e^*) = S(p_0)$. This form of regulation has received much public condemnation, but it is essentially a caricature. Authors such as Joskow and Schmalensee (1986) have discussed at length why traditional rate-of-regulation differs from a simple cost-plus format.

4.2. Rate-of-Return Regulation

Traditional rate-of-return regulation (RORR) is characterized by $p_0 = c_0$, $0 = L < U$, and $\alpha^L = \alpha^U = 0$. Then (2) becomes

$$\bar{\pi}(e) = \int_0^{c^U} U dF(c \mid e)dc + \int_{c^U}^{c_0} (p_0 - c)q(p_0)dF(c \mid e) - \psi(e). \tag{6}$$

Integrating by parts and differentiating with respect to effort, the firm's first-order condition becomes

$$\frac{d\bar{\pi}}{de} = q(p_0)\int_{c^U}^{c_0} F_e(c \mid e)dc - \psi'(e) = 0. \tag{7}$$

The presence of the "deadband" means that RORR induces a positive level of effort and, thereby, generates lower expected costs than cost-plus regulation. Furthermore, both the firm and consumers are better off than under CP regulation. The deadband allows the firm to keep some of the benefits of cost reduction, while consumers benefit because prices will be reduced for sufficiently large cost reductions.[12] These benefits are even greater when the transaction costs of rate review are recognized: the deadband economizes on the transaction costs of rate review when costs have changed little since the last rate review.

4.3. Price Caps

Pure price-cap (PC) regulation has $\alpha^L = \alpha^U = 1$, so $p = p_0$ ex post regardless of cost. (Because I assume $p^M(0) > p_0$, downward price flexibility makes no difference.) Thus, equation (2) reduces to $\bar{\pi}(e) = \int_0^{c_0} (p_0 - c)q(p_0)dF(c \mid e) - \psi(e)$, and, after integrating by parts, the firm's first-order condition is

$$\frac{d\bar{\pi}}{de} = q(p_0)\int_0^{c_0} F_e(c \mid e)dc - \psi'(e) = 0. \tag{8}$$

Obviously, $\bar{S}(e^*) = S(p_0)$. Thus, under pure price caps, consumers do exactly as well as they do under cost-plus regulation *if* the same initial price p_0 is used in both regimes. The firm, however, makes greater profits under price caps. The regulator can thus set the initial price cap lower than c_0 and capture for consumers some of the benefits of cost reduction. This is demonstrated in Lemmas 1 and 2 below.

Lemma 1. Under pure price cap regulation, (a) there exists a price $\underline{p}$ below which expected profit is negative. (b) For $p_0 > \underline{p}$, $de/dp < 0$.

Proof: See Appendix. Q.E.D.

Lemma 1 shows that lowering the initial price induces greater effort as long as the price is above $\underline{p}$.[13] Lemma 2 characterizes the social-welfare maximizing price under pure

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12 Note that the deadband plays a role similar, but not identical, to that of regulatory lag in dynamic models of regulation. The time period between rate reviews is driven by two components. First, because of the transaction costs of triggering a rate review, such a review will not be triggered until economic conditions depart significantly from those at the last review. Second, once review is triggered, there is a "processing lag" that reflects the time delays inherent in legal adjudication. The present paper reflects only the first of these aspects of regulatory lag.

price-cap regulation.

Lemma 2. Under pure price-cap regulation, if expected profits are kept non-negative, welfare is maximized at $p_0 = \underline{p}$.

Proof: Let $\overline{W}^*(p_0)$ and $\overline{\pi}^*(p_0)$ be expected welfare and expected profits respectively at the firm's optimal level of effort. It is straightforward to show that

$$\frac{d\overline{W}^*(p_0)}{dp_0} = q'(p_0)\frac{\overline{\pi}^*(p_0)}{q(p_0)}. \tag{9}$$

For any price cap that leaves $\overline{\pi}^*(p_0) \geq 0$, welfare is decreasing in price. Welfare is thus maximized at $p_0 = \underline{p}$. Q.E.D.

It follows immediately that since $\underline{p} < c_0$, price caps can be designed so as to Pareto-dominate cost-plus regulation.[14] The effort level and expected cost induced by PC are compared to those under RORR and CP regulation in Proposition 1.

Proposition 1. The firm's effort under price-cap regulation is greater than that under rate-of-return regulation, which is greater than that under pure cost-plus regulation. The firm's expected cost under price-cap regulation is less than that under rate-of-return regulation, which is less than that under pure cost-plus regulation.

Proof: See the Appendix. Q.E.D.

Proposition 1 is quite consistent with intuition. Price caps are designed to maximize effort by inducing the firm to act as a price taker. Cost-plus regulation induces no effort, since the firm cannot recover its cost of effort. Finally, RORR involves rigid prices in the short run, is cost-plus in the long run, and thus is intermediate between cost-plus and price cap regulation.[15] Not surprisingly, then, the firm's choice of effort under RORR is between that under cost-plus and price caps.[16]

While it is possible to rank the above schemes in terms of the effort they induce, welfare comparisons are ambiguous. Under RORR, (3) can be integrated by parts to yield

$$\overline{S} = S(p_0) + \int_0^{c^U} q(p^U)\,\frac{dp^U}{dc}\,F(c \mid e)dc. \tag{10}$$

Because $dp^U/dc > 0$, RORR generates greater consumer surplus than does pure PC regulation, assuming the same initial price $p_0 = c_0$. RORR offers consumers two benefits: first, it adjusts price closer to marginal cost when profits rise "too" high, and second, because

13 The results of Lemma 1 are similar to those of Cabral and Riordan (1989) in their Propositions 3.1 and 3.2, but Lemma 1 applies for all p_0, not just $p_0 = c_0$.

14 Because welfare-maximization requires expected profits be set to zero, the weight on profits in the welfare function has no impact on Lemma 2.

15 Joskow and Schmalensee (1986) discuss this point extensively.

16 Despite our different modeling of RORR and PC regulation, this result parallels Proposition 4.1 of Cabral and Riordan (1989).

$p_0 = c_0$, there is no possibility of costs above c_0, so a sharing rule never forces consumers to bear responsibility for negative profit outcomes.[17] However, if the price-cap scheme begins with an initial price $p_0 < c_0$—and this is clearly the intent of price-cap regulation—the comparison is in general ambiguous.[18]

5. Sliding-Scale Regulation

This section examines the performance of sliding-scale regulation relative to RORR and to price caps. It is assumed throughout that $L \leq 0$ and $U \geq 0$. A complete characterization is not possible using analytical techniques, but marginal shifts away from RORR or PC and toward SS are examined in Propositions 2 and 3. Proposition 4 shows that profit-sharing, implemented via lump-sum transfers, never produces greater total surplus than price caps. In addition, Proposition 5 provides sufficient conditions for a deadband to be a welfare-improving part of SS regulation.

Proposition 2 addresses the question of whether profit-sharing improves upon rate-of-return regulation.

Proposition 2. Relative to rate-of-return regulation, a small increase in α^U increases welfare for small enough U; for large U the welfare effects of profit-sharing are ambiguous in general.

Proof: See the Appendix. Q.E.D.

Proposition 2 shows that profit-sharing is welfare- increasing for small enough U. This is easy to understand because as U becomes small, RORR approaches cost-plus regulation, which provides no incentive for effort. In this situation, the allocative distortions caused by setting $\alpha^U > 0$ are swamped by the beneficial incentive effects.[19] The next proposition addresses the shift from PC to SS.

Proposition 3. Relative to pure price-cap regulation, welfare can always be increased through a small decrease in α^L and a small decrease in α^U, which jointly leave expected profits unchanged.

Proof: See the Appendix. Q.E.D.

Proposition 3 establishes conditions under which profit-sharing enhances welfare relative

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17 In practice, price-cap regulation allows for price reduction if the firm's costs are so low that the monopoly price is below p_0. (This of course will never happen if drastic innovations are impossible.) As long as the upper bound U on profits is below the monopoly profit level, consumers will experience price reductions in more states of the world under RORR than under price caps.

18 This ambiguity, which parallels the results of Schmalensee (1989), reflects the idea that a price cap sacrifices price flexibility to achieve stronger incentives. My model thus differs sharply from that of Clemenz (1991), who concludes that PCs can always be designed so as to produce higher welfare than RORR. The main reason is that Clemenz's "price caps" have upward price flexibility. See footnote 10 for further discussion of our respective assumptions.

19 For U close to zero, this result holds regardless of the weighting of profits in the welfare function. An increase in α^U always increases profits. Furthermore, as U goes to zero, any increase in incentives must benefit consumers as well, since otherwise they have no hope of a price reduction.

to pure price caps.[20] The basic notion is simple: when $\alpha^U = \alpha^L = 1$, sharing produces a first-order allocative gain, but only a second-order loss in the form of weakened incentives.[21]

It is also worth pointing out that welfare is not increased by adding profit-sharing to a price-cap scheme if profits are returned to customers as a lump sum. This is shown in Proposition 4.

Proposition 4. Relative to pure price cap regulation, profit-sharing with benefits distributed to consumers through lump-sum transfers reduces welfare.

Proof: Consider pure PC regulation with some initial price p_0. While lump-sum transfers ex post have no impact on total welfare, any transfer of profits away from the firm reduces its cost-reducing effort, raising expected costs and reducing expected welfare. Welfare losses are exacerbated if price must be increased to keep expected profits non-negative. Q.E.D.

Proposition 4 provides a rationale for why profit-sharing schemes commonly refund shared earnings to customers via price reductions rather than lump-sum transfers. Note, however, that it need not hold if profits receive little weight in the welfare function, since if profit is unimportant, pure transfers from the firm to consumers raise welfare. Similarly, transfers to particular favored groups of customers might be desired by regulators. Such regulatory preferences may explain the provisions in some state regulations that require shared earnings to be invested in network modernization for specific customer groups.[22]

Finally, I return to the question of the welfare effects of a deadband. In section 4, it was easy to see that the deadband embedded in RORR improves upon pure cost-plus regulation, since it both enhances the firm's incentive to exert effort and economizes on regulatory costs in situations where costs have changed little since the last rate review. Proposition 5 examines the welfare effects of a deadband in the more general case where profit-sharing is allowed. Let Δ be the transaction costs of a rate review; this would include, for example, the organizational costs of consumers, the fees of lawyers and consultants, and the opportunity cost of allocating some of the firm's employees to rate case preparation. Total welfare is now

$$\overline{W} = \overline{S} + \overline{\pi} - \Delta[1 - F(c^L \mid e) + F(c^U \mid e)]. \tag{11}$$

Proposition 5. A deadband, i.e., a pair of parameters L and U with $L \le 0 \le U$, where at least one of the inequalities is strict, enhances welfare if the demand curve is downward-sloping and the transaction costs of rate review are large enough.

Proof: See the Appendix. Q.E.D.

Proposition 5 shows that the allocative distortions created by a deadband must be balanced against the enhanced incentives and the reduced transaction costs the deadband provides.

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20 Because the proposition requires expected profit to remain unchanged, it is clearly not affected by the weight of profits in the welfare function.

21 Proposition 3 is similar to Findings 6 and 7 in Sappington and Sibley (1992), though those authors do not allow for a deadband and they require $\alpha^L = \alpha^U$. In both models, however, the key is that profit-sharing improves allocative efficiency.

22 See Greenstein et al. for details on the various plans.

As long as the demand curve is downward-sloping, allocative distortions are bounded, so a deadband enhances welfare if Δ is large enough. Even if $\Delta = 0$, a deadband might enhance welfare if the resulting allocative distortions are smaller than the incentive effects; this might happen, for example, if c_0 is small enough that the allocative effects of loss-sharing are minor.[23]

To summarize the key results of this section, profit-sharing cannot necessarily improve upon rate-of-return regulation, but it can always offer an improvement over pure price caps, assuming profit-sharing is implemented via price changes. Furthermore, a deadband is a welfare-enhancing component of SS regulation if the transaction costs of rate review are large enough. These results are limited, however, since they only address marginal changes in the amount of profit-sharing. To obtain further insight into the effects of large changes in the extent of profit-sharing, the following section presents the results of a numerical simulation analysis.

6. Simulation

This section reports results of a numerical simulation of the foregoing model of sliding-scale regulation. Its purpose is two-fold: 1) To examine whether sharing rules that are significantly different from $\alpha^L = \alpha^U = 1$ can improve welfare relative to pure price caps, and 2) To study the relationship between changes in exogenous parameters and changes in the welfare-maximizing values of the choice variables.

The simulation uses a linear demand function $q = 10 - p$, with $\psi(e) = e^2$, and considers a range of initial cost levels from $c_0 = 1$ to $c_0 = 9$.[24] The probability distribution on costs is

$$F(c \mid e) = 1 - \left(1 - \frac{c}{c_0}\right)^{de},$$

with corresponding density function

$$f(c \mid e) = \frac{de}{c_0}\left(1 - \frac{c}{c_0}\right)^{de-1}$$

and likelihood ratio

$$\frac{f_e(c \mid e)}{f(c \mid e)} = \frac{1}{de} + \ln\left(1 - \frac{c}{c_0}\right).$$

This density function generates an expected value of cost

$$\bar{c}(e) = \frac{c_0}{de+1}.$$

Thus, d is a measure of the efficiency of the cost-reduction technology. The cumulative

23 Note that the proposition continues to hold if profit receives a low weight in the welfare function, since the deadband retains its important role in reducing transaction costs.

24 The costs of rate review are not included in the simulation, so a deadband is not examined.

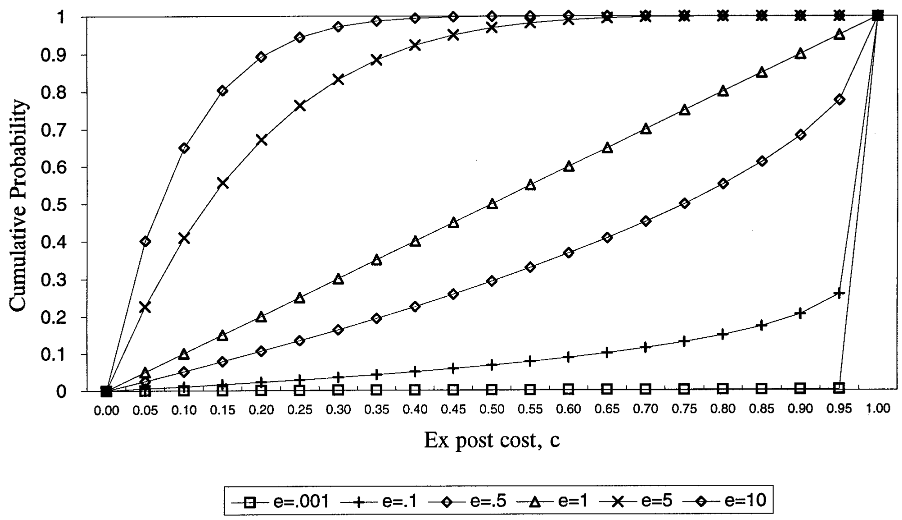
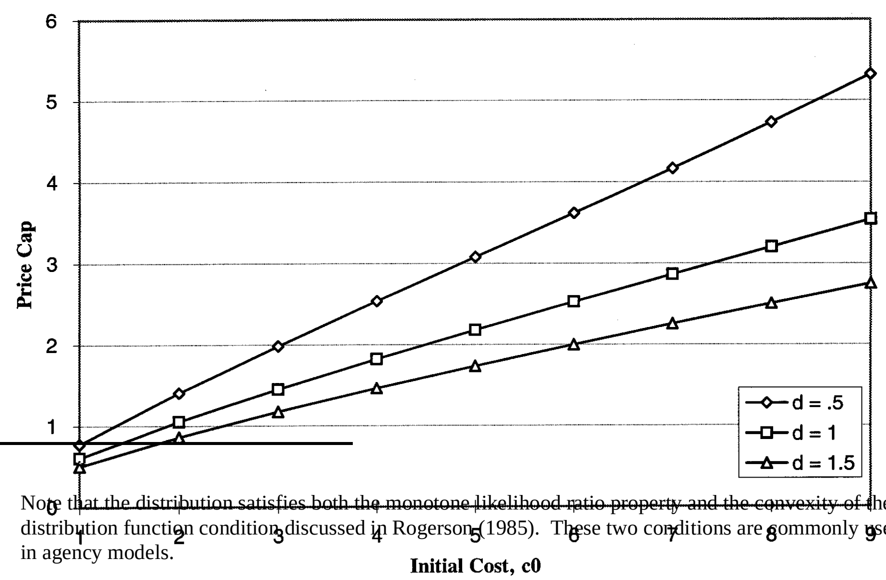


Figure 2. Probability Distribution on Costs for Alternative Effort Levels

distribution is shown in figure 2 for several alternative effort levels.[25] It has the appealing properties that, if the firm exerts no effort then cost is c_0 with certainty, and that expected costs decline monotonically with effort.

Price Cap Regulation

The optimal pure price cap $\underline{p}$ is shown in figure 3 for various levels of initial average cost



25 Note that the distribution satisfies both the monotone likelihood ratio property and the convexity of the distribution function condition discussed in Rogerson (1985). These two conditions are commonly used in agency models.

Figure 3. Optimal Price Caps for Various Cost-Reduction Efficiencies

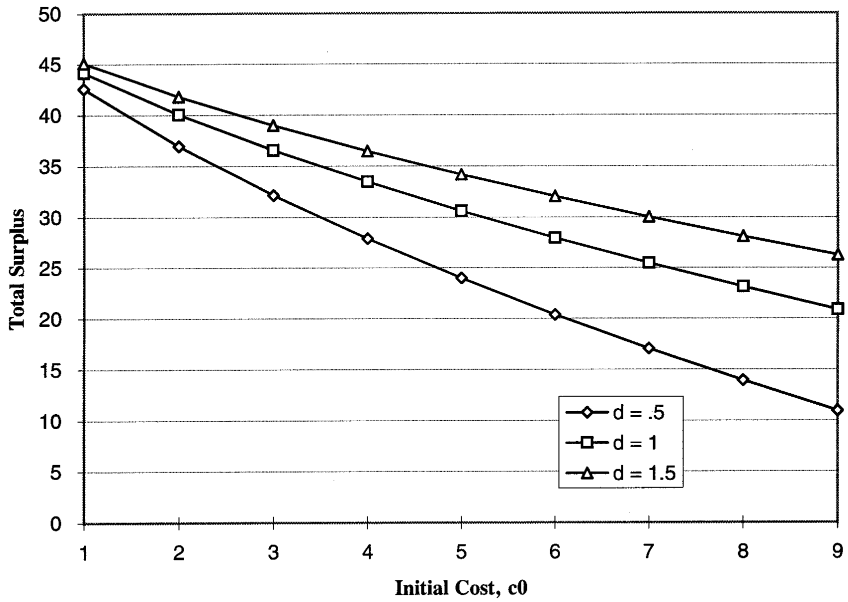


Figure 4. Welfare under Optimal Price Caps

c_0 and efficiency of cost reduction d. While the cap increases with c_0, $d\underline{p}/dc_0$ is well below 1 for all cases examined. In addition, the slope $d\underline{p}/dc_0$ diminishes as the cost-reduction technology becomes more efficient, i.e., as d increases. The corresponding levels of total welfare are shown in figure 4. As one would expect, welfare increases with the efficiency of the cost-reduction technology. An efficient technology also helps offset the welfare-reducing effect of a high initial cost.

Sliding-Scale Regulation

A major purpose of the simulation is to study the characteristics of welfare-maximizing profit-sharing rules. The approach taken here was to first solve for the optimal pure price cap and then, holding the price cap fixed, solve for the welfare-maximizing sharing levels.[26] It should be noted from the outset that monotonic relationships between the level of profit sharing and exogenous parameters such as c_0 and d cannot be expected. Milgrom and Shannon (1994) provide necessary and sufficient conditions for such monotone comparative statics to emerge, and these conditions are not met in my model of sliding-scale regulation.[27]

26 This procedure was adopted primarily to reduce the computational burden of the simulations. Preliminary tests indicated the optimal price level was very insensitive to the presence of profit sharing. Gasmi et al. (1994) also found that the introduction of profit sharing typically has little impact on the optimal price level.

27 The two conditions are: 1) the objective function is supermodular in the choice variables, and 2) the objective function has increasing differences in the choice variables and the exogenous parameters. For smooth functions in $\mathscr{R}^N$, these conditions simplify to restrictions on the cross-partial derivatives of the objective function. In my model, both conditions fail because $\partial^2 W/\partial\alpha^U\partial p_0$ and $\partial^2 W/\partial\alpha^U\partial c_0$ are ambiguous in sign.

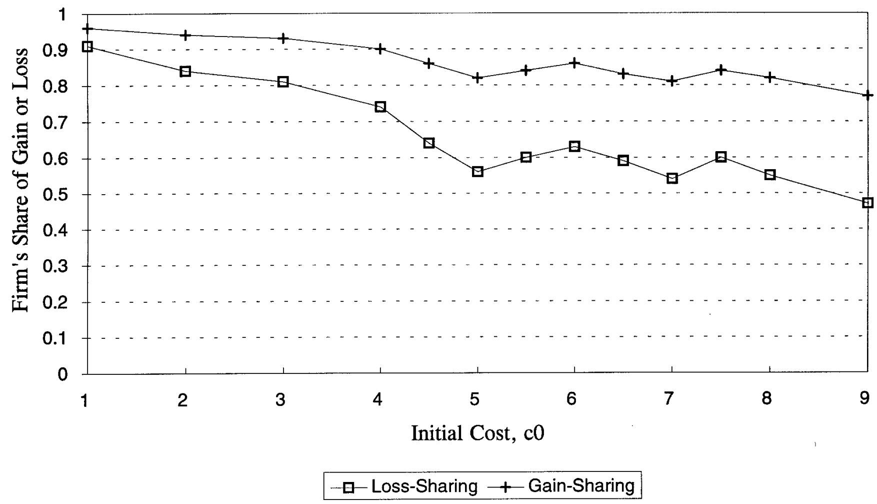


Figure 5. Welfare-Maximizing Sharing Rules ($d = 1$, $L = U = 0$)

The firm's share of gains and losses under welfare-maximizing SS regulation is shown in figures 5 and 6 for various levels of c_0 and d. Several observations are worthy of note. First, in all cases examined, the firm's share of gains, α^U, is greater than its share of losses, α^L; hence, the profit function is convex in observed cost. This convexity may help induce the firm to undertake the risks of investing in cost reduction. Second, loosely speaking, the

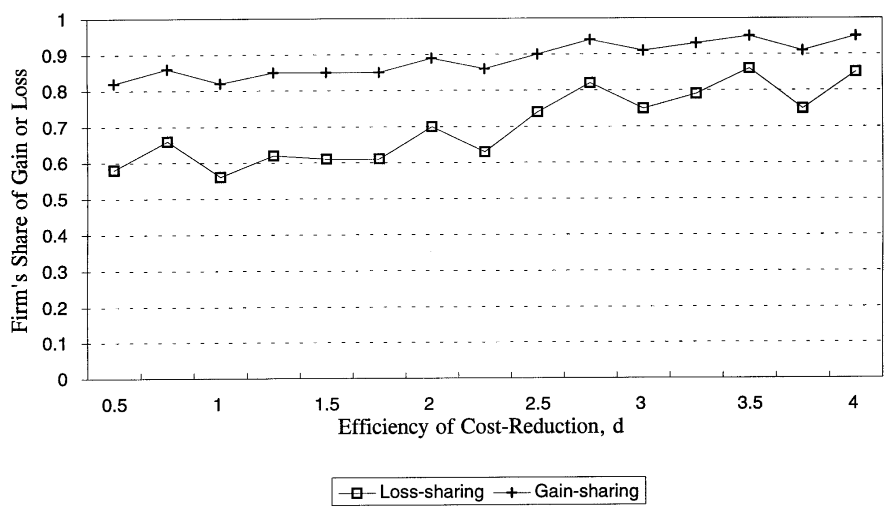


Figure 6. Welfare-Maximizing Sharing Rules ($c0 = 5$, $L = U = 0$)

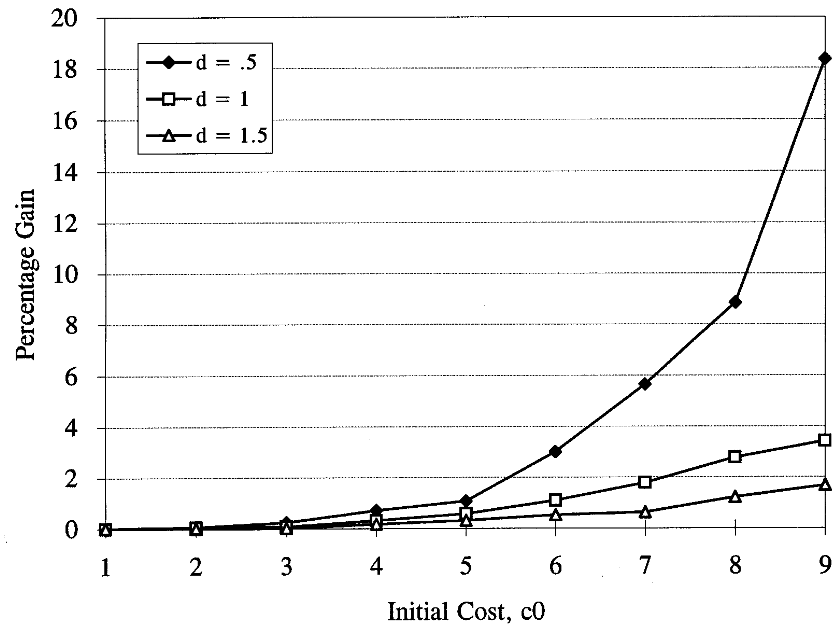


Figure 7. Welfare Gain: Price Caps to Sliding Scale

welfare-maximizing values of α^L and α^U decline with increases in c_0, though the decline is certainly not monotonic. With higher initial cost, there is a wider range of possible ex post cost levels, and hence price flexibility is more important. Third, loosely speaking, the welfare-maximizing values of α^L and α^U rise with increases in d, though again the decline is not monotonic. A more efficient cost-reduction technology reduces the chance that a high cost realization will occur and makes price flexibility less important.[28]

The percentage welfare gain in adding optimal profit sharing to the optimal price cap is shown in figure 7. For low levels of c_0, profit-sharing offers very little gain over pure price caps. The narrow range of possible future costs makes price flexibility unimportant. The benefits of profit-sharing increase with c_0 and decrease with the efficiency of the firm's cost-reduction technology; when $c_0 = 9$ and $d = .5$, SS regulation provides an improvement of more than 18% relative to pure price caps.

The above results contrast sharply with the simulation findings from the adverse selection model of Gasmi, Ivaldi, and Laffont (1994). They find that the sliding-scale rule that maximizes the sum of consumers' surplus and profits is essentially rate-of-return regulation, i.e., a scheme that has $U > 0$ but $\alpha^U = 0$; in addition, they find that price is always greater than cost ex post. These differences stem from two underlying differences in our respective

28 The second and third observations parallel the standard result in adverse selection models that the most efficient type of firm receives the strongest incentives.

models. First, Gasmi et al. redistribute shared profits to consumers via a lump-sum transfer rather than a change in price, so profit-sharing has no allocative efficiency effects. Second, they impose ex post limited liability for even the least efficient firm, so loss-sharing is never a possibility.

It is interesting to compare the qualitative nature of the simulated sharing rules with the sharing plans put into practice. Greenstein et al. (1995) summarize several recent surveys of state incentive regulation plans for telecommunications, many of which include profit sharing. The general pattern they report shows firms' share of profits tends to fall as the level of profits rises; many schemes return all profits above a certain level to ratepayers. This pattern runs counter to the welfare-maximizing policy identified by the simulation. Presumably the political pressures on regulators make it difficult to allow firms to keep a large share of profits when profits are high.

A final case study is provided by the profit-sharing plan used by Medicare for psychiatric hospitals. Under the so-called TEFRA[29] system implemented in 1982, if hospitals reduced their costs below a target level, they could keep 50% of gains up to a maximum of 5% of the target. If costs were above the target, however, the hospital had to cover 100% of the excess. Thus, $\alpha^U = .5 < \alpha^L = 1.0$, a plan that runs counter to the above findings for optimal sliding-scale regulation. Interestingly, TEFRA was modified for 1992 implementation to incorporate loss-sharing provisions symmetric with those for gain-sharing. While the simulation results above suggest that loss-sharing probably should have been even more extensive than gain-sharing, the change represents a big step in the direction of efficiency.[30]

7. Conclusions

This paper has presented a formal model of sliding-scale regulation and its benefits relative to rate-of-return regulation and price-cap regulation. While profit-sharing does not necessarily offer an improvement over rate-of-return regulation, some degree of profit- and loss-sharing outside a deadband improves social welfare relative to pure price-cap regulation. Simulation results show that a significant departure from pure price caps—that is, sharing a substantial portion of profits with ratepayers—may be welfare-enhancing. Furthermore, it may be desirable from a welfare perspective to allow the firm to retain a greater share of gains than of losses, though political pressures may militate against such a policy. Simulation also suggests that the additional welfare benefits of profit-sharing over pure price caps are greatest when the firm's initial cost is high and cost-reducing innovations are difficult to achieve.

While the results of this paper are fairly simple and intuitive, they were obtained under some restrictive assumptions. I assumed a single-product firm in a static setting, with no exogenous shocks to costs or demand. In addition, the regulator was assumed to know the firm's underlying production technology, i.e., there was no adverse selection problem. Finally, I made no attempt to distinguish between capital costs and operating costs; since most sliding-scale schemes use the firm's rate-of-return on capital, this distinction may be

29 This system was created as part of the Tax Equity and Fiscal Responsibility Act of 1982, hence the acronym.

30 For a discussion and critique of the initial TEFRA rules, see Cromwell, Ellis, Harrow and McGuire (1991).

important. A full understanding of sliding-scale regulation will only be achieved by integrating these considerations into the analysis.

Appendix

Proof of Lemma 1: (a) As noted above, under pure price caps, expected profits are $\bar{\pi}(e,p_0) = \int_0^{c_0} (p_0 - c)q(p_0)dF(c \mid e) - \psi(e)$. Then, by the envelope theorem,

$$\frac{d\bar{\pi}(e^*,p_0)}{dp_0} = \int_0^{c_0} [q(p_0) + (p_0 - c)q'(p_0)]dF(c \mid e).$$

By assumption, no drastic cost reduction is possible, and $p^M(0) > p_0$. Thus, revenue is increasing in p_0, so $q(p_0) + p_0 q'(p_0) > 0$. Since $-cq'(p_0) > 0$, expected profits are increasing in p_0. It is clear that if $p_0 > c_0$ then $\bar{\pi} > 0$ and if $p_0 = 0$ then $\bar{\pi} < 0$. Since $\bar{\pi}$ is continuous in p_0, there exists some $\underline{p} > 0$ such that $\bar{\pi}(e^*,\underline{p}) = 0$ and $\bar{\pi}(e^*,p) < 0$ for all $p < \underline{p}$.

(b) Totally differentiating (8) and rearranging terms yields

$$\frac{de}{dp_0} = \frac{-q'(p_0)\int_0^{c_0} F_e(c \mid e)dc}{q(p_0)\left[\int_0^{c_0} F_{ee}(c \mid e)dc - \psi''(e)\right]} < 0. \tag{12}$$

Q.E.D.

Proof of Proposition 1: Suppose the same initial price p_0 holds under all regimes. Let e^{RORR} solve (7), and e^{PC} solve (8). Note that (7) and (8) are identical except that the integral in (8) has a smaller lower limit of integration. Thus, the price-cap firm's expected profits at e^{RORR} are increasing in e. Because $F_{ee}(c \mid e) < 0$, $e^{PC} > e^{RORR}$. This is true a fortiori if the initial price under price caps is less than that under RORR. It is apparent from (7) that $e^{RORR} > 0$, but under cost-plus regulation effort is $e^{CP} = 0$. Thus $e^{RORR} > e^{CP}$. Expected costs are always decreasing in effort because $F_e(c \mid e) \geq 0$. Q.E.D.

Proof of Proposition 2: Under RORR,

$$\left.\frac{d\bar{W}}{d\alpha^U}\right|_{\alpha^U=0} = \int_0^{c^U} \left[(p^U - c)q'(p^U)\frac{[(p_0 - c)q(p_0) - U]}{q(p^U) + (p^U - c)q'(p^U)}\right]dF(c \mid e)dc$$

$$+ \left.\frac{\partial \bar{W}}{\partial e}\frac{\partial e}{\partial \alpha^U}\right|_{\alpha^U=0}. \tag{13}$$

Note that the integral term (the allocative effect $\partial\overline{W}/\partial\alpha^U$) is negative, while the second additive term (the incentive effect) is positive. Thus, in general the sign of (13) is ambiguous. However, if $U = 0$, then $p^U = c$, and the integral term is exactly zero; welfare increases with α^U. Since (13) is continuous in U, profit-sharing is welfare-increasing for small positive values of U as well. Q.E.D.

Proof of Proposition 3: Under pure price-cap regulation, $\partial p^L/\partial c = \partial p^U/\partial c = 0$, and $\partial\overline{S}/\partial e = 0$. Straightforward calculations yield

$$\left.\frac{d\overline{W}}{d\alpha^L}\right|_{\alpha^L=1} = \int_{c^L}^{c_0}\Big[(p_0 - c)q(p_0) - L\Big]\left[1 - \frac{q(p_0)}{q(p_0) + (p_0 - c)q'(p_0)}\right]dF(c \mid e)dc < 0. \tag{14}$$

By the definition of c^L, $(p_0 - c)q(p_0) - L < 0$ for $c > c^L$; thus, the first term in brackets within the integral is negative. Further, if $L \le 0$, then $c > c^L$ implies $p_0 < c$; thus, the second bracketed term within the integral is positive. The integral as a whole is negative, so a small decrease in α^L increases welfare.

Similarly,

$$\left.\frac{d\overline{W}}{d\alpha^U}\right|_{\alpha^U=1} = \int_0^{c^U}\left[\frac{\partial\pi}{\partial p^U} + \frac{\partial S}{\partial p^U}\right]\frac{\partial p^U}{\partial\alpha^U}dF(c \mid e)$$

$$= \int_0^{c^U}\left[(p^U - c)q'(p^U)\,\frac{[(p_0 - c)q(p_0) - U]}{q(p^U) + (p^U - c)q'(p^U)}\right]dF(c \mid e)dc < 0. \tag{15}$$

Since c^U defines the cost level below which earnings exceed U, $p^U - c > 0$ for all $c < c^U$. Thus, the first multiplicative term within the integral is positive. Demand is downward-sloping, so the second term is negative. Since $p_0 < p^M(0)$ by assumption, the denominator of the last term—which is equal to the marginal change in revenue with an increase in price—is positive. Finally, $(p_0 - c)q(p_0) - U > 0$, and the numerator of the last term is negative. Thus, the integral as a whole is negative, and a small decrease in α^U increases welfare. Since $\alpha^L < 1$, profits remain non-negative. Q.E.D.

Proof of Proposition 5: Differentiating welfare with respect to U yields

$$\left.\frac{d\overline{W}}{dU}\right|_{U=0} = \frac{\partial\overline{W}}{\partial U} + \frac{\partial\overline{W}}{\partial e}\frac{\partial e}{\partial U} + \Delta\left[f(c^U \mid e)\,\frac{\partial c^U}{\partial U} + F_e(c^U \mid e)\,\frac{\partial e}{\partial U}\right]. \tag{16}$$

The first additive term is negative, representing the loss of allocative efficiency created when a deadband makes price unresponsive to cost. The second additive term is positive due to the enhanced incentive for cost reduction provided by the deadband. The third additive term is positive because a larger deadband generates fewer costly rate reviews. Thus, if the first term is bounded, there exists some Δ

large enough to make a deadband desirable. Suppressing the dependence of p^U on c, straightforward calculation shows that

$$\left.\frac{\partial \overline{W}}{\partial U}\right|_{U=0} = (1-\alpha^U)\int_0^{p_0} \frac{(p^U - c)q'(p^U)}{q(p^U) + (p^U - c)q'(p^U)} dF(c \mid e)dc$$

$$< \max_c \frac{(p^U - c)q'(p^U)}{q(p^U) + (p^U - c)q'(p^U)}. \qquad (17)$$

The denominator of this last expression is positive, since p^U is less than the monopoly price. Since $q'(p)$ is finite, the numerator is bounded. Hence the size of the allocative effect is bounded, and there exists some Δ large enough that $d\overline{W}/dU > 0$ at $U = 0$. A similar argument can be made for $L < 0$. Q.E.D.

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Appendix D9-1

BCUC ORDER G-51-03
TGI 2004-2008 MULTI-YEAR PBR

(Provided in electronic format only to conserve paper)

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BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-51-03

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Terasen Gas Inc.
(formerly known as BC Gas Utility Ltd.)
for Approval of a Multi-Year Performance-Based Rate Plan
to Set Rates for 2004-2008

BEFORE:	P. Ostergaard, Chair	)	
	R.H. Hobbs, Commissioner	)	July 29, 2003
	R.D. Deane, Commissioner	)	

O R D E R

WHEREAS:

A. In accordance with the determinations from the 2003 Revenue Requirements Decision dated February 4, 2003, Terasen Gas Inc. (formerly BC Gas Utility Ltd.) ("Terasen Gas") applied to the Commission on April 17, 2003 for approval of its Multi-Year Performance-Based Rate Plan to set rates for 2004 to 2008 pursuant to Sections 58 and 61 of the Utilities Commission Act; and

B. Commission Order No. G-29-03 established a timetable for the Negotiated Settlement process which included a Workshop and Pre-hearing Conference on May 15, 2003, followed by Information Requests and Responses; and

C. Negotiations commenced June 9, 2003 and a proposed Settlement Agreement for a 2004-2007 Performance-Based Rate Plan was reached by Terasen Gas, a group of Intervenors and Commission staff; and

D. The Lower Mainland Large Gas Users Association, the Heating Ventilating Cooling Industry Association of B.C., the B.C. Greenhouse Growers Association, the United Flower Growers Co-operative Association and Avista Energy Canada Ltd. filed concerns dissenting from the Settlement Agreement but stated that they were not asking for further public process; and

E. The Commission has reviewed the proposed Settlement Agreement and considers that approval is in the public interest.

NOW THEREFORE the Commission orders as follows:

1. The Commission approves for Terasen Gas the Settlement Agreement for a 2004-2007 Performance-Based Rate Plan, attached as Appendix A.

2. In accordance with the 2003 Revenue Requirements Decision, and by October 31, 2003, Terasen Gas is directed to provide to the Commission a plan for the separation of Terasen Inc. pensions, salaries and expenses.

3. It is open to the parties to pursue any concerns regarding the Terasen Gas Code of Conduct, Transfer Pricing Policy, and Website by way of the Customer Advisory Council forum established by the Settlement Agreement or by the complaint process pursuant to Section 83 of the Utilities Commission Act.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of July 2003.

BY ORDER

Original signed by:

Robert Hobbs
Commissioner

Attachment

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Multi-Year Performance Based Rate Plan for 2004-2007
Terasen Gas Inc.

Negotiated Settlement

Terasen Gas Inc. "Terasen Gas", (formerly BC Gas Utility Ltd.) filed an Application relating to its 2003 revenue requirements and a multi-year PBR in June 2002 that requested that the Commission establish a process for achieving a negotiated settlement of both the 2003 revenue requirements and a multi-year PBR. Commission Order G-63-02 contemplated a two step process for the consideration of the Company's Application for a multi-year PBR. The Order indicated that a full public review of the costs incorporated in the base year rates would be supportive of more efficient negotiated settlement discussions regarding the multi-year PBR. A public hearing was held commencing November 12th, 2002 and the Commission's Decision was issued February 4, 2003. That Decision reviewed the Company's costs and revenues, and established rates for 2003.

The need to proceed in a timely manner with the second step of the process for establishing the multi-PBR was reinforced in the Commission's Decision. The Decision stated:

> "The Commission anticipates that BC Gas will file, early in 2003, a multi-year PBR Application for revenue requirements for 2004 and beyond which incorporates the determinations made in this Decision."

The Company filed its multi-year PBR Application on April 17, 2003. The Commission issued orders G-29-03 and G-38-03 that set out the timetable for the Negotiated Settlement process which included a Workshop and Pre-Hearing Conference on May 15, 2003 followed by the submission of Information Requests by interested parties and responses by the Company. Negotiations commenced June 9, 2003 and these negotiations led to the settlement terms included in this document and its appendices.

Terasen Gas and a group of Intervenors reached this Negotiated Settlement of a Multi-Year Performance Based Rate Plan for the years 2004 through 2007. This Settlement document describes the agreed terms and conditions for the Company's multi-year performance based rate plan and includes a number of detailed appendices that together form the settlement agreement:

- Appendix 1 – a comprehensive listing of issues dealt with in the Terasen Gas application and a number of additional issues that arose during negotiations and their resolution. That document is intended to provide further details of the Settlement and to assist the Commission and all participants by identifying the relevant sections of the Application and Information Responses with respect to each issue, so that any party may review the filed material to understand the resolution achieved.
- Appendix 2 – the details of an expanded annual review process
- Appendix 3 – a description of the capital expenditures true-up process and the end-of-term capital benefit phase-out mechanism

The parties supporting this settlement include the B.C. Health Services, Elk Valley Coal Corporation, the Inland Industrial Group, and the British Columbia Old Age Pensioners Association et al. The representative on behalf of the Lower Mainland Large Gas Users Association, the United Flower Growers Association, the B.C. Greenhouse Growers Association, Heating Ventilating Cooling Industry of B.C. and Avista Energy Canada Ltd., was unable to agree with certain aspects of the settlement document.

A major issue in the negotiations was the proposed term of the agreement. The four-year term commencing January 1, 2004 is one year longer than previous settlements with BC Gas or Aquila. Net restructuring costs incurred after July 1, 2003 will be included in 2004 costs. A key factor in extending the term of this agreement is the expanded annual review process detailed in Appendix 2. The new annual review process will require Terasen Gas to provide considerable information on its current and future year activities, along with statistics on its quality of service provided and its compliance with the code of conduct and transfer pricing policy. The parties agreed that Terasen Gas is responsible for all management and operating decisions of the Company. This settlement and its provisions to provide operating information at annual reviews do not provide for the pre-approval of operating decisions by the parties, ie. no micro-management.

In agreeing to the extended term of this settlement the parties also recognize that the PBR Plan includes other features to reduce the risk of undesirable outcomes, including a mid-term assessment review in year 3, a “trigger mechanism” to review whether the settlement agreement should terminate if the achieved return on equity is greater or less than 150 basis points from the approved level or if there is a serious degradation of SQIs. There is also to be a semi-annual customer advisory council meeting in October prior to the Annual Review and in the following April. The Agreement also includes a “no surprises” term which is to ensure that any significant changes or restructurings at the utility will have been discussed with interested parties.

This PBR Plan has strengthened the incentive for Terasen Gas to control its capital spending on items other than Certificates of Public Convenience and Necessity (“CPCN”). Although the Terasen Gas application included incentives on all capital additions, including CPCNs, the parties agree that CPCN applications should continue to be outside of the incentive formula and approved separately by the Commission. The expected

CPCNs over the term of the agreement, as identified in the Application, are modest in comparison with the substantial projects which were undertaken over the past five years. The base capital will be subject to incentives and productivity requirements as discussed below.

The O & M costs and base capital are subject to an incentive formula reflecting an increasing cost as a result of customer growth and inflation, minus a productivity factor defined as a percentage of inflation. The parties agree to continue to use estimates of inflation based on CPI(BC) as previously undertaken in the last settlement. However, the productivity adjustment has been changed from a discreet value to be 50 percent of CPI(BC) for years 1 and 2 of the settlement and 66 percent of CPI(BC) for years 3 and 4. The parties believe that linking the productivity factor to CPI(BC) will be beneficial for both the ratepayers and the Company since the available productivity will increase as inflation increases and the Company will have limited prospects for productivity if inflation decreases. In particular the existing labour contracts will become a challenge for the Company if inflation falls toward zero. The parties have agreed to a continuation of the 50/50 sharing mechanism of earnings above or below the allowed return on equity, net of incentives. The sharing mechanism creates an alignment between the Company and ratepayers. Net restructuring costs incurred after July 1, 2003 will be included in 2004 costs.

This settlement agreement includes a two-year phase out of the final year capital benefit. The phase out will be two-thirds of the capital benefit in the first additional year and one-third of the final year base capital savings in the second year. This is similar to the treatment of capital variances at the end of the previous 1998/2001 PBR and will maintain the incentive towards achieving efficiency in capital spending throughout the term of the agreement.

Maintaining acceptable levels of service quality is an important aspect of incentive regulation. In this settlement agreement the parties have agreed to an expanded group of ten SQIs, seven of which have specific benchmarks to be achieved and three which will be compared with previous year's results. The agreement also includes two directional indicators. The Company is accountable for its quality of service by reporting on its performance at the annual reviews, with an opportunity for participants to argue to the Commission that Terasen Gas should not be awarded its full financial incentives if the service quality has deteriorated. Participants may also argue to the Commission that the incentive agreement should be terminated if there is a serious degradation of service quality during the term. The details of the service quality indicators are provided in the annual review document (Appendix 2).

Terasen Gas and the participants are interested in incenting the Company to control costs on expenditures which may be only partially controllable by the utility. For example, the parties have agreed to an incentive mechanism with respect to government taxes and fees. In addition Terasen Gas is encouraged to bring forward any new ideas with respect to positive incentives for partially controllable expenses to the annual reviews. The terms of this settlement agreement in Appendix 1 also deal with a number of other technical issues. These include changes to the accounting treatment with respect to transmission pipeline integrity programs ("TPIP") to expense the recurring costs while continuing to capitalize the facility modifications with respect to the integrity program. The settlement agreement also identifies that any changes in regulatory treatment resulting from changes in GAAP will require Commission approval.

Incentives for load building initiatives may be developed and submitted prior to an annual review. The incentive would only apply to initiatives which are determined to be beneficial to ratepayers after a DSM like assessment of each initiative.

During the term of the PBR, the Company may apply to the Commission to undertake restructuring or other efficiency initiatives that require an incentive or payback term extending beyond the term of the PBR agreement. The application would set out the accounting mechanism and the performance/prudence criteria to be used to decide on the ultimate disposition of the incentive account.

At each annual review commencing November 2003, the Company will update its forecast of customer additions, use per account and industrial revenues. The impact on revenues resulting from the updated forecasts will be flowed through in delivery rates in the following year. The settlement also provides for the flow through of the impacts of changes approved by BCUC orders and exogenous factors.

Finally, the currently approved capital structure for Terasen Gas will continue, as will the quarterly reviews of natural gas commodity costs.

For further information on all issues please refer to the settlement terms in Appendix 1.

Attachments

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APPENDIX 1

Terasen Gas Inc.
PBR Plan 2004-2007
Settlement Terms

Application 2004-2008 PBR Plan	Resolution
Term Terasen Gas proposes a five year term for the PBR Plan	A four year term from 2004 to 2007 was accepted.
Productivity Page C-25 proposes a results-based adjustment factor of 0.75% each year from 2004-2008 for O&M and Net Gas Plant in Service.	The adjustment factor will be 50% of CPI for 2004 and 2005, and 66% of CPI for 2006 and 2007. See O&M and Capital Additions Forecast sections below.
Inflation CPI (BC) will be used to adjust the controllable expenses as described on page C-10. Rates will be set prospectively, and as in the 1998 plan, the rates will not be modified to reflect actual CPI (BC). CPI (BC) is forecast as 1.8% for 2004 and 2% for 2005-2008 in Section H, Tab 3, page 2.2. The Annual Review will update the inflation forecast for the upcoming year as described in Section H, Tab 9, p. 1 and BCUC IR10.1, but there will be no true up to actual CPI(BC). Alternative inflation indices were discussed in BCUC IR 10.2 and Elk Valley Coal Corporation IR#2, Questions 2-4.	CPI (BC) accepted as filed.
Customer Growth The Annual Review will update the customer count for the actual number of customers at the start of the year and forecast customer growth for the upcoming year as described in page F1 and BCUC IR 9.1.	Accepted as filed-same as 1998-2001 PBR.
Revenues Revenue categories identified on pages C-13 to C-14 include amounts received from sale and delivery of gas, transportation service, revenues received under tariff supplements, $85 from application for service and revenues from account transfers. Revenues will be forecast each year and the company is at risk within the year for variances in industrial revenues, customer additions, applications for service and account transfers. Throughput variances for residential and commercial customers in rates 1, 2 and 3/23 will be subject to RSAM. Variances in Burrard Thermal and SCP revenues will be deferred and amortized. Pages F-1 to F-8 state that the forecast process has a customer additions forecast, an average use per account forecast and an industrial forecast. A 2003 industrial survey will be presented at the 2003 Annual Review. The residential use per account of 108 GJ was used for 2003 and in the	Forecast process is acceptable. Earnings variances relating to at risk revenue items will be included in the Earnings Sharing Mechanism.

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Application for 2004. The use per account for rates 1, 2, 3 and 23 will be reforecast at the 2003 and subsequent Annual Reviews. Other revenues of Centra Gas (PCEC) Wheeling Agreement and SCP third party revenues will be forecast each year at the Annual Review. Late payment revenue will be adjusted to the same formula as O&M expenses. Page C-14 indicates that load-building programs will be brought forward either at or before Annual Reviews. These are separate from DSM programs as confirmed in BCUC IR 7.2	
Gas Cost Section H, Tab 8, p. 1 states that the cost of gas used under the PBR will be based on the approved unit gas costs prevailing at the time the volume and revenue forecast is made. Page C-19 proposes the continuation of GCRA and GSMIP.	 Accepted as Filed
O&M Section H, Tab 9, p. 1 proposes that O&M expense for 2004-2008 be determined by a formula-based approach that starts from a base of the 2003 Decision O&M escalated by growth in customers and inflation less an adjustment factor of 0.75%. The O&M formula on Section H, Tab 9, p. 1 is: [Base Cost x(1+Growth) x (1+Inflation-0.75% adjustment factor)] Page C-13 proposes that pension and insurance costs will be forecast each year with variances deferred for flowthrough amortization over one year. Vehicle and Coastal Facilities Lease are added (not part of O&M formula) Pipeline Integrity Costs-if a planned capital expenditure is to be funded through O&M then page C-19 proposes that the allowed O&M be increased.	 Accepted for 2004 – 2007 with adjustment factors of 50% CPI in 2004 and 2005, and 66% CPI in 2006 and 2007. Beginning in 2004, ongoing pipeline integrity costs are to be expensed as O&M and a levelized adjustment will be made to the base O&M in the formula for years 2004-2007. Facilities retrofits will continue to be treated as CPCNs throughout the term. See also Capital Additions Forecast.
Overhead Page G-5 proposes a 16% overhead per year from 2004-2008, calculated consistent with the response to BCUC IR 11.1 and Section H Tab 9 Page 2 of the Application.	 Accepted as Filed except that the amount of gross O&M not subject to Overheads Capitalized will be escalated by the O&M formula. The amount not subject to overhead capitalization is the sum of $19,373,000 (Section H, Tab 9, Page 2) and the levelized incremental pipeline integrity O&M expenses of $5,505,000.
Net Gas Plant in Service Formula	

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Section H, Tab 3, p. 2 proposes that Mid-year NGPiS for 2004-2008 be determined by a formula-based approach that starts from a base of the 2003 Mid-year NGPiS escalated by growth in customers and inflation less an adjustment factor of 0.75%. The NGPiS formula on Section H, Tab 3, p. 2 is: Current Mid-year NGPiS=(Prior Mid-year NGPiS/customer) x (Forecast Average Number of Customers in Current Year) x (1+Inflation-0.75% adjustment factor) 2003 Mid-year NGPiS is based on actual 2003 opening NGPiS and the projected 2003 year end NGPiS from the fall 2003 Annual Review. Formula-based values of NGPiS, accumulated depreciation, CIAOC, net plant additions are not rebased during the five year PBR.	The Net Gas Plant in Service formula approach was not accepted. See Capital Additions Forecast.
Capital Additions Forecast Section H, Tab 3, pp. 2.2 to 2.4 and BCUC IR 2.2 show gross plant additions are back-calculated in several steps from the formula-based mid-year NGPiS and forecast retirements. Forecast retirements are the same as the amounts in last year's PBR proposal.	<u>Base Capital Expenditures.</u> As per BCUC IR 4.6, use formulas based on customer additions and average number of customers. Using (1+CPI (BC)-Adjustment Factor). Base capital expenditure amounts will not be rebased to actual amounts during the term. For rate setting in subsequent years the formula base capital expenditures from the prior years will be adjusted for projected customer counts and trued up for actual customer counts as this information becomes known. The cumulative difference over the four-year term between the trued-up formula based capital expenditures and actual base capital expenditures will be subject to a phase-out of the benefits of 2/3 in the year after the term and 1/3 in the second year after. An example of the capital true-up process and capital benefits end-of-term phase-out is attached as

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	Appendix 3. <u>Capitalized Overhead</u> 16% of gross O&M calculated by formula, consistent with the response to BCUC IR 11.1 and Section H Tab 9 Page 2 of the Application. The levelized O&M increase for ongoing pipeline integrity program expenditures will not be subject to overheads capitalized. <u>CPCN Additions</u> CPCN expenditures are excluded from the capital formula. Except in very unusual circumstances, CPCNs will not be filed for projects below $5 million. Transmission Pipeline Integrity CPCNs will be limited to retrofits, which BCUC IR 23.2.1 (2003 Revenue Requirement Application) showed as $2.8 million in 2004 and $3.0 million in 2005. CPCN expenditures to be included for rate setting purposes will be only for those projects which have been approved by the Commission and are projected to be in service prior to the year for which rates are being set. The revenue requirement effect of variances between projected and actual CPCN expenditures for those projects being added to rate base will be taken into account in the Earnings Sharing Mechanism.
15% Plant Additions Benefit Factor Appendix C-A-2. p. 2 proposes that the current year plant additions savings (actual versus NGPiS formula) be multiplied by a factor of 15% to represent the average avoided annual revenue requirement. An example is provided in	 Accepted for application only to base capital additions for the end-of-term capital

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BCUC IR 1.9.2 showing a levelized saving of 13.21%. The 15% factor provides for the possibility of plant accounts with higher depreciation rates or higher cost of capital in the future.	benefits phase-out except that the factor should be 14%.
Depreciation Rates Section H, Tab 4 deals with the calculation of depreciation expense for 2004 to 2008. Depreciation rates for Meters, Meter Installations and Regulators and Computer will be adjusted effective January 1, 2004. Under the PBR proposal, the accumulated depreciation used in setting rates each year in the Annual review process will arise from the NGPiS calculation, as described in BCUC IR 2.1. Retirements to be used in the accumulated depreciation calculation will be forecast each year for the Annual Review.	 Accepted as Filed.
Restructuring Deferral Account Pages C-15 and C-16 propose that after the PBR Plan is approved, investments in restructuring will be deferred and recovery will commence in 2004 from actual savings before any sharing. If there is a debit balance in the deferral account in 2008 then it is applied against the full term efficiency incentive. In LMLGUA IR 13, the Company confirmed that if it incurs restructuring costs and efficiencies do not materialize then the restructuring costs are borne by the Company. In BCUC IR 1.11.5 the Company proposes a non-rate base deferral account. In BCOAPO IR 4.1 the Company proposes that the revenue requirements would not be increased by the amount of the deferral account. In LMLGUA IR 4.1 the Company anticipates that a definition of what is to be included in restructuring costs would be included in the negotiated settlement document. The Company proposed items to be included are in BCUC IR 1.11.1. On page C-15 and in BCUC IR1.11.2 and BCOAPO IR 4.1 and 4.2 the Company states that positive variances from the allowed ROE will first be used to offset the costs included in the restructuring deferral account prior to sharing.	 All restructuring costs incurred during the Term are to be treated as normal expenditures. Specific restructuring initiatives requiring longer term recovery or providing longer term benefits beyond the end of the Term can be brought forward by the Company for consideration at any Annual Review. Net restructuring costs incurred by the Company between July 1, 2003 and December 31, 2003 will be captured in a deferral account, to be recovered as a 2004 expense. Net restructuring costs refers to the netting off of savings the Company realizes in 2003 from restructuring activities. The deferral account will be non-interest bearing non-rate base.
Full Term Efficiency Incentive Page C-16 and Appendix C-A-2, pp. 1-4 describe FTEI as motivating new efficiencies and provides for retaining savings for five years after the investment is made to repay the cost of the initial investment before savings are shared with customers.	 The FTEI is not accepted. However, there will be a capital benefits phase-out at the end of term as described in the Capital Additions Forecast section above. .

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Sharing Mechanism

Appendix C-A-2, pp. 1-4 describes and provides an example of the sharing mechanism for savings in net O&M, the gross plant additions benefit and industrial revenue variances. The allocation of savings to the Restructuring Deferral Account and the FTEI is also described.

Pages C-15 and C-16 propose that sharing commence on January 1, 2004 with 50/50 sharing of earnings above or below the allowed ROE, net of GSMIP, the DSM Achievement Incentive and other incentives. The customers' portion of the sharing will be projected at Annual Reviews and provided to customers by a rider in the following year. The customers' actual portion of sharing shall be determined after year end and variances from projections provided to customers by a rider in the following year. Sustained (two-year average) return that is 200 basis points above or below the allowed ROE triggers an Off-Ramp review.

</td><td>

The 50/50 sharing mechanism is accepted based on the difference between the allowed and actual ROE (net of GSMIP, DSM Incentive, load building and incentives for partially controllable items) using the common equity component of the actual rate base.

See Trigger Mechanism.

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Deferred Charges and Amortization

Pages G-6 to G-7 seeks continuation for 2004 to 2008 of:

- Deferred interest account to collect interest expense variances from forecast short-term debt rates and from forecast long term debt rates, principle, timing of issues and long term debt issue costs.
- DSM incentive grants for deferral of grants of up to $1.5 million per year. BCUC IR 7.2 explained that the deferral account would only be used to collect incentive payments and rebates to customers. Costs associated with advertising (including awareness programs), program promotion, program design, administration, research and evaluation would be O&M expenses.

Additional requests:

- Amortize over 5 years commencing in 2005, the deferred 3rd party revenues arising from the cancellation of PG&E contract net of any mitigation revenues received.
- Deferral of variances in pension expense and insurance expense from forecast.
- Deferral of the costs of the PBR Application and amortize over 5 years.

Section H, Tab 3, pp. 6.1 to 6.6 requests the following treatment:

- Deferred interest is amortized over three years.
- Market Rebate Incentive-Water Heater Grants are continued until final year of amortization in 2004.
- NGV Conversion Grants with continued additions as approved by Orders G-98-99 and G-7-03 and five year amortization.
- 2003 Revenue Requirement with five year amortization.
- 2004-2008 Revenue Requirements with accumulation of costs and five year amortization.
- DSM program to continue with expenditures of $1.5 million per year for 2004-2008 and three year amortization.
- DSM-DRIA to continue with three year amortization.
- Property Tax Deferral with continued accumulation of variances between forecast and actual with three year amortization.
- GCRA and GCRA Interest with continued recording of interest on

</td><td>

Proposed deferral accounts and amortization periods are acceptable.

A DSM assessment report should be provided at the Annual Review of proposed programs for the upcoming year and an analysis of existing programs.

</td></tr>
</table>

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GCRA variances from forecast. Amortization in accordance with Orders No. G-124-00, G-134-01 and G19-03. • RSAM will continue to accumulate differences between forecast and actual use rate of RSAM customers per year from 2004-2008. Any RSAM additions are amortized over three years. Variances between forecast and actual balances will accumulate short-term finance costs. • BC Hydro Services Agreement Costs with continuation of two year amortization by 2003 Decision and Order G-7-03. • Coastal Facilities with continuation of five year amortization by Order C-14-98. With deferral of costs approved by Order C-14-98 and two year amortization by 2003 Decision and Order G-7-03. • ABC-T Project Requirements Phase with two year continued amortization commencing in 2003 by Order G-24-02. • Burner Tip Service with continued one year amortization by 2003 Decision and Order G-7-03. • Earnings Sharing Mechanism as an amortization of the January to February 2003 refund over the remaining March to December 2003 period by 2003 Decision and Order G-7-03. • Salmon Arm Reinforcement with continued amortization by Order G-26-00. Final year of amortization in 2003. • NGV Compression Equipment Recovery with continued 10 year amortization by Order G-143-99. • 2001 Rate Design with continued amortization over three years starting in 2002 by Order G-116-01. • Overheads Change-Income Tax Refund and CIAOC Software Tax Savings/OH Change with continued amortization over five years by 2003 Decision and Order G-7-03. • Other Post Employment Benefits with continued regulatory accounting treatment by Order G-7-03. • Deferred 2000 SCP Cost of Service with amortization over five years by Orders G-135-99 and G-7-03 and 2003 Decision. • SCP Net Mitigation Revenue and SCP West to East Transmission with continued five year amortization by Orders G-124-00, G-123-01, G-7-03 and 2003 Decision. • SCP PG&E Contract Cancellation with forecast lost revenue per Letter L-48-02 and requested amortization over five years commencing in 2005. • CCT Deferral with continuation of five year amortization starting in 2003 by 2003 Decision and Order G-7-03 of deferred credit recorded by Orders G-85-97 and G-48-00. • CCT Assessment with amortization period of three years by 2003 Decision and Order G-7-03.	

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Working Capital Section H, Tab 5, p. 1 proposes that Gas in Storage and Transmission Linepack and All Other Working Capital will have a revised forecast at the Annual Review. Cash Working Capital will use lead/lag methodology from the 1992 Decision with changes from the 2003 approved lead or lag days currently in rates brought forward each year as necessary. In BCUC IR 11.2 the Company discusses using a formula to calculate cash working capital based on the mid-year NGPiS.	Accepted as filed.
Finance, Accounting and Tax Issues Pages G-1 to G-6 propose: • New long term debt issues of $850 million for 2004-2008 with an expected rate of 7%. A 2003 long-term debt issue of $150 million for 2003. Debt expense to be reforecast at each Annual Review as described on page C-12. • Short term debt rates of 4% for 2004 and 5% for 2005-2008. Debt expense to be reforecast at each Annual Review. • Any changes in GAAP would be treated as flowthrough items. • A report will be filed on the separation of BC Gas Inc. pensions, salaries and expenses from BCGUL. The Corporate Centre is expected to have 40-45 employees. Forecast O&M is consistent with the 2003 Decision and the amounts charged by the corporate Centre to BCGUL will be consistent with the 2003 Decision.	Accepted, but any changes in regulatory treatment resulting from changes in GAAP will require Commission approval.
Regulatory Accounting Methodologies Page C-19 proposes the continuation of GCRA/RSAM accounts, taxes payable method for income taxes, regulatory treatment for CPCNs from the 1998-2001 PBR Plan, accounting for certain assets and rate stabilization accounts on a net of tax basis, accounting for property, plant and equipment to include overhead and AFUDC. Approved depreciation rates are used. The current accounting treatment of property, plant and equipment retirements will continue.	Accepted as Filed.
Taxes Page C-13 proposes a deferral account to record variances in property taxes, income tax rates, LCT rates, and any new government tax expenses, charges and levies. Amortization over three years as a flowthrough item. At the Annual Review a forecast of income tax and LCT rates and other tax expenses for the following year will be provided and customers' rates for that following year will be determined on the basis of that forecast.	Accepted as Filed.
Exogenous Factors Exogenous Factors are described on page C-16 as items beyond the Company's control that will be adjusted in rates (flowthrough). These factors include judicial, legislative or administrative changes, orders or	Accept the arguments of Terasen Gas and accept same practice as 1998-2001 PBR.

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directions, catastrophic events, bypass or similar events, major seismic incident, acts of war, terrorism or violence, changes in generally accepted accounting principles, standards and policies, changes in revenue requirements due to Commission directions. In BCUC IR 1.5, the Company lists the flow through items and exogenous factors and discusses the merits of fixing an expense and allowing the item to be "at risk". The Company believes that partially controllable items should be evaluated on an item by item basis and considered in the context of the overall PBR.	
Service Quality Indicators Appendix C-A-1, pp. 7-14 discusses benchmarks for proposed SQIs. Appendix C-A-1, p. 5 proposes a benchmark based, where possible, on a three year history at the beginning of the PBR that is maintained throughout the PBR period. <u>Proposed SQIs</u> — <u>Benchmark</u> Response Time to Site for Emergency Calls — 21.1 minutes % of Responses within 30 Seconds -Emergency — 95% % of Responses within 30 Seconds-Non-Emerg — 75% Trans System Annual Reportable Incidents — 2 Reportable/yr % of Customer Bills Meeting Performance Criteria — Score 5.0 or less Meter Exchange Appointment Activity — 92.2% met <u>Directional Indicators</u> — <u>Three Year Average</u> Number of Third Party Damages — 1,219 Leaks per Kilometre of Distribution Mains — 0.0041 BCUC IR 1.10.7 states whether or not the achievement level for SQIs should be used to qualify the Company for an incentive should be dealt with similar to the 1998-2001 PBR. Page 13 of that PBR stated that SQIs will be reviewed at Annual Reviews and participants can make submissions to the Commission that a deviation from a benchmark is significant enough that it should limit incentive payments to the Utility.	Refer to the SQI section in the Annual Review document (Appendix 2)
Trigger Mechanism Page C-18 proposes that a full regulatory review is triggered if the two-year average achieved ROE after sharing exceeds or drops below the allowed ROE by 200 basis points or if there is a serious degradation of Service Quality Indicators. LMLGU IR 21 clarified that the two-year average refers to two consecutive years and in IR 32 the Company expressed the belief that "serious degradation" cannot be defined in a manner that would foresee all circumstances.	A Commission review of the PBR Plan can be requested by any party if the achieved ROE after earnings sharing varies from the allowed ROE by 150 basis points in any year of the term.
Annual Review The process for the Annual Review and rate setting for the following year is described in BCUC IR14.1 as being similar to the 1998-2001 PBR as adjusted for 2004-2008 PBR Plan formulas, SQIs, plant additions.	Expanded 1998-2001 PBR Annual Review process is acceptable. See attached.

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No Surprises	Terasen Gas is to advise all parties of any major changes planned for the Utility and nothing in this settlement provides Terasen Gas with any approval to change its business practices to the detriment of customers. For example, the spin off of significant operations, such as those outsourced to CustomerWorks would require disclosure prior to undertaking.
Mid-Term Assessment Review Page C-18 proposes that a review be held prior to the end of the third year (2006). If there are unintended outcomes or deterioration in service quality, the parties can jointly address a cure. LMLGUA IR 12.1 describes the Mid-Term Assessment Review as an expanded Annual Review.	The proposal is acceptable.
Customer Advisory Council (CAC) (This item was not addressed in the Application)	A customer advisory council will be established which meets twice yearly to deal with any customer issues that have arisen during the year. The purpose of the CAC will be to provide a non-binding forum for customer groups and the Company to communicate and deal with customers' concerns constructively and proactively. One of the meetings will be held in advance of the Annual Review to provide an opportunity for customers to raise issues again at the Annual Review which have not been satisfactorily resolved in the CAC process. The Company's representatives on the CAC will comprise of the President, Vice President of Marketing and Vice President of Regulatory Affairs. A record of the meetings will be kept and made available upon request.
Equity Thickness	

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Page G-1 confirms that the Company finances its assets with a mix of debt and equity following the Commission's approved capital structure of 33% common equity and 67% debt.	The equity component is consistent with the 2003 Decision and is acceptable. This does not preclude the Company from making an application to the Commission for a variation of its equity thickness if appropriate.
Load Building <u>Company proposed incentives around load building initiatives.</u>	Concept of incentives for load building initiatives accepted, subject to DSM-like assessment (including net present value of expected revenues and costs) of each initiative.
<u>Company proposed framework of specific load building program based on increased penetration for gas cooking, clothes drying and water heating appliances. See attachment. Company may develop other initiatives during the Term.</u>	A DSM-like assessment (including net present value of expected revenues and costs) should be provided at or before Annual Review before initiative starts.

<u>**Other Items**</u>	Resolution
<u>**Partially Controllables**</u> <u>Stakeholders expressed interest in exploring positive incentives around partially controllable expenses. The Company was also interested.</u>	Company to have a positive incentive around provincial and municipal government taxes, fees and expenses. Details of an incentive respecting property taxes were agreed. See Appendix 5.

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	Company or interested parties (intervenors/Commission staff) to bring forward any new ideas around positive incentives for partially controllable expenses to Annual Reviews.

APPENDIX 2

Annual Review
of the
Terasen Gas 2004 — 2007 PBR Settlement (the Settlement)

Annual Reviews and Rate Adjustments

For each year of the Term of the Settlement, the Commission will conduct an Annual Review with Terasen Gas and interested parties. The Annual Review is a proceeding for purposes of participant cost awards.

The Annual Review has the following objectives:

- ♦ To inform the Commission and interested parties about the activities of Terasen Gas;
- ♦ To review Terasen Gas performance under the Settlement, including its costs, service levels and future plans;
- ♦ To identify any concerns regarding the proposed activities of Terasen Gas for the coming year;
- ♦ To attempt to obtain consensus on issues that must be decided by the Commission in advance to set rates for the next year; and
- ♦ To determine if there has been any action by Terasen Gas that may justify a reduction in any portion of the Terasen Gas shareholder incentive payments pursuant to the Settlement.

The Annual Review

At the Annual Review to be held in November of each year beginning in 2003 through 2006, Terasen Gas will present projections for the year that is ending and forecasts for the next year. For the year that is ending, Terasen Gas presentation will include projections of the following:

- ♦ Utility volumes and revenues;
- ♦ Utility expenses;
- ♦ Year-end plant balances and other rate base information;
- ♦ Deferral account balances and amortization;
- ♦ Year-end customers and other cost driver information;
- ♦ Utility earnings;
- ♦ Material efficiency measures or investments, except where the Commission determines that public disclosure of such information at the Annual Review may harm Terasen Gas business interests and such harm outweighs the public interest in public disclosure; and
- ♦ Service Quality Indicator results.

For the next year, Terasen Gas presentation will include forecasts of the following:

- Customer growth;
- Inflation;
- Utility volumes and revenues;
- Utility expenses (determined by the PBR formula plus flow through items);
- Utility capital expenditures (as determined by the PBR formula);
- Plant balances, deferral account balances and amortization to be included in rates;
- Savings and costs of efficiency measures that may materially affect Terasen Gas operations, costs or services, except where the Commission determines that public disclosure of such information at the Annual Review may harm Terasen Gas business interests and such harm outweighs the public interest in public disclosure; and
- Savings and costs of proposed efficiency measures for specific restructuring initiatives requiring recoveries or providing benefits beyond the expiry of the Term.

Cost drivers for the next year will be updated to reflect the most recent forecasts. The customer addition related cost drivers for the next year will also be updated for projected variances between actual customer growth in the past year and the customer growth that had been forecast for that year.

Each year, Terasen Gas will file its updated five-year major capital project plan. The plan will include a system-wide analysis showing the following:

- Peak load projections
- Areas of capacity shortfall
- Projects for system modification or expansion
- Cost projections for regular capital and CPCNs
- Scheduling of projects

The plan will indicate CPCNs that may be needed in future years.

At the Annual Review, Terasen Gas will also review the following:

- Expenditures of Terasen Gas, if any, related to Terasen Gas (Vancouver Island), identifying those expenditures related to efficiency initiatives and related benefits achieved or forecast to accrue to Terasen Gas;

- Any initiatives that Terasen Gas proposes to undertake or has undertaken that may materially affect Terasen Gas operations, costs or services in a manner not anticipated or disclosed during the Negotiated Settlement Process, except where the Commission determines that public disclosure of such information at the Annual Review may harm Terasen Gas business interests and such harm outweighs the public interest in public disclosure;

- Service Quality Indicator results;

- Compliance with Terasen Gas Code of Conduct and Transfer Pricing Policy;

- Compliance with Commission directives and other regulatory requirements relevant to the Settlement;

- Opportunities, if any, to establish incentives that would assist Terasen Gas to reduce its non-controllable expenses; and.

- The number and types of customer complaint calls to CustomerWorks pertaining to the service provided by Terasen Gas.

Terasen Gas will hold its first Annual Review in November of 2003. At that Annual Review forecasts for 2004 will be presented, together with the projected number of customers at January 1, 2004 and projected plant balances and other rate base information as at January 1, 2004. Cost drivers for 2004 will be updated to reflect the most recent forecasts for 2004. Rates for 2004 will be set by the Commission based on the projected opening rate base for 2004 and the forecasts for 2004 as agreed upon by the participants or as subsequently determined by the Commission. Three weeks before each Annual Review, Terasen Gas will provide interested parties and the Commission with: (1) the projections and forecasts to be presented by Terasen Gas at the Annual Review; (2) information addressing issues of concern previously communicated to Terasen Gas by interested parties; and (3) a report on the results of the uncontrollable / partially controllable expenses for which an incentive mechanism has been established. Parties may submit information requests and Terasen Gas will respond to those requests before the Annual Review.

In regard to projected year-end earnings in the November Annual Review, Terasen Gas will provide an update in April or May once actual results have been determined and adjustments will be made at the following year end. Incentives will be trued up to the actual results at that time.

Service Quality Indicators

Service Quality Indicator results will be reviewed at the Annual Review together with a discussion of any specific initiatives undertaken to improve the SQIs or any emerging changes in customer practices that are affecting or may affect SQIs during the Term of the Settlement.

Principle:

Maintenance of existing high levels of service quality is an important feature of this Settlement. The parties recognize that variance in these statistics may occur due to random events or events beyond the full control of Terasen Gas.

Process:

- Service Quality Indicators will be reviewed at the Annual Review in November of each year.

- Participants will be given an opportunity to argue whether a deviation from the benchmark for any of the Service Quality Indicators is significant enough to establish that service quality is deteriorating generally or in specific areas.

Service Quality Indicators:

The parties to agree to the following SQIs and benchmarks:

1.	Response time to site from time of dispatch for emergency calls	21.1 minutes
2.	Percent of responses within 30 seconds by a person for an emergency call	95%
3.	Percent of responses within 30 seconds by a person for a non-emergency call	75%
4.	Transmission system annual reportable incidents	2
5.	(a) Percent of customer bills produced meeting activity criteria	5[1]
	(b) Percent of transportation customer bills accurate	99.5%
6	Percent of meter exchange appointments met	92.2%
7.	Percent of time when transportation meter measurement first report deviates less than 10% when compared to billable amount[2]	90.0%[3]

The parties agree that the SQIs are intended to track Terasen Gas service quality, but acknowledge that the final three SQIs listed below in particular can be influenced by high gas costs and other events beyond the control of Terasen Gas. The three SQIs listed below will be compared to previous years performance, recognizing the impact of events beyond the control of Terasen Gas.

[1] The benchmark of 5 refers to the average of the formula results for the following three submeasures, where PA refers to the actual percentage achieved for each submeasure:

	Submeasure	Formula	Benchmark PA	Benchmark Formula Result
1.	Percentage of bills accurate based upon input data	(100%-PA)*5000	99.9%	5.0
2.	Percentage of bills delivered to Canada Post within two days of date that the statement file is created	(100%-PA)*100	95%	5.0
3.	Percentage of customers billed within two business days of the scheduled billing date	(100%-PA)*100	95%	5.0

[2] Includes both daily and monthly meter measured transportation customers

[3] Calculated on a weighted average based on the number of GJ consumed by each transportation customer

8. Independent Customer Satisfaction Survey

9. Number of Customer Complaints to the BCUC

10. Number of prior period adjustments regarding transportation customer measurement data.

The parties also agree to establish the following directional indicators:

- Leaks per kilometre of distribution mains
- Number of third party distribution system incidents

<u>Annual Evaluation:</u>

- Directional indicators will be given a lesser weight in considering Terasen Gas service quality performance.

- The onus of establishing that a benchmark has been met or why it is reasonable that it was not met rests with Terasen Gas.

- Each SQI will be evaluated on its own merits and a material deviation from the benchmark for any single performance indicator that cannot be explained by events beyond Terasen Gas control is sufficient basis to argue service quality deterioration.

- Any party may argue that the benchmarks or service quality indicators need to be modified. Any proposed changes to SQIs or benchmarks must be approved by the Commission.

Compliance with the Negotiated Settlement

<u>Principle:</u>

Terasen Gas compliance with regulatory requirements and conduct as a regulated utility will be reviewed at each Annual Review.

<u>Process:</u>

At each Annual Review, Terasen Gas will provide the report required by and filed with the Commission summarizing the results of the annual compliance review of the Code of Conduct and Transfer Pricing Policy of the Commission conducted by Terasen Gas Internal Audit Services.

For each year during the Term of the Settlement, the Commission will provide Stakeholders with the proposed Commission directions to Terasen Gas Internal Audit Services. Any Stakeholder may request the Commission to add directions to review and report on other areas of concern. To assist the Commission in deciding on the merits of such a request relative to the additional cost and effort, the interested party must explain the reasons in support of the additional audit inquiry.

In addition, before the first Annual Review, Terasen Gas independent external auditor will review the work performed by Terasen Gas Internal Audit Services and at the first Annual Review, consistent with Section 8600 of the CICA Handbook Review of Compliance with Agreements and Regulations , will provide a report of Terasen Gas compliance with the Code of Conduct and Transfer Pricing Policy. Subsequent to the first Annual Review, Stakeholders and Terasen Gas may make submissions to the Commission regarding whether or not such a review and report by the independent external auditor of Terasen Gas should be continued for other Annual Reviews.

Any Stakeholder or the Commission Staff may raise for discussion at the Annual Review any action by Terasen Gas that contributed to service quality deterioration or the occurrence of an event that materially affected Terasen Gas operations, costs or services in a manner not anticipated or disclosed during the process leading to the Settlement. In the event that any such issue is not resolved in the Annual Review, participants involved in the Annual Review will have the right to ask the Commission to do one or more of the following:

a) limit the payments that Terasen Gas might otherwise earn from the financial incentive in the Settlement;

b) request the external auditor of Terasen Gas to conduct a specific enquiry on the matter in issue in the complaint and report back to the Commission; or

c) review the terms of the Settlement to determine if the Settlement should be adjusted or terminated.

Improvements to the Annual Review

Interested parties may make submissions to the Commission on items they wish to have included on the agenda for the Annual Review.

To ensure that the Annual Review continues to meet its objectives under the Settlement, Terasen Gas or any interested party may make submissions to the Commission on revisions or improvements to the Annual Review process.

APPENDIX 3

Terasen Gas Inc.
2004 — 2007 PBR Plan
Capital Expenditures True-up Process and End-of-term Benefit Phase-out

Similar to the 1998 — 2001 PBR Plan the 2004 - 2007 plan includes a process for truing up earnings sharing amounts to actual and a capital-related incentive that carries beyond the end of the PBR Term. The 1998 — 2001 Plan also included a process for adjusting the O&M expenses allowed by the formula in future years for the actual customer counts. The same customer count adjustment process will apply to the O&M formula in the 2004 — 2007 Plan but, in addition, it will also be applied to capital expenditures. The allowed capital expenditures will not be rebased to actual during the term but will be adjusted for projected and actual customers as these become known. Also, the accumulated capital benefit at the end of the term will be phased out by factors of 2/3 in the first year after plan expiry and 1/3 in the second year after.

The capital target adjustments and true-up arising from customer count variances will be carried into the subsequent years formula rate base during the PBR term but the forecast rate base for earnings sharing in each year will remain at the original target level. Customer additions variances have only a minor effect on revenue requirement within the first year. The first year additional costs and partial year of revenues from the customer variances are close to offsetting one another. The Company responded to a question on this issue in the November 1999 Annual Review of the previous PBR.

Two tables are attached which provide an example of the treatment of capital in the 2004 - 2007 PBR Plan. The first illustrates the adjustment and true up processes for customer count related variances. The second provides a simplified example (using data from the first table) of the capital benefits end of term phase-out.

Table 1: Capital Expenditures Adjustment / True-up Process

Each year will have forecast, projected and actual target base capital expenditures which result from the different number of customer additions and average number of customers.

The initial 2004 forecast will be set in the November 2003 Annual Review based on forecast number of customer additions, forecast average number of customers, forecast CPI (BC), and 50% of forecast CPI adjustment factor. Subsequently, the 2004 target expenditures will be adjusted in the following year s November 2004 Annual Review for the projected customer additions and projected average number of customers. Then once the year is complete the trued-up 2004 target base capital expenditures will be calculated based on the year s actual customer additions and average number of customers.

Assumed amounts for the actual spending in the customer additions-related and all other base capital categories are also shown in Table 1 (Lines 14 and 26). This is to illustrate how the amount of capital for phase-out at the end of the term will be determined. (Projected actual capital spending is included for 2007 in Column 13, Lines 14 and 26 since the capital benefit amount for phase-out will initially be set before the 2007 actual results are known. The capital benefit for phase out will be trued up for the actual 2007 results in the second year after the term.)

Example: November 2005 Annual Review for 2006 Revenue Requirements

At the November 2005 Annual Review the forecast for the 2006 base capital expenditures will be made using the latest 2006 forecast number of customer additions, forecast average number of customers, forecast CPI (BC), and the 66% of forecast CPI adjustment factor. Also, at this time the 2005 formula capital expenditures for rate base will be adjusted based on the projected 2005 customer additions and projected average number of customers. As well, at this time the trued-up 2004 formula base capital expenditures based on the actual 2004 customer additions and average number of customers will be known. For the calculation of the 2006 rates the 2006 rate base will therefore include the trued-up 2004 formula capital expenditures, the projected 2005 formula capital expenditures, and the forecast 2006 formula capital expenditures.

Table 2: Capital Expenditure Variances for Phase-out after the Term

In Table 2 the phase-out of capital benefits at the end of the PBR term is illustrated. The variances eligible for the phase-out are carried forward from Table 1. The phase-out is calculated using the 14% benefit factor. During the term of the settlement the benefits of the capital savings are shared 50/50 (through the earnings sharing mechanism) between customers and the Company. After the term customers retain their 50% share of the benefit of capital savings and additionally receive one third of the Company s 50% share in the first year after, 2/3 in the second year after and the full benefit in the third year after. The Company retains 2/3 of its 50% share in the first year after expiry of the plan and 1/3 of its 50% share in the next.

TERASEN GAS INC. ATTACHMENT :

2004 -2007 PBR PLAN TABLE

TABLE 1: BASE CAPITAL EXPENDITURES

CAPITAL FORECAST ADJUSTMENT AND TRUE-UP PROCESS

Line		Decision	2004			2005			2006			2007		
No.	Particulars	2003	Forecast	Projected	Actual	Forecast	Projected	Actual	Forecast	Projected	Actual	Forecast	Projected	Actual
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1	Forecast CPI (BC)		1.80%			2.00%			2.00%			2.00%		
2	Adjustment Factor		0.90%			1.00%			1.32%			1.32%		
3														
4	CPI - AF Factor		100.90%			101.00%			100.68%			100.68%		
5														
6	**CUSTOMER ADDITION DRIVEN CAPITAL EXPENDITURES**													
7														
8	Customer Addition Driven Capital Expenditure Per Customer Addition	$2,093.04	$2,111.88	$2,11188	$2,111.88	$2,133.00	$2,133.00	$2,13300	$2,147.50	$2,147.50	$2,147.50	$2,162.10	$2,162.10	$2,162.10
9														
10	Number of Customer Additions	9,265	8,459	9,500	10,000	8,521	8,300	8,000	8,793	8,800	9,000	8,864	9,000	9,100
11														
12	**Target Customer Addition Driven Expenditure ($000)**	**$19,392**	**$17,864**	**$20,063**	**$21,119**	**$18,175**	**$17,704**	**$17,064**	**$ 18,883**	**$18,898**	**$19,328**	**$ 19,165**	**$19,459**	**$19,675**
13														
14	**Actual Customer Addition Driven Capital Expenditures ($000)**				**$20,000**			**$17,500**			**$17,500**		**$17,500**	**$17,000**
15														
16	**Customer Addition Driven Capital Expenditures Variance - (Savings) / Deficit ($00)**				**($1,119)**			**$436**			**($1,828)**		**($1,959)**	**($2,675)**
17														
18	**OTHER BASE CAPITAL EXPENDITURES**													
19														
20	Other Base Capital Expenditure Per Customer	$85.69	$86.46	$86.46	$86.46	$87.32	$87.32	$87.32	$87.91	$87.91	$87.91	$88.51	$88.51	$88.51
21														
22	Average Number of Customers	775,492	783,070	783,591	783,841	793,433	793,322	793,172	801,569	801,572	801,672	810,604	810,672	810,722
23														
24	**Target Other Base Capital Expenditures ($000)**	**$66,454**	**$67,704**	**$67,749**	**$67,771**	**$69,283**	**$69,273**	**$69,260**	**$70,466**	**$70,466**	**$70,475**	**$71,747**	**$71,753**	**$71,757**
25														
26	**Actual Other Base Capital Expenditures ($000)**				**$66,500**			**$68,000**			**$68,000**		**$67,000**	**$69,000**
27														
28	**Other Base Capital Expenditures Variance - (Savings) / Deficit ($000)**				**($1,271)**			**($1,260)**			**($2,475)**		**($4,753)**	**($2,757)**
29														
30														
31	**SUMMARY CAPITAL EXPENDITURES ($000)**													
32														
33	Target Customer Addition Driven Capital Expenditure		$17,864	$20,063	$21,119	$18,175	$17,704	$17,064	$18,883	$18,898	$19,328	$19,165	$19,459	$19,675
34	Target Other Base Capital Expenditures		67,704	67,749	67,771	69,283	69,273	69,260	70,466	70,466	70,475	71,747	71,753	71,757
35														
36	**Total Target Base Capital Expenditures**		**$85,568**	**$87,812**	**$88,890**	**$87,458**	**$86,977**	**$86,324**	**$89,349**	**$89,364**	**$89,803**	**$90,912**	**$91,212**	**$91,432**
37														
38	**Total Actual Base Capital Expenditures**				**86,500**			**85,500**			**85,500**		**84,500**	**86,000**
39														
40	**Total Capital Expenditures Variance - (Savings) / Deficit**				**($2,390)**			**($824)**			**($4,303)**		**($6,712)**	**($5,432)**
41														
42	**CUMULATIVE CAPITAL EXPENDITURES VARIANCE FOR PHASE-OUT**				**($2,390)**			**($3,214)**			**($7,517)**			**($12,949)**

TERASEN GAS INC. ATTACHMENT 3
2004 - 2007 PBR PLAN TABLE 2
TABLE 2: END-OF-TERM CAPITAL INCENTIVE MECHANSIM
ILLUSTRATIVE EXAMPLE
$000

Line No.	Particulars	2004	2005	2006	2007	2008	2009	2010
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	a). Formula Base Capital Expenditure Spending							
2	Customer Addition Driven Capital Expenditures	$21,119	$17,064	$19,328	$19,675			
3	Other Base Capital Expenditures	67,771	69,260	70,475	71,757			
4	Total Base Capital Expenditures - Final Target per formula	$88,890	$86,324	$89,803	$91,432			
5								
6	b). Actual Base Capital Expenditures							
7	Customer Addition Driven Capital Expenditures	$20,000	$17,500	$17,500	$17,000			
8	Other Regular Capital Expenditures	66,500	68,000	68,000	69,000			
9	Total Base Capital Expenditures - Actual	$86,500	$85,500	$85,500	$86,000			
10								
11	c). Capital Expenditures Variance for Phase-out							
12	Customer Addition Driven Capital Expenditures	($1,119)	$436	($1,828)	($2,675)			
13	Other Regular Capital Expenditures	(1,271)	(1,260)	(2,475)	(2,757)			
14	Total Base Capital Expenditures Variance for Phase-out	($2,390)	($824)	($4,303)	($5,432)			
15								
16	d). Cumulative Capital Expenditures Variance for Phase-out	($2,390)	($3,214)	($7,517)	($12,949)			
17								
18	e). Capital benefit @ 14%	($335)	($450)	($1,052)	($1,813)			
19								
20	Customer portion (50/50 during term, Total benefit less phase-out after)	($167.5)	($225.0)	($526.0)	($906.5)	($1,208.7)	($1,510.8)	($1,813.0)
21								
22	Company portion (50/50 during term, 2/3 & 1/3 Phase-out after)	($167.5)	($225.0)	($526.0)	($906.5)	($604.3)	($302.2)	$0.0

APPENDIX 4

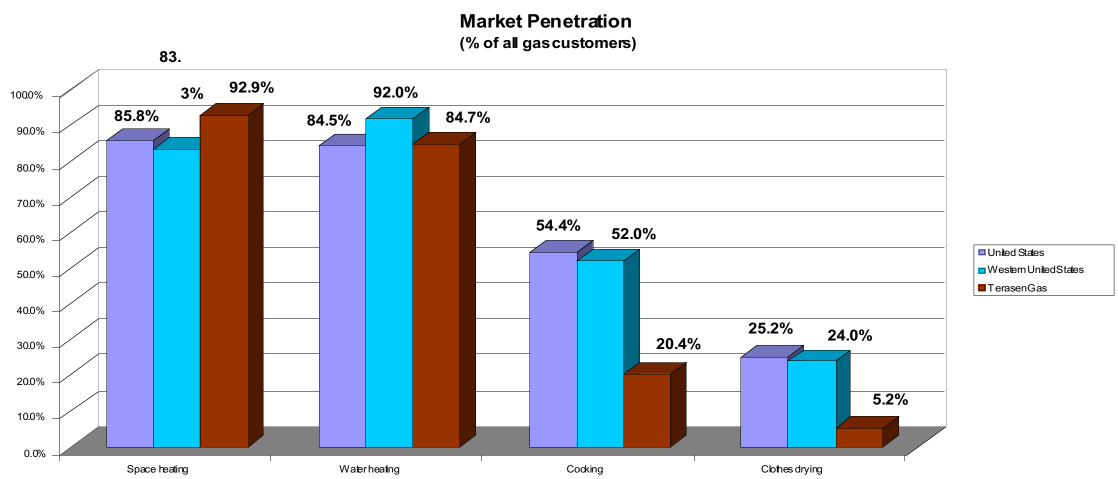
Terasen Gas Inc.
2004 — 2007 PBR Plan
Load Building Mechanism

Description of Proposal

A mechanism during the period of the PBR agreement for Terasen Gas to implement load building programs for residential and commercial customers. (i.e. primarily Rates 1 and 2 customers).

Areas of Opportunity

Examples include but are not limited to increasing the market penetration of appliances in residential households that currently use natural gas and encouraging new customers to add additional appliances. Gas appliances with potential for increased market penetration include, ranges, dryers and to a lesser extent water heaters [1].



How Does This Benefit Customers?

Increased load generates higher use per account and distribution margin.

The Proposed Load Building Mechanism

1. Using coupons, track the number of gas appliances added through a load building program each year of the program.
2. Calculate total annual load added by multiplying the average annual use rate for each appliance by the number of gas appliances added for the year.
3. Under the current RSAM mechanism, any incremental distribution margins associated with added appliance load is returned to customers through the RSAM deferral account, as the actual annual use rate would be higher, all other things being equal, than that of the use rate for RSAM determination due to the added load . Subsequent year use rate adjustments build this savings into rates prospectively.

---

[1] Stats for United States based on AGA survey Patterns in Residential Natural Gas Consumption Since 1980 dated Feb 11, 2000.

4. Terasen Gas proposes instead to transfer the new load related distribution margin from the RSAM deferral account to a separate revenue account for load building initiatives. The revenue recorded in this account will be included in the determination of Earning Sharing proposed under the PBR agreement (i.e. 50/50).
5. Incremental O&M expenditures incurred to support the load building programs will similarly be subject to Sharing.
6. For subsequent years of the PBR agreement, a new Load Building deferral account will be established and the new load revenues will be debited to this deferral account and credited to the new revenue account. Customer use rates for RSAM purposes will be adjusted upwards at the annual review to account for the new load, which will have the effect of increasing use per account (and thereby reducing customers rates), and the Load Building deferral account will be amortized over all customer classes ensuring non-cross subsidization. The revenues recorded in the load building revenue account are shared through the Earnings Sharing mechanism.
7. The Company proposes that customers and Terasen Gas will share equally in the benefit of load added during each year and for four subsequent years (ie. the Load Building Incentive would survive the PBR term). Thereafter, for the balance of the life of the added appliances, the full benefit of the incremental load will be fully taken into account in the use rate for RSAM determination.

APPENDIX 5

Terasen Gas Inc.

2004 — 2007 PBR Plan
Property Taxes and Incentive Proposal

Property taxes are a complex area affected by multiple levels of government (municipal, provincial, First Nations) and several different pieces of legislation (Local Government Act, Vancouver Charter, Local Services Act, BC Assessment Authority Act, Indian Act and others).

For most classes of utility property, the main factors which determine the amount of property taxes are the assessed values and the mill rates.

Within municipalities most distribution-related plant assets (mainly distribution mains and service lines) are exempt from general municipal taxes. Instead the Company pays to each municipality a tax of 1% of the revenues collected from customers within that municipality. The rate for the Vancouver is higher at 1.25 %. This tax is commonly referred to as the 1% in Lieu tax.

For 2004 the forecast for the 1% in Lieu tax is $12,745,000 and the forecast for all other property taxes is $26,170,000

<u>Property Tax Incentive Proposal</u>

Based on intervenor suggestions that a positive property tax incentive would be in customers interests, the Company has developed the following proposal:

For purposes of the incentive:
- Property taxes will be divided between the 1% in Lieu and all other categories (i.e., those which are based on assessed values and mill rates)

- For the 1% in Lieu taxes the incentive will be 10% of the savings related to achieving a reduced rate for the tax or a changed structure to the tax which lowers the amount payable, e.g.
    - If the In Lieu rate was reduced to 0.75% instead 1% (or for Vancouver from 1.25% to 1%), or
    - The In Lieu tax was based on delivery margin rather than the full rate including gas costs at a rate that reduces the total amount of In Lieu taxes payable to more historic levels.

- For the balance of property taxes (General, School, First Nations and other) a modified version of the formula-based approach applicable to O&M expenses and net gas plant in service will be applied.
    - The prior year actual amount will form the base to which the customer growth, inflation and inflation offset factors will be applied to determine the target for the year.

- The Company will be entitled to keep 10% of the amount by which its actual taxes are lower than the target.
  For illustrative purposes assume 2004 forecast is equal to 2004 actual. The 2005 target cost would be:

  $26,170,000 x (1 + customer growth) x (1 + CPI (BC) - 50% of CPI (BC))
  $26,170,000 x (1.0109) x (1 + 2% - 1%) = $26,720,000

  If 2005 actual property taxes were $26,400,000 the Company would retain 10% of the $320,000 difference or $32,000.

- In each case the Company shall be entitled to receive the 10% incentive payment in each year during the PBR term where the specific savings achieved continues.

- If property taxes for the year increase beyond target levels (or rates for the 1% in Lieu), there will be no penalty. The target for the following year will use this higher actual level as the base to which the growth, inflation and offset factors will be applied.

COUNT 21 1-Terasen Gas Inc.-Performance-Based Rate Plan 2004-2008-Registered Intervenor

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TGI-04/08PBR-Lower Mainland Large Gas Users Assocation; Heating Ventilating Cooling Industry Assoc. of BC; BC Greenhouse Growers Association; United Flower Growers Association; Avista Energy

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July 17, 2003

British Columbia Utilities Commission
Box 250
Sixth Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

VIA EMAIL

Attention: William J. Grant, Executive Director

Re: Terasen Gas Inc.
Negotiated Settlement
2004-2007 PBR Plan

Further to our letter of July 4, 2003, R.T. O Callaghan & Associates Inc., on behalf of BC Health Services, accepts the Terasen Gas negotiated settlement package sent with your covering letter dated July 11, 2003.

Sincerely,

R.T. O Callaghan

Pacific Western Energy Inc.
SERVING INDUSTRY & GOVERNMENT SINCE 1992

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V6M 3P2

T. 604-264-9147
F. 604-261-1964

July 11, 2003

Mr. W. J. Grant
Executive Director
British Columbia Utilities Commission
900 Howe St
Vancouver ,BC V6Z 2N3

Dear Mr. Grant

Re: Terasen Gas Inc. – Negotiated Settlement
2004-2007 PBR

Further to your letter of July 8, 2003, the Elk Valley Coal Corp., ("Elk Valley"), Canada's largest producer of metallurgical coal and the world's second largest producer of metallurgical coal for export, participated in the negotiated settlement process, the results of which are attached to your letter of July 8, 2003.

As you appreciate, the negotiated settlement is the end result of an arduous negotiation process,with" give and take "from all participants, which commenced with the Application by Terasen Gas dated April 17, extended over several months, culminating in the aforementioned settlement document.

Elk Valley accepts this Agreement and its components as presented.

Yours truly,

J. David Newlands

cc: Don Shyluk, Vice President, Projects and Development.

The
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Public Interest
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(articled student)
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Routing

July 11, 2003

William J. Grant
BC UTILITIES COMMISSION
6th Floor - 900 Howe Street
Vancouver, BC V6Z 2V3

Dear Mr. Grant:

Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.) Negotiated Settlement 2004-2007 PBR Plan

Further to your letter of July 8, 2003, we confirm the acceptance of BCOAPO *et al.* to the Negotiated Settlement Agreement and Annual Review document on the Terasen Gas Inc. 2004-2007 Performance Based Rate Plan.

Yours sincerely,

BC PUBLIC INTEREST ADVOCACY CENTRE

for Richard J. Gathercole
Executive Director

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Our File:	99-5939
Date:	July 11, 2003

BY E-MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Rob Pellatt

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. - Negotiated Settlement 2004-2007 PBR Plan
- BCUC Order G-29-03

Further to the Commission's letter dated 8 July 2003, I am writing on behalf of Weyerhaeuser Company Ltd., Teck Cominco Metals Ltd., Celgar Pulp Company and Canadian Forest Products Ltd. (collectively referred to as the "Inland Industrials") to confirm that the Inland Industrials accept the proposed Settlement that was attached to the Commission's letter.

The Inland Industrials thank the Commission staff, Terasen and the other customer representatives for their efforts during these negotiations.

Yours truly,

Bull, Housser & Tupper

(original signed by)

David Bursey

dwb/1128072

Terasen Gas

Scott A. Thomson
Vice President,
Finance & Regulatory Affairs

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July 11, 2003

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. W.J. Grant
Executive Director

Dear Sir:

**Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.)
2004 – 2007 Performance Based Rate Plan
Negotiated Settlement Agreement**

Terasen Gas Inc. ("Terasen") has reviewed the revised Negotiated Settlement Documents including appendices, circulated on July 9, 2003, arising from the Negotiated Settlement Proceeding (the "NSP") which commenced on June 9, 2003 for three consecutive days and thereafter held intermittently until June 23, 2003 at the Commission office in Vancouver, B.C.

Terasen believes that the Settlement Documents are a fair and accurate representation of the settlement discussions. It is important to recognize that the settlement is the culmination of negotiations among parties having many diverse interests. The settlement represents numerous compromises among the parties and an overall balance of interests from which no part can be severed. Subject to these considerations, Terasen accepts the contents of the Settlement Documents, as revised, in their entirety.

Yours very truly,

TERASEN GAS INC.

Original signed by Scott Thomson

Scott Thomson

c. Mr. David Bursey
Mr. Richard O'Callaghan
Mr. Richard Gathercole
Mr. Chris Weafer
Mr. David Newlands

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Our File: 09756-0020

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 800 Howe Street
Vancouver, B.C.
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Attention: Robert J. Pellatt

Dear Sirs/Mesdames:

Re: Terasen Gas Inc. (formerly BC Gas Utility Ltd.) — Negotiated Settlement 2004-2007 PBR Plan

We are counsel to the BC Greenhouse Growers Association, the United Flowers Co-operative Association, the Lower Mainland Large Gas Users Association, the Heating Ventilating Cooling Industry Association of BC (HVCI) and Avista Energy (the Stakeholders). Attached please find the Stakeholders dissent to the above-noted Negotiated Settlement.

A copy of this letter and attached Information Request will be forwarded to the intervenors by e-mail as well as by facsimile and mail to those who did not provide an e-mail address.

Yours truly,
OWEN, BIRD

Christopher P. Weafer

Christopher P. Weafer
CPW/jlb
Encl.
cc: Registered Intervenors
cc: Terasen

**DISSENT ON NEGOTIATED SETTLEMENT
ON BEHALF OF THE
THE LOWER MAINLAND LARGE GAS USERS ASSOCIATION,°
BC GREENHOUSE GROWERS ASSOCIATION,°
THE UNITED FLOWER GROWERS CO-OPERATIVE ASSOCIATION, °
HEATING VENTILATING COOLING INDUSTRY ASSOCIATION OF BC, and°
AVISTA ENERGY CANADA LTD.
(the Stakeholders)**

**IN THE MATTER OF THE UTILITIES COMMISSION ACT, °
R.S.B.C. 1996, CHAPTER 473**

AN APPLICATION BY TERASEN GAS INC. (FORMERLY KNOWN AS BC GAS UTILITY LTD.) FOR APPROVAL OF A MULTI-YEAR PERFORMANCE-BASED RATE PLAN TO SET RATES FOR 2004 - 2008

The Stakeholders, who participated in the above-noted settlement, represent the following industries:

1. Lower Mainland Large Gas Users Association which represents 18 large industrial end users and institutional end users located in the Lower Mainland of British Columbia;

2. Heating Ventilating Cooling Industry Association of BC (HVCI) which represents the residential heating industry operating in the Province of British Columbia;

3. BC Greenhouse Growers Association which represents the British Columbia greenhouse industry;

4. United Flower Growers Co-operative Association which represents the flower growing industry of British Columbia; and

5. Avista Energy Canada Ltd., a gas marketing and energy services company which represents more than 200 commercial and industrial customers resident in the Province of British Columbia.

Each of the above Stakeholders has been an active participant in Terasen Gas Inc. (Terasen) related matters and they represent a broad, comprehensive and diverse set of interests as customers and competitors with Terasen. Notwithstanding the diversity of their operations, the Stakeholders share a strongly held common concern about the regulatory model being used in regard to Terasen.

I. Background

Each of the Stakeholders have a common concern about the value of performance based regulation (PBR). The Stakeholders entered into this negotiation process a strongly held belief that cost of service regulation and annual cost of service reviews have at least as many benefits to customers as does PBR. This Stakeholder group will not be surprised if PBR is ultimately found to not conserve the public interest.

The Stakeholders were particularly concerned with and remain opposed to long term PBR settlements which essentially remove Terasen from the review of the British Columbia Utilities Commission (the Commission) in any substantive sense for long periods of time. While the detail of this opposition in regard to Terasen will be set out later in this document, it is also the position of the Stakeholders that notwithstanding some policy support for PBR reflected in Commission decisions and in some provincial government directions, long term PBR is inconsistent with Policy Action Number 12 in the Province s Energy Plan entitled Any Energy for our Future: A Plan for BC which provided the structure of the Commission, and its mandate in regulating Terasen and other energy distributors, will be strengthened. Simply put, the above-noted Stakeholders fail to see how the Commission is being strengthened by providing long term PBR settlements which remove the Utility from a more indepth review and transparent access to economic issues affecting end users.

The Stakeholders have a serious concern with respect to the manner in which the prior PBR settlements resulted in Terasen returning significant benefits to its shareholders in that the price of the Terasen stock doubled during the last PBR term, during the same time period the utility s appetite for passing on cost increases and risks to customers through flow through and deferral accounts was prevalent. The Stakeholders do not have a problem with the financial success of Terasen in the investment community; however, when one reviews Terasen s relationship with the Stakeholder group represented in this submission, a relationship of mistrust and cynicism has evolved during the past PBR periods.

The Stakeholders understand the issues that Terasen faces responding to the investment market place on an on-going basis with quarterly reporting requirements and a need to maintain a positive profile in the investment market. The fear of the Stakeholders is that upon being granted a long term settlement, the interest to comply with utility regulatory requirements, including Code of Conduct, will significantly reduce and various incentives will conflict utility customer interests with those more designed to respond to the investment market.

This cynical view is based on the past record during the PBR period where various costs flowed through to customers more than offsetting any promised PBR benefit. More importantly, the cynicism is reinforced when one looks at the response of Terasen to the directions of the Commission set out in the Commission s decision of February 4, 2003 on Terasen s revenue requirement. The test of commitment to meet regulatory objectives is best determined by review of the most recent conduct of Terasen.

II. Compliance with February 4, 2003 Decision of the Commission

(a) Transfer Pricing Policy

The seriousness with which Terasen takes its utility regulatory requirements is questioned by the Stakeholders. When one reviews the February 4, 2003 decision of the Commission and the response of Terasen to directions set out in that decision, that scepticism is reinforced. At pages 43 to 45 of the February 4, 2003 decision, the Commission set out its determination with respect to Code of Conduct and Transfer Pricing Policy (TPP) indicating that the evidence adduced in the hearing suggests that Terasen has not treated the TPP with sufficient seriousness and care. During the hearing the Commission could not determine that there was always an appropriate distinction between utility activities and cost, and non-utility activities and cost . In response to Lower Mainland Large Gas Users Association s Information Request No. 1 at Appendix C, in this proceeding Terasen set out its response to dealing with the TPP guidelines.

At slide 5 of Appendix C entitled T PP Explained , Terasen sets out how they have instructed their employees to charge either fully allocated cost or market price (not the higher of the two).

The Commission s decision states at page 41, paragraph 2, that BC Gas was concerned specifically about the requirement in TPP to charge the greater of the market price or the fully allocated cost of services supplied to NRBs .

When one reviews the slides presented by management of Terasen to employees in explaining the TPP, it provides that the pricing rules for utilities is based on: full cost or market price . This is not the Transfer Pricing Policy guidelines in that the pricing is to be the <u>greater</u> of full cost or market price.

The Commission also dealt with the issue of incremental pricing of services which is neither fully allocated cost nor market cost pricing. At the revenue requirement hearing, Commission council cross-examined Terasen on incremental pricing and questioned that if the incremental pricing was zero (as Terasen said the website work was), would there be no charge for the service? Terasen answered in the affirmative.

The incremental price issue is seen in the Grey Area section of the slide show presented in response to the above-noted information request. At slides 11 and 12 entitled My Work it instructs employees as follows: If work seems to relate to both utility and NRB or Inc., consider the context: if NRB did not exist, would Utility still do this work? The question implies that the answer is yes , then incremental cost of zero should be applied to the work. The question which should be asked in order to apply TPP correctly —is fully allocated cost or market price whichever is greater - is the NRB or Inc. receiving value for my work? If the answer is in the affirmative, then the fully allocated or market price, whichever is greater, should be applied.

In conclusion on this point, it is apparent to the Stakeholders that on this issue considered by the Commission in the public hearing, Terasen has not complied with the direction of the Commission and has remained vague and unclear in instructing its employees on this important issue contrary to the direction of the Commission.

(b) Referral of Customers

Further, the information filed in response to Lower Mainland Large Gas Users Information Request No. 1 at Appendix C indicates that Terasen is still referring customers to Terasen NRB s and specific retailers in that the slides indicates that the caller should be directed to two alternative service providers when a referral is made to an NRB. Page 4, Item 6 of the Terasen s Code of Conduct specifically states that BCGUL will not preferentially direct customers seeking competitively offered services to an NRB or a specific retailer . It is significant that Terasen requested this item be removed from the Code of Conduct in their 2003 revenue requirement application, then dropped the request, yet is instructing their employees to preferentially direct customers to NRBs and specific retailers. Again, it is an example of where a matter was dealt with in some detail and with some serious level of concern at the hearing process, directions arise in the decision of the Commission, and Terasen appears to be attempting to avoid compliance with the direction. This is not conduct which supports lessening the regulatory oversight of the utility.

(c) Compliance with Commission Direction on Website

A review of the website also indicates that Terasen has not taken the Commission s decision in February, 2003 seriously. This was a matter raised by HVCI and a matter that caused concern to the Commission is reflected in its decision at pages 44 to 45. A review of the Terasen website indicates that far from reducing confusion, the renaming of BC Gas Utility Ltd. to Terasen Gas and the creation of subsidiaries such as Terasen Utility Services Ltd. has created more confusion in the minds of customers. More importantly, Terasen has not responded to the direction of the Commission which was to create separate and distinct websites for Terasen Gas and Terasen, Inc. and its group of NRBs. Further, the decision indicated that there should be no direct links from the Terasen Gas website to non-regulated business activities of Terasen, Inc. Specific links from Terasen Gas to the Inland Pacific Connector and to IPCO and CIPI are, along with numerous other links, in direct contradiction to the decision of the Commission of February, 2003. If the Commission s decisions are not being fully complied with on these obvious examples, what else is being overlooked?

(d) Separation of Management Function

A further direction of the Commission was the separation out of the management function of BC Gas Inc. and BC Gas Utility Ltd. We are advised by the companies that they will provide a study at the end of August on this topic. With respect to the provisioning of a study, it is not a satisfactory response to an issue that has been in existence for some considerable period of time and the Annual Review in November will need to deal with a more significant proposal by Terasen in order to resolve this significant issue. The fear of Stakeholders is that Terasen will follow the model pursued in Ontario by other utilities in PBR periods which is to maximize return to the non-regulated business side of the company and maximize cost to the utility side. Only time will tell whether these speculations are correct. However, the risk of long term settlement increases the chance of this occurring by minimizing ongoing public scrutiny.

III. The Appropriateness for PBR

The Stakeholders have participated in negotiations around PBR with Terasen for the past eight years. These negotiations have included the filing and withdrawing of PBR applications by Terasen once it appeared that Terasen would not be successful with its filing. In one instance Terasen withdrew an approximately 17% rate increase and accepted a rate freeze and was successfully able to maintain rates at frozen levels in that year.

A common question of Stakeholders is: what incentive is really needed beyond the regulated rate of return approved by the Commission in annual reviews to ensure that management of Terasen does the job it was hired to do? Clearly the incentive compensation of management and executives is such that they should be highly motivated to perform their jobs as they are some the most well paid regulated executives in the Province, if not some of the highest paid executives in the Province. These Stakeholders fail to understand how professional utility managers would not be incented to properly and prudently run Terasen without the need to offer further incentive to shareholders. Clearly, the utility investment environment is far stronger than it was relative to the investment community on a whole as the days of 20% return on technology investments are long gone. The rapid rise of Terasen Inc. s stock price would indicate that the stability offered by utility investment is strong and here to stay. As a result, the need to offer further incentive to attract investment is significantly reduced and we fail to understand the on-going need for incentives generally. Is this an admission of regulatory flaws of an unwillingness to make business decisions that should otherwise be made without incentives?.

IV. The Integrity of the Regulatory Process

The Stakeholders remain concerned that a long term settlement reduces the Commission s and the Stakeholder s ability to maintain institutional history around the operations of Terasen. Given the long term importance of the utility operations in the Province and the need for stability over the long haul horizon, this lack of institutional record is a risk being adopted for approving long term settlements. The Stakeholders believe that a one or two year cost of service regulatory regime is efficient, effective and serves the interests of customers as well. The Stakeholders believe that no longer than three years should be approved for this settlement as sufficient recovery is provided to Terasen and a significant enough planning horizon is created to enable management to prudently and effectively run Terasen.

V. Conclusion

In conclusion, the Stakeholders do not support the negotiated settlement agreement circulated by the Commission on July 3, 2003 and specifically, the adoption of a PBR term which is in excess of four years. The Stakeholders were prepared to agree to a three year term and believe that that is the maximum term which should be available to Terasen. The Commission determined in previous reviews that a three year term was appropriate and we believe this to be the case. The Stakeholders do take some comfort in the adoption of an annual review process as set out in Appendix A to the settlement but are concerned how engaged the Commission can be considering its resources and growing work load. We trust that Terasen and the Commission will take this annual review seriously to ensure that the interests of customers are protected during this PBR period.

As indicated, the above comments are intended to reflect concern which has grown and become commonly held amongst a broad sector of customers and competitors of Terasen during the past PBR period. Commitments have been made in this negotiation process to improve this situation and the Stakeholders look forward to steps being taken to improve the relationship.

The public trust granted to a monopoly utility requires a high standard of conduct in exchange for the guaranteed rate of return enjoyed by a regulated utility.

The Stakeholders are not asking the Commission to deal with this Application through further public process but simply wish to put their concerns on the public record through this dissent.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Christopher P. Weafer

Christopher˚P. Weafer,
Counsel to: Lower Mainland Large Gas Users Association
BC Greenhouse Growers Association
The United Flower Growers Co-Operative Association
Heating Ventilating Cooling Industry Association Of BC˚
Avista Energy Canada Ltd.

Appendix D9-2

BCUC ORDER G-33-07
TGI 2008-2009 MULTI-YEAR PBR EXTENSION

(Provided in electronic format only to conserve paper)

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc.
Application for the Approval of a Two-Year Extension
of the 2004-2007 Multi-Year Performance-Based Rate Plan for 2008-2009

BEFORE: L.F. Kelsey, Commissioner
L.A. Zaozirny, Commissioner March 22, 2007

O R D E R

WHEREAS:

A. Commission Order No. G-51-03 approved for Terasen Gas Inc. ("Terasen Gas", "the Company"), the Settlement Agreement for a 2004-2007 Multi-Year Performance-Based Rate Plan (the "Settlement"); and

B. The terms of the Settlement required Terasen Gas to hold a Mid-Term Assessment Review to provide an expanded annual review and information on its current and future year activities prior to the end of the third year (2006) of the Settlement; and

C. Commission Order No. G-121-06 established the regulatory timetable including a 2006 Annual Review and Mid-Term Assessment Review on November 15, 2006 (the "Workshop"). During the Workshop, the Company discussed the possibility of an application for the extension of the current Settlement; and

D. On January 19, 2007, Terasen Gas filed its Application for the Approval of a Two-Year Extension of the Settlement Agreement for a 2004-2007 Multi-Year Performance-Based Rate Plan Settlement for 2008-2009 (the "Application"); and

E. In its Application, Terasen Gas states that it engaged in stakeholder consultation during December 2006 and January 2007 with representatives from the following stakeholder groups:
- British Columbia Hydro and Power Authority ("BC Hydro");
- Ministry of Energy of Mines & Petroleum Resources ("MEMPR");
- Inland Industrial Group;
- British Columbia Public Interest Advocacy Centre on behalf of the British Columbia Old Age Pensioners' Organization et al. ("BCOAPO");
- Avista Energy Canada Ltd.;
- Elk Valley Coal Corporation;
- BC Health Services;

- Commercial Energy Consumers Association of British Columbia;
- Lower Mainland Large Gas Users Association; and
- IGI Resources Inc., a BP Energy Company ("IGI Resources")

F. Appendix A to the Application sets out the proposed terms of a two-year extension and are the same as those reviewed with stakeholders during consultation. The proposed terms are mostly extensions of the terms in the current Settlement and contain similar formula, mechanisms, methodologies and wording; and

G. The Application includes a stakeholder letter from MEMPR dated December 21, 2006. MEMPR states that it would support a two-year extension period to the Settlement; and

H. In a letter dated January 22, 2007, BC Hydro stated that it was willing to support a two-year extension of the Settlement with terms as per the Terasen Gas draft term sheets discussed at the stakeholder meeting; and

I. The Commission by Order No. G-8-07 established a written regulatory process for review of the Application; and

J. MEMPR in its Comments of February 5, 2007 support a two-year extension period to the Settlement as indicated in the letter dated December 21, 2006; and

K. On February 9, 2007 BCOAPO filed its Comments. BCOAPO is supportive of an extension of the Settlement Agreement for a 2004-2007 Multi-Year Performance-Based Rate Plan for 2008-2009 and provided a few additional comments including service quality indicators ("SQI's"); and

L. On February 2, 2007 IGI Resources filed its Comments. IGI Resources support a two-year extension of the Settlement with a single qualification. IGI Resources states that the extension of the Settlement should be accompanied by a submission from Terasen Gas stating that during the term of the of the extension the Company will not ask the Commission for reconsideration of its equity thickness or return on equity ("ROE") values; and

M. On February 16, 2007 Terasen Gas filed its Reply Comments. The Company's response to BCOAPO notes that the SQI's would be addressed as part of the next revenue requirements proceeding as suggested by BCOAPO. In response to IGI Resources, Terasen Gas states that it has no current plans to make an application regarding its equity thickness or ROE. Terasen Gas also submits that the qualifications suggested by IGI Resources place an unreasonable restriction on the Company and would be an inappropriate precedent; and

N. On March 1, 2007 the Commission received an application from Fortis Inc. ("Fortis") applying for the approval of the Acquisition of the Issued and Outstanding Shares of Terasen Inc. (the "Acquisition"). In a letter dated March 1, 2007, the Commission offered Intervenors an opportunity to comment on the Application in light of the proposed Acquisition. In the letters of Comment submitted by the MEMPR, BC Hydro and BCOAPO there were no concerns regarding the Acquisition in relation to the Application. The Company, in its Reply Comments dated March 16, 2007, is of the view that the two-year extension of the Settlement is warranted and is in the best interests of the Company and its customers; and

O. The Commission has reviewed the Application, Comments, and Reply Comments received and considers that approval is warranted.

NOW the Commission orders as follows:

1. The Commission approves for Terasen Gas the two-year extension of the Settlement Agreement for a 2004-2007 Multi-Year Performance-Based Rate Plan for 2008 and 2009 as outlined in Appendix A of the Application and also attached as Appendix A to this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 23rd day of March 2007.

BY ORDER

Original signed by

L.F. Kelsey
Commissioner

Attachment

Two-Year TGI Extension

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Term Terasen Gas proposes a five year term for the PBR Plan	A four year term from 2004 to 2007 was accepted.	A two-year period commencing January 1, 2008 and ending in December 31, 2009.
Productivity Page C-25 proposes a results-based adjustment factor of 0.75% each year from 2004-2008 for O&M and Net Gas Plant in Service.	The adjustment factor will be 50% of CPI for 2004 and 2005, and 66% of CPI for 2006 and 2007. See O&M and Capital Additions Forecast sections below.	Continue use of mechanism without change from Current TGI Settlement. The productivity factor of 66% of CPI will be used for both 2008 and 2009, consistent with factor used in 2006 and 2007.
Inflation CPI (BC) will be used to adjust the controllable expenses as described on page C-10. Rates will be set prospectively, and as in the 1998 plan, the rates will not be modified to reflect actual CPI (BC). CPI (BC) is forecast as 1.8% for 2004 and 2% for 2005-2008 in Section H, Tab 3, page 2.2. The Annual Review will update the inflation forecast for the upcoming year as described in Section H, Tab 9, p. 1 and BCUC IR10.1, but there will be no true up to actual CPI(BC). Alternative inflation indices were discussed in BCUC IR 10.2 and Elk Valley Coal Corporation IR#2, Questions 2-4.	CPI (BC) accepted as filed.	Continue use of mechanism without change from Current TGI Settlement.

Terasen Gas

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Customer Growth The Annual Review will update the customer count for the actual number of customers at the start of the year and forecast customer growth for the upcoming year as described in page F1 and BCUC IR 9.1.	Accepted as filed-same as 1998-2001 PBR.	Continue use of methodologies without change from Current TGI Settlement.
Revenues Revenue categories identified on pages C-13 to C-14 include amounts received from sale and delivery of gas, transportation service, revenues received under tariff supplements, $85 from application for service and revenues from account transfers. Revenues will be forecast each year and the company is at risk within the year for variances in industrial revenues, customer additions, applications for service and account transfers. Throughput variances for residential and commercial customers in rates 1, 2 and 3/23 will be subject to RSAM. Variances in Burrard Thermal and SCP revenues will be deferred and amortized. Pages F-1 to F-8 state that the forecast process has a customer additions forecast, an average use per account forecast and an industrial forecast. A 2003 industrial survey will be presented at the 2003 Annual Review. The residential use per account of 108 GJ was used for 2003 and in the Application for 2004. The use per account for rates 1, 2, 3 and 23 will be reforecast at the 2003 and subsequent Annual Reviews. Other revenues of Centra Gas (PCEC) Wheeling Agreement and SCP third party revenues will be forecast each year at the Annual Review. Late payment revenue will be adjusted to the same formula as O&M expenses. Page C-14 indicates that load-building programs will be brought forward either at or before Annual Reviews. These are separate from DSM programs as confirmed in BCUC IR 7.2	Forecast process is acceptable. Earnings variances relating to at risk revenue items will be included in the Earnings Sharing Mechanism.	Continue use of methodologies without change from Current TGI Settlement. At-risk items unchanged. RSAM continues unchanged.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Gas Cost Section H, Tab 8, p. 1 states that the cost of gas used under the PBR will be based on the approved unit gas costs prevailing at the time the volume and revenue forecast is made. Page C-19 proposes the continuation of GCRA and GSMIP.	Accepted as Filed	Continue use of methodologies without change from Current TGI Settlement. Continuation of CCRA and MCRA Accounts (which replaced the GCRA) without change from Current TGI Settlement.
O&M Section H, Tab 9, p. 1 proposes that O&M expense for 2004-2008 be determined by a formula-based approach that starts from a base of the 2003 Decision O&M escalated by growth in customers and inflation less an adjustment factor of 0.75%. The O&M formula on Section H, Tab 9, p. 1 is: [Base Cost x(1+Growth) x (1+Inflation-0.75% adjustment factor)] Page C-13 proposes that pension and insurance costs will be forecast each year with variances deferred for flowthrough amortization over one year. Vehicle and Coastal Facilities Lease are added (not part of O&M formula) Pipeline Integrity Costs-if a planned capital expenditure is to be funded through O&M then page C-19 proposes that the allowed O&M be increased.	Accepted for 2004 – 2007 with adjustment factors of 50% CPI in 2004 and 2005, and 66% CPI in 2006 and 2007. Beginning in 2004, ongoing pipeline integrity costs are to be expensed as O&M and a levelized adjustment will be made to the base O&M in the formula for years 2004-2007. Facilities retrofits will continue to be treated as CPCNs throughout the term. See also Capital Additions Forecast.	Continue use of mechanism/formula without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Overhead Page G-5 proposes a 16% overhead per year from 2004-2008, calculated consistent with the response to BCUC IR 11.1 and Section H Tab 9 Page 2 of the Application.	Accepted as Filed except that the amount of gross O&M not subject to Overheads Capitalized will be escalated by the O&M formula. The amount not subject to overhead capitalization is the sum of $19,373,000 (Section H, Tab 9, Page 2) and the levelized incremental pipeline integrity O&M expenses of $5,505,000.	Continue to use a 16% overheads capitalization rate without change from Current TGI Settlement.
Net Gas Plant in Service Formula Section H, Tab 3, p. 2 proposes that Mid-year NGPiS for 2004-2008 be determined by a formula-based approach that starts from a base of the 2003 Mid-year NGPiS escalated by growth in customers and inflation less an adjustment factor of 0.75%. The NGPiS formula on Section H, Tab 3, p. 2 is: Current Mid-year NGPiS=(Prior Mid-year NGPiS/customer) x (Forecast Average Number of Customers in Current Year) x (1+Inflation-0.75% adjustment factor) 2003 Mid-year NGPiS is based on actual 2003 opening NGPiS and the projected 2003 year end NGPiS from the fall 2003 Annual Review. Formula-based values of NGPiS, accumulated depreciation, CIAOC, net plant additions are not rebased during the five year PBR.	The Net Gas Plant in Service formula approach was not accepted. See Capital Additions Forecast.	The Net Gas Plant in Service Formula was not accepted as part of the Current TGI Settlement.
Capital Additions Forecast Section H, Tab 3, pp. 2.2 to 2.4 and BCUC IR 2.2 show gross plant additions are back-calculated in several steps from the formula-based mid-year NGPiS and forecast retirements. Forecast retirements are the same as the amounts in last year's PBR	<u>Base Capital Expenditures.</u> As per BCUC IR 4.6, use formulas based on customer additions and average number of customers. Using	<u>Base Capital Expenditures</u> Continue use of formula without change from

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
proposal.	(1+CPI (BC)-Adjustment Factor). Base capital expenditure amounts will not be rebased to actual amounts during the term. For rate setting in subsequent years the formula base capital expenditures from the prior years will be adjusted for projected customer counts and trued up for actual customer counts as this information becomes known. The cumulative difference over the four-year term between the trued-up formula based capital expenditures and actual base capital expenditures will be subject to a phase-out of the benefits of 2/3 in the year after the term and 1/3 in the second year after. An example of the capital true-up process and capital benefits end-of-term phase-out is attached as Appendix 3. <u>Capitalized Overhead</u> 16% of gross O&M calculated by formula, consistent with the response to BCUC IR 11.1 and Section H Tab 9 Page 2 of the Application. The levelized O&M increase for ongoing pipeline integrity program expenditures will not be subject to overheads capitalized. <u>CPCN Additions</u> CPCN expenditures are excluded from the capital formula. Except in very unusual circumstances, CPCNs will not be filed for projects below $5 million. Transmission Pipeline Integrity CPCNs will be limited to retrofits, which BCUC IR 23.2.1 (2003 Revenue Requirement Application) showed as $2.8 million in 2004 and $3.0 million in 2005. CPCN expenditures to be included for rate setting purposes will be only for those projects which have been approved by the	Current TGI Settlement. <u>Phase-Out</u> Continuation without change from the Current TGI Settlement. Phase-Out to commence with expiration of settlement extension term. <u>Capitalized Overhead</u> Continue to use a 16% overheads capitalization rate without change from Current TGI Settlement <u>CPCN Additions</u> Continue use of $5 million threshold for CPCN's without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
	Commission and are projected to be in service prior to the year for which rates are being set. The revenue requirement effect of variances between projected and actual CPCN expenditures for those projects being added to rate base will be taken into account in the Earnings Sharing Mechanism.	
15% Plant Additions Benefit Factor Appendix C-A-2. p. 2 proposes that the current year plant additions savings (actual versus NGPiS formula) be multiplied by a factor of 15% to represent the average avoided annual revenue requirement. An example is provided in BCUC IR 1.9.2 showing a levelized saving of 13.21%. The 15% factor provides for the possibility of plant accounts with higher depreciation rates or higher cost of capital in the future.	Accepted for application only to base capital additions for the end-of-term capital benefits phase-out except that the factor should be 14%.	Continuation without change from the Current TGI Settlement. Phase-Out to commence with expiration of settlement extension term.
Depreciation Rates Section H, Tab 4 deals with the calculation of depreciation expense for 2004 to 2008. Depreciation rates for Meters, Meter Installations and Regulators and Computer will be adjusted effective January 1, 2004. Under the PBR proposal, the accumulated depreciation used in setting rates each year in the Annual review process will arise from the NGPiS calculation, as described in BCUC IR 2.1. Retirements to be used in the accumulated depreciation calculation will be forecast each year for the Annual Review.	Accepted as Filed.	Continue to use current depreciation rates without change from Current TGI Settlement.
Restructuring Deferral Account Pages C-15 and C-16 propose that after the PBR Plan is approved, investments in restructuring will be deferred and recovery will commence in 2004 from actual savings before any sharing. If there is a debit balance in the deferral account in 2008 then it is applied against the full term efficiency incentive. In LMLGUA IR 13, the	All restructuring costs incurred during the Term are to be treated as normal expenditures. Specific restructuring initiatives requiring longer term recovery or providing longer term benefits beyond the end of the Term can be brought forward by the Company for	Continue use of deferral account without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Company confirmed that if it incurs restructuring costs and efficiencies do not materialize then the restructuring costs are borne by the Company. In BCUC IR 1.11.5 the Company proposes a non-rate base deferral account. In BCOAPO IR 4.1 the Company proposes that the revenue requirements would not be increased by the amount of the deferral account. In LMLGUA IR 4.1 the Company anticipates that a definition of what is to be included in restructuring costs would be included in the negotiated settlement document. The Company proposed items to be included are in BCUC IR 1.11.1. On page C-15 and in BCUC IR1.11.2 and BCOAPO IR 4.1 and 4.2 the Company states that positive variances from the allowed ROE will first be used to offset the costs included in the restructuring deferral account prior to sharing.	consideration at any Annual Review. Net restructuring costs incurred by the Company between July 1, 2003 and December 31, 2003 will be captured in a deferral account, to be recovered as a 2004 expense. Net restructuring costs refers to the netting off of savings the Company realizes in 2003 from restructuring activities. The deferral account will be non-interest bearing non-rate base.	
Full Term Efficiency Incentive Page C-16 and Appendix C-A-2, pp. 1-4 describe FTEI as motivating new efficiencies and provides for retaining savings for five years after the investment is made to repay the cost of the initial investment before savings are shared with customers.	The FTEI is not accepted. However, there will be a capital benefits phase-out at the end of term as described in the Capital Additions Forecast section above.	The FTEI was not accepted as part of the Current TGI Settlement. The capital benefits phase-out will continue with the phase-out to commence with expiration of the settlement extension term.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Sharing Mechanism Appendix C-A-2, pp. 1-4 describes and provides an example of the sharing mechanism for savings in net O&M, the gross plant additions benefit and industrial revenue variances. The allocation of savings to the Restructuring Deferral Account and the FTEI is also described. Pages C-15 and C-16 propose that sharing commence on January 1, 2004 with 50/50 sharing of earnings above or below the allowed ROE, net of GSMIP, the DSM Achievement Incentive and other incentives. The customers' portion of the sharing will be projected at Annual Reviews and provided to customers by a rider in the following year. The customers' actual portion of sharing shall be determined after year end and variances from projections provided to customers by a rider in the following year. Sustained (two-year average) return that is 200 basis points above or below the allowed ROE triggers an Off-Ramp review.	The 50/50 sharing mechanism is accepted based on the difference between the allowed and actual ROE (net of GSMIP, DSM Incentive, load building and incentives for partially controllable items) using the common equity component of the actual rate base. See Trigger Mechanism.	Continue use of mechanism without change from Current TGI Settlement.
Deferred Charges and Amortization Pages G-6 to G-7 seeks continuation for 2004 to 2008 of: • Deferred interest account to collect interest expense variances from forecast short-term debt rates and from forecast long term debt rates, principle, timing of issues and long term debt issue costs. • DSM incentive grants for deferral of grants of up to $1.5 million per year. BCUC IR 7.2 explained that the deferral account would only be used to collect incentive payments and rebates to customers. Costs associated with advertising (including awareness programs), program promotion, program design, administration, research and evaluation would be O&M expenses.	Proposed deferral accounts and amortization periods are acceptable. A DSM assessment report should be provided at the Annual Review of proposed programs for the upcoming year and an analysis of existing programs.	Continue use of deferral accounts without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Additional requests: • Amortize over 5 years commencing in 2005, the deferred 3rd party revenues arising from the cancellation of PG&E contract net of any mitigation revenues received. • Deferral of variances in pension expense and insurance expense from forecast. • Deferral of the costs of the PBR Application and amortize over 5 years. Section H, Tab 3, pp. 6.1 to 6.6 requests the following treatment: • Deferred interest is amortized over three years. • Market Rebate Incentive-Water Heater Grants are continued until final year of amortization in 2004. • NGV Conversion Grants with continued additions as approved by Orders G-98-99 and G-7-03 and five year amortization. • 2003 Revenue Requirement with five year amortization. • 2004-2008 Revenue Requirements with accumulation of costs and five year amortization. • DSM program to continue with expenditures of $1.5 million per year for 2004-2008 and three year amortization. • DSM-DRIA to continue with three year amortization. • Property Tax Deferral with continued accumulation of variances between forecast and actual with three year amortization. • GCRA and GCRA Interest with continued recording of interest on GCRA variances from forecast. Amortization in accordance with Orders No. G-124-00, G-134-01 and G19-03.		

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
• RSAM will continue to accumulate differences between forecast and actual use rate of RSAM customers per year from 2004-2008. Any RSAM additions are amortized over three years. Variances between forecast and actual balances will accumulate short-term finance costs. • BC Hydro Services Agreement Costs with continuation of two year amortization by 2003 Decision and Order G-7-03. • Coastal Facilities with continuation of five year amortization by Order C-14-98. With deferral of costs approved by Order C-14-98 and two year amortization by 2003 Decision and Order G-7-03. • ABC-T Project Requirements Phase with two year continued amortization commencing in 2003 by Order G-24-02. • Burner Tip Service with continued one year amortization by 2003 Decision and Order G-7-03. • Earnings Sharing Mechanism as an amortization of the January to February 2003 refund over the remaining March to December 2003 period by 2003 Decision and Order G-7-03. • Salmon Arm Reinforcement with continued amortization by Order G-26-00. Final year of amortization in 2003. • NGV Compression Equipment Recovery with continued 10 year amortization by Order G-143-99. • 2001 Rate Design with continued amortization over three years starting in 2002 by Order G-116-01. • Overheads Change-Income Tax Refund and CIAOC Software Tax Savings/OH Change with continued amortization over five years by 2003 Decision and Order G-7-03. • Other Post Employment Benefits with continued regulatory		

Terasen Gas

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
accounting treatment by Order G-7-03. • Deferred 2000 SCP Cost of Service with amortization over five years by Orders G-135-99 and G-7-03 and 2003 Decision. • SCP Net Mitigation Revenue and SCP West to East Transmission with continued five year amortization by Orders G-124-00, G-123-01, G-7-03 and 2003 Decision. • SCP PG&E Contract Cancellation with forecast lost revenue per Letter L-48-02 and requested amortization over five years commencing in 2005. • CCT Deferral with continuation of five year amortization starting in 2003 by 2003 Decision and Order G-7-03 of deferred credit recorded by Orders G-85-97 and G-48-00. • CCT Assessment with amortization period of three years by 2003 Decision and Order G-7-03.		
Working Capital Section H, Tab 5, p. 1 proposes that Gas in Storage and Transmission Linepack and All Other Working Capital will have a revised forecast at the Annual Review. Cash Working Capital will use lead/lag methodology from the 1992 Decision with changes from the 2003 approved lead or lag days currently in rates brought forward each year as necessary. In BCUC IR 11.2 the Company discusses using a formula to calculate cash working capital based on the mid-year NGPiS.	Accepted as filed.	Continue determinations of working capital without change from Current TGI Settlement.

Terasen Gas

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement (“Current TGI Settlement”)	2008-2009 Extension Period
Finance, Accounting and Tax Issues Pages G-1 to G-6 propose: • New long term debt issues of $850 million for 2004-2008 with an expected rate of 7%. A 2003 long-term debt issue of $150 million for 2003. Debt expense to be reforecast at each Annual Review as described on page C-12. • Short term debt rates of 4% for 2004 and 5% for 2005-2008. Debt expense to be reforecast at each Annual Review. • Any changes in GAAP would be treated as flowthrough items. • A report will be filed on the separation of BC Gas Inc. pensions, salaries and expenses from BCGUL. The Corporate Centre is expected to have 40-45 employees. Forecast O&M is consistent with the 2003 Decision and the amounts charged by the corporate Centre to BCGUL will be consistent with the 2003 Decision.	Accepted, but any changes in regulatory treatment resulting from changes in GAAP will require Commission approval.	Continue without change from Current TGI Settlement. Any changes in regulatory treatment resulting from changes in GAAP will require Commission approval.
Regulatory Accounting Methodologies Page C-19 proposes the continuation of GCRA/RSAM accounts, taxes payable method for income taxes, regulatory treatment for CPCNs from the 1998-2001 PBR Plan, accounting for certain assets and rate stabilization accounts on a net of tax basis, accounting for property, plant and equipment to include overhead and AFUDC. Approved depreciation rates are used. The current accounting treatment of property, plant and equipment retirements will continue.	Accepted as Filed.	Continue without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Taxes Page C-13 proposes a deferral account to record variances in property taxes, income tax rates, LCT rates, and any new government tax expenses, charges and levies. Amortization over three years as a flowthrough item. At the Annual Review a forecast of income tax and LCT rates and other tax expenses for the following year will be provided and customers' rates for that following year will be determined on the basis of that forecast.	Accepted as Filed.	Continue without change from Current TGI Settlement.
Exogenous Factors Exogenous Factors are described on page C-16 as items beyond the Company's control that will be adjusted in rates (flowthrough). These factors include judicial, legislative or administrative changes, orders or directions, catastrophic events, bypass or similar events, major seismic incident, acts of war, terrorism or violence, changes in generally accepted accounting principles, standards and policies, changes in revenue requirements due to Commission directions. In BCUC IR 1.5, the Company lists the flow through items and exogenous factors and discusses the merits of fixing an expense and allowing the item to be "at risk". The Company believes that partially controllable items should be evaluated on an item by item basis and considered in the context of the overall PBR.	Accept the arguments of Terasen Gas and accept same practice as 1998-2001 PBR.	Continue use of mechanism without change from Current TGI Settlement. Exogenous factors that have been approved by the Commission throughout the term of the Current TGI Settlement will continue for the extension period.
Service Quality Indicators Appendix C-A-1, pp. 7-14 discusses benchmarks for proposed SQIs. Appendix C-A-1, p. 5 proposes a benchmark based, where possible, on a three year history at the beginning of the PBR that is	Refer to the SQI section in the Annual Review document (Appendix 2)	Continue use of Service Quality Indicators without change from Current TGI

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
maintained throughout the PBR period. Proposed SQIs — Benchmark Response Time to Site for Emergency Calls — 21.1 minutes % of Responses within 30 Seconds -Emergency — 95% % of Responses within 30 Seconds-Non-Emerg — 75% Trans System Annual Reportable Incidents — 2 Reportable/yr % of Customer Bills Meeting Performance Criteria — Score 5.0 or less Meter Exchange Appointment Activity — 92.2% met Directional Indicators — Three Year Average Number of Third Party Damages — 1,219 Leaks per Kilometre of Distribution Mains — 0.0041 BCUC IR 1.10.7 states whether or not the achievement level for SQIs should be used to qualify the Company for an incentive should be dealt with similar to the 1998-2001 PBR. Page 13 of that PBR stated that SQIs will be reviewed at Annual Reviews and participants can make submissions to the Commission that a deviation from a benchmark is significant enough that it should limit incentive payments to the Utility.		Settlement.
Trigger Mechanism Page C-18 proposes that a full regulatory review is triggered if the two-year average achieved ROE after sharing exceeds or drops below the allowed ROE by 200 basis points or if there is a serious degradation of Service Quality Indicators. LMLGU IR 21 clarified that the two-year average refers to two consecutive years and in IR 32 the Company expressed the belief that "serious degradation" cannot be defined in a manner that would foresee all circumstances.	A Commission review of the PBR Plan can be requested by any party if the achieved ROE after earnings sharing varies from the allowed ROE by 150 basis points in any year of the term.	Continue use of mechanism without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Annual Review The process for the Annual Review and rate setting for the following year is described in BCUC IR14.1 as being similar to the 1998-2001 PBR as adjusted for 2004-2008 PBR Plan formulas, SQIs, plant additions.	Expanded 1998-2001 PBR Annual Review process is acceptable. See attached.	Continue use of Annual Review without change from Current TGI Settlement.
No Surprises	Terasen Gas is to advise all parties of any major changes planned for the Utility and nothing in this settlement provides Terasen Gas with any approval to change its business practices to the detriment of customers. For example, the spin off of significant operations, such as those outsourced to CustomerWorks would require disclosure prior to undertaking.	Continue adherence to "No Surprises" clause/spirit without change from Current TGI Settlement.
Mid-Term Assessment Review Page C-18 proposes that a review be held prior to the end of the third year (2006). If there are unintended outcomes or deterioration in service quality, the parties can jointly address a cure. LMLGUA IR 12.1 describes the Mid-Term Assessment Review as an expanded Annual Review.	The proposal is acceptable.	The Mid-Term Assessment review was held in the third year of the Current TGI Settlement (2006). Not necessary for extension term.
Customer Advisory Council (CAC) (This item was not addressed in the Application)	A customer advisory council will be established which meets twice yearly to deal with any customer issues that have arisen during the year. The purpose of the CAC will be to provide a non-binding forum for customer groups and the Company to communicate and deal with customers' concerns constructively and proactively. One of the meetings will be held in	Continue the Customer Advisory Council without change from Current TGI Settlement.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
	advance of the Annual Review to provide an opportunity for customers to raise issues again at the Annual Review which have not been satisfactorily resolved in the CAC process. The Company's representatives on the CAC will comprise of the President, Vice President of Marketing and Vice President of Regulatory Affairs. A record of the meetings will be kept and made available upon request.	
Equity Thickness Page G-1 confirms that the Company finances its assets with a mix of debt and equity following the Commission's approved capital structure of 33% common equity and 67% debt.	The equity component is consistent with the 2003 Decision and is acceptable. This does not preclude the Company from making an application to the Commission for a variation of its equity thickness if appropriate.	Continue with same terms as in Current TGI Settlement, i.e. the terms of this settlement extension "does not preclude the Company from making an application to the Commission for a variation in its equity thickness if appropriate." Also consistent with Current TGI Settlement the terms of this settlement extension does not preclude the Company from making an application to the Commission for a variation in the generic ROE mechanism and the Company's allowed ROE.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Load Building Company proposed incentives around load building initiatives.	Concept of incentives for load building initiatives accepted, subject to DSM-like assessment (including net present value of expected revenues and costs) of each initiative.	Company may develop load building initiatives during the Term consistent with the Current TGI Settlement.
Company proposed framework of specific load building program based on increased penetration for gas cooking, clothes drying and water heating appliances. See attachment. Company may develop other initiatives during the Term.	A DSM-like assessment (including net present value of expected revenues and costs) should be provided at or before Annual Review before initiative starts.	
Other Items		
Partially Controllables Stakeholders expressed interest in exploring positive incentives around partially controllable expenses. The Company was also interested.	Company to have a positive incentive around provincial and municipal government taxes, fees and expenses. Details of an incentive respecting property taxes were agreed. See Appendix 5. Company or interested parties (intervenors/Commission staff) to bring forward any new ideas around positive incentives for partially controllable expenses to Annual Reviews.	Continue without change the property tax incentive as set out in the Current TGI Settlement. Consistent with the terms of the Current TGI Settlement, Company or interested parties (intervenors/Commission staff) to bring forward any new ideas around positive incentives for partially controllable expenses to Annual Reviews.

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
Additional Items for Extension Period		
Comprehensive review of customer connection policies and system extension policies		TGI committed, as part of its 2006 Annual Review and Mid-Term Assessment review, to undertake in 2007 a comprehensive review of its customer connection policies and system extension policies, including its MX test. An application will be made to the Commission for review and approval in 2007 taking into consideration the 2007 Energy Plan and the results of the 2007 BC Hydro Rate Design proceeding, with implementation in 2008.
Review of DSM funding and economic tests		TGI committed, as part of its 2006 Annual Review and Mid-Term Assessment Review, to undertake in 2007 a review of the economic tests used to evaluate its DSM and efficiency related programs. This review will also assess

Settlement Items	2004-2007 PBR Negotiated Settlement Agreement ("Current TGI Settlement")	2008-2009 Extension Period
		the 2006 CPR study and the potential need for increased DSM funding and will take into consideration the anticipated Provincial 2007 Energy Plan. An application will be made to the Commission for review and approval in 2007, with implementation in 2008.

Appendix D9-3

AUC PBR DECISION 2012

Decision 2012-237

Alberta Utilities Commission

Rate Regulation Initiative

Distribution Performance-Based Regulation

September 12, 2012

The Alberta Utilities Commission
Decision 2012-237: Rate Regulation Initiative
Distribution Performance-Based Regulation
Application No. 1606029
Proceeding ID No. 566

September 12, 2012

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1 Introduction and background

1. On February 26, 2010, the Alberta Utilities Commission (AUC or Commission) began a rate regulation initiative to reform utility rate regulation in Alberta. The first stage of the rate regulation initiative is to implement a form of performance-based regulation (PBR) for electric and natural gas distribution companies in place of the existing cost of service regulatory system, usually referred to as rate base rate-of-return regulation. The second stage of the rate regulation initiative will consist of generic reviews of legal and economic issues related to utility regulation for the purpose of making the regulatory system more consistent among companies, more predictable over time and more efficient.

2. In its February 26, 2010 letter,[1] the Commission indicated that the first stage of the rate regulation initiative would apply only to the electricity and natural gas services of Alberta distribution companies under the Commission's jurisdiction. It would not apply to the electricity and natural gas services of transmission companies or to retail electricity or natural gas sales. However, if a company provided both distribution and transmission services, the company was given the option to apply to include its transmission services in its PBR proposal.

3. The procedural steps for this stage of the rate regulation initiative are set out in Appendix 3 to this decision. The division of the Commission presiding over this proceeding was Mr. Willie Grieve (chair), Mr. Mark Kolesar and Dr. Moin Yahya.

4. This decision sets out the Commission's determinations about the form of performance-based regulation that will be employed beginning in 2013 for Alberta electric and natural gas distribution companies.

1.1 The current regulatory framework

5. The utility companies to which this decision applies (the companies) are three electric distribution companies, ATCO Electric Ltd. (ATCO Electric or AE), FortisAlberta Inc. (Fortis or FAI) and EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) and two gas distribution companies, ATCO Gas and Pipelines Ltd. (ATCO Gas or AG) and AltaGas Utilities Inc. (AltaGas or AUI). The distribution and transmission service rates charged by these companies are currently regulated under a rate base rate-of-return form of cost of service regulation.

6. The Commission also regulates the distribution and transmission rates of ENMAX Power Corporation (ENMAX or EPC). In 2009, the Commission approved a formula-based ratemaking

[1] Exhibit 1.01, AUC letter of February 26, 2010.

or FBR plan (also known as a PBR plan) for ENMAX's distribution and transmission services.[2] Prior to that, ENMAX was also regulated under a rate base rate-of-return framework.

7. Under the current rate base rate-of-return regulatory framework, rates are established through a two-phase process. In the first phase, the total amount of money required by the company to provide its regulated services in a year is determined. This is referred to as the revenue requirement, and it is made up of the total annual operating, maintenance and administrative expenses of the company plus the company's capital-related costs (depreciation, debt, and return on equity). The company's debt and equity are used to finance the company's assets (wires, pipes, etc.), which are referred to as its rate base. The cost of debt is the interest that the company pays on its bonds. The cost of equity is determined by the regulator and is referred to as the approved rate of return on equity (ROE). The return on equity actually earned is sometimes referred to as the utility company's profit since all other expenses and costs (operating, maintenance, administration and debt costs) are recovered without any profit margin built into them.

8. In the second phase of a rate application, monthly, hourly or other rates to be paid by individual customers for use of the distribution system are established by determining how much of the revenue requirement should be recovered from each customer class (residential, commercial, etc.) and on what billing unit basis (monthly charge, per kilowatt hour or gigajoule, etc.). Rates are established by dividing the revenue requirement for each customer class by the billing units.

9. In Alberta, all of these determinations are made on a forecast basis, generally for two years. So, for example, a company could file a rate application for the two years 2011 and 2012. A forecast revenue requirement would be provided by the company for each of the two years, called test years. The Commission is required to test the application for reasonableness and allow only reasonable forecast expenses, including capital-related costs, to be included in the revenue requirement and rates for the two test years. These forecasts are based on the companies' plans and expectations over the two test years. When new rates are implemented for the two years, the company begins to collect them and may or may not carry out the plans it put before the Commission in its forecasts. At the end of the two years, the company may apply for rates for the next two test years.

10. If the company is able to provide service for less than it had forecast during the previous two years, or if billing units (the number of customers, electricity or natural gas use, etc.) are greater than were forecasted, the company is permitted to keep the extra revenue as extra profit in those years. However, the forecast revenue requirement and rates for the next two years are to take into account the actual results from the previous two years. In this way, customers receive the benefit of the company's improved productivity (lower costs and higher billing units) from the previous period in the rates determined for the next two years. If the company then improves its productivity in these next two years, those benefits will again be passed on to customers in the next period, etc. Of course, the actual results for the immediate prior year are not available to assist in assessing the forecasts for the two test years of a new test period. This means that any efficiency gains in the prior year may not be fully incorporated into those forecasts.

[2] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID No. 12, March 25, 2009.

11. While this regulatory model is relatively straightforward in its conception, it produces some incentives and disincentives that are widely recognized.[3] Generally, under cost of service regulation, since the company earns a profit on the equity in its rate base, there is an incentive to choose spending money on capital assets, on which a return can be earned, over spending on maintenance, for example, on which a return is not earned. In addition, there is no incentive to minimize the costs of capital assets. The more that is spent and included in the company's rate base, the more return that can be earned. This means that the regulator must make some sort of after-the-fact assessment of whether the company spent too much money on capital assets and, if so, must disallow recovery of the amount by which actual costs exceeded a prudent amount. In addition, there is little incentive for the company to invest in long term cost reduction initiatives because any cost reductions achieved would be passed on to customers automatically in subsequent rate proceedings. The use of forecasted test years in Alberta was adopted partly in response to these incentives. However, while there are incentives to reduce expenses in the test years so as to beat the forecast and thereby increase profits, this only works for investments in efficiency that can be recovered in a year or two. In addition, this framework also creates an incentive for the companies to provide cost forecasts (both operating and maintenance (O&M), and capital) that are higher than what the company expects to be able to achieve or to provide conservative forecasts of the number customers and other billing units that are lower than what the company expects, thus increasing profits above the approved return.

12. In addition to the issues raised by the basic regulatory model, the framework has been made more complicated by the restructuring of the industries. In both the electricity and natural gas industries, companies that were once vertically integrated monopolies engaged in electricity generation, distribution, transmission and retailing, or in natural gas production, distribution, transportation and retailing, are now structurally separated. The production of electricity and natural gas and the retailing of electricity and natural gas are now open to competition. The costs for the distribution and transmission services must be separated from the costs of production and retailing and separate rate bases established. Issues of cost allocations among different regulated entities or among regulated and unregulated affiliates in the same corporate structure emerge and must be monitored. These issues include allocations of rate base, charges from one division to another, prices charged by affiliates providing services in competitive markets that also provide those services to the regulated affiliate, among others. In the current regulatory framework, each of these issues must be monitored and assessed in every regulatory application, and a number of new regulatory tools have been developed to deal with these costs and allocations both within and outside of the normal rate review process. As a consequence, the industry restructuring has added to the need for rate riders (items on the bill to recover costs that change from time to

[3] See Brown, Carpenter and Pfeifenberger regarding capital expenditure gaming (Exhibit 34.01, slide 3); Dr. Carpenter regarding incentive to bias its rate base allowance upward, (Transcript Volume 7, pages 1194 and 1195); Dr. Cronin that regulated firms are overcapitalized (Exhibit 299.02, page 124); Dr. K. Gordon, ATCO Gas witness in an earlier proceeding regarding over-forecasting, (Exhibit 357.06 citing Application No. 1400690, 2005-2007 Rate Application, Transcript Volume 5, pages 838-846); Ms. Frayer and Dr. Weisman, regarding cost-of-service's significant regulatory burden (Fortis application, Exhibit 100.02, Appendix 2, page 5, lines 20-23 and Exhibit 103.03, Dr. Weisman evidence, page 9, paragraph 20); Dr. Weisman's evidence that cost-of-service regulation "is essentially a cost-plus contract" (Exhibit 103.03 page 23 paragraph 57); Calgary evidence that a "regulated firm may use its information advantage strategically in the regulatory process to increase its profits … to the disadvantage of ratepayers." Exhibit 298.02, page 15, paragraph 34; The United States Department of Justice that "cost-of-service regulation may do little to promote, and may actually inhibit the achievement of, technical, allocative, or dynamic efficiency" as quoted by the UCA in Exhibit 299.02, page 119.

time[4]), flow-through mechanisms and deferral accounts. At last count the Commission was administering approximately 100 deferral accounts, riders and pass-through mechanisms for the distribution and transmission companies under cost of service regulation.

13. One result of the basic regulatory model and the industry restructuring that has been imposed on top of it has been both a tremendous increase in the detailed information filed by the regulated companies and an increase in the number of ongoing proceedings for deferral accounts and related matters. For example, in a recent revenue requirement application filed by EPCOR amounted to approximately 4,200 pages including all schedules and appendices.[5] The process that followed produced another 8,000 pages of information requests and responses as well as additional evidence and written questions and responses. In addition, from that proceeding, one of the issues was spun-off to be considered in a separate proceeding. As another example, there is a 10-year ongoing series of proceedings to benchmark and, through that, to establish a method to review and approve charges to the ATCO utilities by their affiliate ATCO I-Tek Inc.[6] As a further complication, a number of issues have been litigated differently by different companies and decided differently by different board[7] or Commission panels.

1.2 Performance-based regulation

14. In its February 26, 2010 letter, the Commission stated that the rate regulation initiative:

> ... proceeds from the assumption that rate-base rate of return regulation offers few incentives to improve efficiency, and produces incentives for regulated companies to maximize costs and inefficiently allocate resources. In addition, rate-base rate of return regulation is increasingly cumbersome in an environment where some companies offer both regulated and unregulated services and where operations that were formerly integrated have been separated into operating companies, some of which require their own rate and revenue requirement proceedings. These changes in the structure of the industry, occasioned by the introduction of competition in the retail and generation/production segments of the electricity and natural gas industries, have resulted in additional negative economic incentives for companies regulated under rate-base rate of return regulation. These conditions complicate the task for regulators who must critically analyze in detail management judgments and decisions that, in competitive markets and under other forms of regulation, are made in response to market signals and economic incentives. The role of the regulator in this environment is limited to second guessing. Traditional rate-base rate of return regulation provides few opportunities to create meaningful positive economic incentives which would benefit both the companies and the customers. The Commission is seeking a better way to carry out its mandate so that the legitimate expectations of the regulated utilities and of customers are respected.[8]

4 Examples of rate riders include but are not limited to: ENMAX's Quarterly Transmission Access Charge, FortisAlberta's Quarterly Transmission Access Rider, ATCO Electric's Rider S Quarterly System Access Services Adjustment and EPCOR'S Rider K Transmission Charge Deferral Account True-up Rider.

5 EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, 2010-2011 Transmission Facility Owner Tariff, Application No. 1605759, Proceeding ID No. 437.

6 Decision 2010-102: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2003-2007 Benchmarking and ATCO I-Tek Placeholders True-Up, Application No. 1562012, Proceeding ID No. 32, March 8, 2010; Decision 2011-228: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2008-2009 Evergreen Application, Application No. 1577426, Proceeding ID No. 77, May 26, 2011; ATCO Utilities, 2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009, Application No. 1605338, Proceeding ID No. 240.

7 The Alberta Energy and Utilities Board (board or EUB), is a predecessor to the Alberta Utilities Commission.

8 Exhibit 1.01, AUC letter of February 26, 2010, pages 1-2.

15. In stating its intention to move to a performance-based regulation framework for the distribution companies, the Commission also stated the following objectives for PBR:

> The first is to develop a regulatory framework that creates incentives for the regulated companies to improve their efficiency while ensuring that the gains from those improved efficiencies are shared with customers. The second purpose is to improve the efficiency of the regulatory framework and allow the Commission to focus more of its attention on both prices and quality of service important to customers.[9]

16. A basic PBR plan begins with rates established through a cost of service proceeding such as a rate base rate-of-return proceeding. Those rates are then adjusted in subsequent years by a rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the companies can be expected to achieve during the PBR plan period. Thus, adjusting rates by I-X, rather than in cost of service proceedings, breaks the link between a utility's own costs and its revenues during the PBR term. In much the same way as prices in competitive industries are established in a competitive market, prices adjusted by I-X reflect industry-wide conditions that would produce industry price changes in a competitive market. Each company's actual performance under PBR will depend on how its own performance compares to the industry's inflation and productivity measures.

17. Establishing prices in this way during the term of a PBR plan creates stronger incentives for the companies to improve their efficiency through cost reductions and other actions because they are able to retain the increased profits generated by those cost reductions longer than they would under cost of service regulation, especially with rates under cost of service regulation that are re-set every two years. At the same time, under a PBR regulatory framework, customers automatically share in the expected efficiency gains because they are built into rates through the X factor regardless of the actual performance of the companies. In addition, the X factor in a PBR plan is often increased by a stretch factor so as to capture efficiency gains that should be immediately realizable as the regulatory system changes from cost of service to PBR.

18. But an I-X mechanism alone is not sufficient. In competitive markets, other factors that affect only the industry in question, such as an increase in taxes, would be passed through to customers by that industry in its competitive prices. PBR plans typically include a Z factor to deal with such significant events outside the companies' control that are specific to the industry and would not be reflected through the inflation factor (I). The Z factor can also be used to increase or decrease the companies' prices to reflect cost changes caused by unique company-specific events (such as floods or ice storms) outside the company's control and that are not reflected in the inflation factor.

19. In some cases, these types of costs may be predictable, although the amounts of these costs may not be. In those cases, other mechanisms may be established to allow for automatic adjustments to rates to pass those costs through to customers. For example, in the ENMAX FBR plan established in Decision 2009-035, the Commission made provision for the flow-through of transmission system charges imposed on the distribution company by the Alberta Electric System Operator (AESO).[10] Other similar types of charges beyond the control of the companies

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[9] Exhibit 1.01, AUC letter of February 26, 2010, page 1.

[10] Decision 2009-035, pages 52-53. For further discussion on the AESO's role see Section 7.4.2.1.1.

may also be included in a PBR plan as a Y factor to be passed through to customers. The companies' proposals in this proceeding included a number of these types of factors.

20. In the ENMAX FBR plan,[11] the Commission also established a G factor to deal with capital additions to ENMAX's transmission system. In this proceeding, each of the companies proposed specific provisions for some types of capital investments to be handled outside the I-X mechanism. In this decision those types of capital adjustments are referred to as K factors.

21. All of these types of cost-based adjustments (whether Z, Y or K) are carefully defined and limited in their scope because they are inconsistent with the objectives of PBR in that they have the effect of lessening the efficiency incentives that are central to a PBR plan.

22. PBR plans are typically established for a defined term such as five years. At the end of the term, rates are often re-established in a cost of service proceeding, and another PBR term begins based on those rates. Other approaches may also be used at the end of the PBR term, such as simply continuing the plan or making some changes to the parameters and continuing based on existing rates. However, it is likely that a cost of service review will occur eventually.[12] In either case, the values of I and X, for example, and the other parameters of the plan are reviewed and may be changed. The fact that eventually rates will be re-established based on cost of service lessens the efficiency incentives under PBR as the time for the cost of service review approaches. Generally, the longer the PBR term, the greater are the incentives for the company to look for and invest in new productivity-enhancing business practices.

23. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality, regardless of the form of regulation. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures.

24. It is the Commission's expectation that the adoption of a PBR plan will make the regulatory system more efficient over time as the Commission, interveners and companies become more familiar with it. At the same time the Commission expects that, under PBR, customers will experience lower rates than they would have had if the current rate base rate-of-return framework had continued unchanged.

25. During the first PBR term, the Commission will also conduct generic proceedings to deal with a number of utility regulatory issues so that the regulatory framework will be more efficient in the future.[13]

[11] Decision 2009-035, pages 41-48.
[12] Transcript, Volume 1, page 197, lines 11 to 22, Dr. Makholm.
[13] The generic cost of service proceedings is discussed in Section 16.

1.3 Performance-based regulation preparations

26. In its February 26, 2010 letter, the Commission invited interested parties to assist the Commission in determining the scheduling and the scope of issues for PBR implementation. The Commission held a roundtable with 18 interested parties on March 25, 2010 to discuss steps for the implementation of PBR.[14] The companies objected to the Commission's stated preference that PBR begin on July 1, 2011. The companies asked for more time to prepare for PBR and to file rate cases to establish their going-in rates for PBR, a process that would take some time. In addition, during the roundtable, participants agreed that the Commission should conduct a workshop so that the participants could become more familiar with the theory of and experience with PBR. Participants also agreed that the Commission should initiate a short proceeding to establish common principles to guide and assess PBR proposals to be subsequently filed by Alberta distribution companies within the Commission's jurisdiction.

27. In its April 9, 2010 letter[15] the Commission announced that in response to requests by participants, it had engaged the Van Horne Institute to conduct an independent PBR workshop on May 26 to 27, 2010 in order to educate participants about the issues, terminology and concepts raised by PBR. Participants were informed that the information provided and views expressed at the workshop did not necessarily represent the views of the Commission. Ninety-two people representing all of the utility companies and intervener groups attended the workshop.

28. Also, in its letter of April 9, 2010, the Commission initiated a proceeding to solicit comments on the principles that should guide the development of PBR in Alberta. The proceeding commenced on June 10, 2010 with submissions from the various parties and closed on June 24, 2010 with the submission of reply comments.[16] The Commission reviewed these submissions, and in Bulletin 2010-20,[17] dated July 15, 2010, the Commission found that there was general agreement on the following five principles:[18]

> **Principle 1.** A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.
>
> **Principle 2.** A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3.** A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4.** A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5.** Customers and the regulated companies should share the benefits of a PBR plan.

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14 See Attachment 1 of Exhibit 6.01 for a list of participants, page 2.
The following parties suggested clear objectives before instituting PBR: AltaLink, page 1; ATCO, page 1; Calgary, Principle 1, page 3; UCA, page 1; IPCAA, Principle 1, page 1.

15 Exhibit 6.01, AUC letter of April 9, 2010.

16 Appendix 1 of Bulletin 2010-20 lists the parties who made submission and the associated exhibit numbers.

17 Bulletin 2010-20, Regulated Rate Initiative – PBR Principles, July 15, 2010.

18 Exhibit 64.01, Appendix 2 of Bulletin 2010-20 lists references of parties with similar principles in their submissions.

29. The gas and electric distribution companies present at the March 25, 2010 roundtable (other than ENMAX) agreed that they could each file a PBR proposal by the end of the first quarter of 2011. Therefore, in Bulletin 2010-20, the Commission directed these gas and electric distribution companies to file their PBR proposals by March 31, 2011. The distribution companies that are also transmission facility owners could choose whether or not to include their transmission operations in their proposed PBR plans. Parties were required to explain how their PBR proposals were consistent with the Commission's five principles for PBR and how their proposals would satisfy the Commission's objectives for PBR.

30. On September 8, 2010, the Commission notified the parties that it had retained National Economic Research Associates (NERA) to prepare a total factor productivity (TFP) study that could be used as the basis for determining an X factor in a PBR plan for the electricity and natural gas distribution industries.[19] The NERA TFP study was to be filed by December 31, 2010.[20] The filing date for the companies' PBR proposals was later changed to July 26, 2011, in order to allow the companies sufficient time to consider the evidence to be filed by NERA, with the objective being to implement PBR effective January 1, 2013.[21]

1.4 Overview of PBR proposals and the Commission's approach

31. In Bulletin 2010-20[22] that established the PBR principles, the Commission also provided the following guidance to the companies and interveners:

> In the Commission's opinion, a PBR plan consisting only of an I - X formula would, to the greatest extent possible, mimic the efficiency incentives of competitive markets provided that the X factor requires the company to achieve annual productivity improvements at least equivalent to those of the relevant industry. Therefore, the Commission expects each proposal to include I - X as part of the PBR plan. Some parties proposed principles that dealt with certain aspects of various PBR plans such as exogenous adjustments, earnings sharing, the term of the plan, capital adjustments, reporting requirements and rate structure changes, among others. In the Commission's opinion, these are more properly considered as potential elements of a PBR plan and are not principles. In making their proposals, companies may choose to include these or other elements in order to address circumstances resulting from Alberta's market structure, the industries in which the companies operate, unique company-specific circumstances or other circumstances that may be relevant. Companies are expected to fully explain the circumstances that give rise to the need for each element, how each element addresses that need and how each element is justified by the principles and objectives of PBR.[23]

32. The companies filed their PBR proposals on July 26, 2011. Interveners filed their PBR evidence on December 16, 2011.

33. The Commission received a wide range of proposals from the companies and the interveners. Parties agreed with the Commission's objectives and principles and, for the most part, fashioned their PBR proposals to be consistent with them. The Office of the Utilities

[19] Exhibit 71.01, AUC letter – Retention of Consultant to Develop a Basic X Factor.
[20] Exhibit 80.02, NERA first report.
[21] Please see Appendix 3 for details of the procedural steps.
[22] Exhibit 64.01, AUC Bulletin 2010-20.
[23] Exhibit 64.01, Bulletin 2010-20, page 3.

Consumer Advocate (UCA) expressed concerns about moving to PBR at this time.[24] The UCA's position was that the companies are performing well under the current cost of service framework and that more company-specific information is needed to implement the type of PBR plan that the UCA envisions. The Industrial Power Consumers Association of Alberta (IPCAA) recommended a limited adoption of PBR until two types of performance metrics (quality of service and asset condition metrics) are available and the necessary quality and reliability safeguards are implemented.[25] EPCOR proposed a PBR plan that excludes all capital-related costs from the application of an I-X mechanism.[26] The other parties (ATCO Electric,[27] ATCO Gas,[28] Fortis,[29] AltaGas,[30] the Consumers' Coalition of Alberta (CCA)[31] and The City of Calgary (Calgary)[32]) proposed or accepted plans that applied an I-X mechanism to all categories of costs. Each of these parties also argued for or accepted some type of provision to deal with some capital costs outside of the I-X mechanism and proposed or accepted the need for certain new or existing deferral accounts and rate riders.

34. In seeking to develop a PBR mechanism that can best achieve the Commission's objectives while being consistent with all of its principles to the maximum extent possible, the Commission has carefully considered all of the submissions of the companies and interveners. The Commission is employing an I-X mechanism and a five-year term as part of its PBR plan in order to create the same efficiency incentives as those that are present in competitive markets to the greatest extent possible for the electric and gas distribution companies. The inclusion of an efficiency carry-over mechanism will further enhance these incentives. In doing so, the Commission is also making provision for the exclusion of some capital costs from application of the I-X mechanism where necessary in order to accommodate the unique circumstances of each regulated company. The Commission is employing a revenue-per-customer cap for natural gas distribution companies and a price cap for electric distribution companies in order to recognize the differences between those two industries. The Commission is also making provision for the treatment of necessary deferral accounts and flow-through mechanisms for each company as part of its PBR plan.

35. In making its determinations, the Commission has considered the effect of the combination of the I-X mechanism with the treatment of some capital-related costs outside of the I-X mechanism, the Z factor adjustments and the provision for deferral accounts and flow-throughs to protect the companies from significant unforeseen events that are outside their control. In addition, the Commission has considered the statements of a number of witnesses regarding the incentives to over-forecast capital expenditures, the observation of Dr. Lowry that the companies have considerable flexibility in the timing of capital replacements[33] and the views of Dr. Weisman that with the incentives created by the plan, the companies will discover new ways to conduct their businesses.[34] Having considered the statements of the parties and

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24 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 12-13.
25 Exhibit 306.01, IPCAA Vidya Knowledge Systems evidence.
26 Exhibit 103.02, EPCOR application.
27 Exhibit 98.02, ATCO Electric application.
28 Exhibit 99.01, ATCO Gas application.
29 Exhibit 100.01, Fortis application.
30 Exhibit 110.01, AltaGas application.
31 Exhibit 307.01, CCA evidence.
32 Exhibit 298.02, Calgary evidence.
33 Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 59; Exhibit 636.01, CCA argument, Section 8.1, paragraph 118.
34 Exhibit 103.03, EPCOR application, Appendix A, page 20, paragraph 49.

witnesses, and the full record of the proceeding, the Commission is satisfied that the PBR plans approved in this decision will provide each of the companies with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return over the five-year term of the plan. With regard to earning a fair rate of return, there was general agreement[35] among the experts and the parties that the opportunity to earn a fair rate of return should be considered over the term of the PBR plan and not on a year-by-year basis.

36. Customers will share the benefits from the improved efficiency incentives under PBR through the inclusion of an X factor and a stretch factor in the plan. Customers will be protected against earnings significantly above the approved ROE, and the companies will be protected against earnings significantly below the approved ROE, by the incorporation of a re-opener in the plan. If the ROE of a company meets the conditions for a plan re-opener to take effect, this will afford an opportunity for the Commission to re-examine the parameters of the plan and, if required, to adjust them.

37. The Commission is also making provision for enhanced quality of service rules and measures to address the incentive that companies might have to reduce their costs in such a way that service quality declines in the short and long term.

38. The Commission has sought to make the PBR plans as easy to understand, implement and administer as possible given the structure of the electric and natural gas industries in Alberta, the need to accommodate the unique circumstances of each company and the recognition that this is the first time PBR has been adopted for all of the distribution companies. The Commission is confident that as the parties become more familiar with PBR and as the companies discover new ways to adapt their businesses to the opportunities PBR offers, it will be possible to further streamline the regulatory framework to achieve the Commission’s objectives.

39. Finally, the Commission is satisfied that the PBR plans meet the objectives for PBR described in its February 26, 2010 letter. Furthermore, the Commission has taken particular note of the five PBR principles articulated in Bulletin 2010-20. The Commission is satisfied that the PBR plans overall, and each of the elements of the plans, are consistent, to the maximum extent possible, with all five principles.

40. The Commission intends to review PBR as it comes to the end of the first term and to consider extending the plans or incorporating other approaches if those can be demonstrated to better balance regulatory efficiency and regulatory effectiveness in a way that achieves the Commission’s objectives and satisfies the Commission’s principles.

2 Approaches to rate regulation

41. The UCA (Office of the Utilities Consumer Advocate), IPCAA (Industrial Power Consumers Association of Alberta), and EPCOR each proposed alternatives to the Commission’s preferred approach to PBR (performance-based regulation) stated in its letter of February 26, 2010 and Bulletin 2010-20. These proposals affected either the time at which PBR could be implemented in Alberta for the electric and gas distribution companies, the nature of PBR, or the

[35] Transcript, Dr. Carpenter, Volume 3, pages 565-566; Transcript, Mr. Camfield, Volume 8, page 1373; Transcript, Mr. Gerke and Dr. Weisman, Volume 10, pages 1828-1829; Transcript, Ms. Frayer, Volume 11, page 2190.

costs to which PBR would apply. In this section, the Commission addresses each of these alternative proposals. The Commission also addresses specific elements of these proposals throughout this decision.

2.1 The UCA's proposal

42. The UCA proposed a delay in the implementation of PBR. The UCA developed its own objectives for PBR and then used those objectives, in combination with its view of what a PBR plan should be like, to justify the delay.

43. The UCA's objectives were expressed as follows:

- Better economic incentives in order to achieve productivity improvements, which will result in lower customer rates than under cost of service regulation,
- Clearly defined performance standards with penalties for failure to achieve specified performance targets, and
- A reduction in the overall regulatory burden by improving the efficiency of the regulatory framework.[36]

44. The UCA stated that if PBR would not meet its three over-arching objectives, then the move to PBR at this time must be reassessed. The UCA also submitted that based on the available information, there is no compelling reason to switch to PBR. Three principal reasons were given for this position:

1) The evidence of Dr. Cronin [expert witness for the UCA] that regulatory burden does not go down under PBR;
2) The large capital forecasts upon which the applicants' PBR plans are based, and, in the case of EDTI the complete exclusion of capital from its PBR plan; and
3) The lack of information presently available about the applicants: (i) comparative performance; (ii) present efficiency levels, and (iii) potential for efficiency improvements.[37]

Commission findings

45. The Commission has considered the UCA's objectives for PBR and its reasons for reassessing the move to PBR at this time. The Commission agrees with the objectives that PBR should provide better economic incentives and result in lower rates than under cost of service regulation. The Commission also agrees that PBR should reduce the regulatory burden by improving the efficiency of the regulatory framework. The Commission considers that clearly defined performance standards and the imposition of penalties to achieve performance targets is a good approach to addressing service quality issues, and, therefore, the Commission has included maintaining service quality as an integral part of its first PBR principle. Service quality issues and the Commission's approach to maintaining service quality are addressed in Section 14 of this decision.

46. The Commission acknowledges the UCA's concerns about the capital forecasts filed by the companies in this proceeding and has addressed these concerns in this decision.

[36] Exhibit 634.01, UCA argument, paragraph 20, page 4.
[37] Exhibit 634.01, UCA argument, paragraph 28, page 5.

47. The Commission considers the UCA's first and third reasons for reconsidering and delaying implementation of PBR at this time to be closely related. Dr. Cronin argued that the regulatory burden does not go down under PBR and cites the Ontario PBR plans as an example. In the Commission's view, the type of PBR plan envisioned by Dr. Cronin would not decrease the overall regulatory burden because significant effort would still be required, although on different matters than under cost of service regulation. Dr. Cronin expressed his view that PBR plans require collecting significant amounts of information in order to carry out comparisons of the productivity and efficiency performance of various individual companies in Alberta with each other and with other North American companies. Dr. Cronin requires this information in order to determine how close those companies are to the "efficiency frontier"[38] and, therefore, their potential for efficiency improvements.[39] In addition, Dr. Cronin argued for the use of company-specific total factor productivity studies (which is also a data-intensive undertaking) to establish company-specific X factors. Dr. Cronin further suggested that comparisons of companies could be made at even more disaggregated levels, such as individual cost types or cost centres.[40]

48. In the Commission's view, adopting this type of an approach to PBR might very well increase the regulatory burden. Indeed, Dr. Cronin, in describing the approach used in Great Britain (one that appears to require the same type of information as that proposed by Dr. Cronin), stated that the regulator there "busies hundreds of analysts"[41] to give effect to its regulatory approach.

49. It is not the Commission's intention to build a PBR regulatory framework that requires or invites the Commission to manage the companies through analysis of and distinct incentive schemes for lower level cost data provided in company-specific TFP studies. Nor is it the Commission's intention to benchmark companies against each other or against an estimated efficiency frontier. In the ENMAX proceeding, Dr. Cronin expressed similar views to those expressed in this proceeding, and the Commission rejected them in Decision 2009-035, dealing with the ENMAX FBR proposal.[42] The Commission's objective is to provide incentives for improved efficiencies, both in the short run and the long run, as well as opportunities for the companies, without Commission direction and control, to discover and implement those efficiencies over longer time periods than they would have under the current regulatory framework. In the Commission's view, the PBR approach envisioned by the UCA would not achieve the objective of improving the efficiency of the regulatory process, nor would it satisfy the principle that**,** to the greatest extent possible, a PBR plan should create the same efficiency incentives as those experienced by companies in a competitive market. It would also not satisfy the principle that a PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

50. The Commission has also considered the UCA's view that PBR need not be implemented at this time because "based on the limited information available, it appears very likely the applicant utilities have superior performance, their rates are below or equal to other jurisdictions; their reliability is higher; and ROE is much higher than other jurisdictions."[43] The UCA's

[38] For further discussion on the efficiency frontier approach please refer to Section 6.2.
[39] Exhibit 634.01, UCA argument, paragraph 40, page 7.
[40] Transcript Volume 18, page 3420, line 8 to page 3422, line 7.
[41] Transcript, Volume 17, pages 3227, lines 15-16; Transcript, Volume 18, pages 3430-3431.
[42] Decision 2009-035, paragraph 175.
[43] Exhibit 634.01, UCA argument, paragraph 48, page 9.

conclusion is based on a benchmarking of the Alberta companies to a number of U.S. local distribution companies selected by Dr. Cronin.[44] These comparisons show that ENMAX's and EPCOR's local distribution rates are at the lower end of the range of rates of the selected companies and that Fortis is in the range of two local distribution companies in the northern states.[45] Information provided in response to an undertaking showed that ATCO Electric's local distribution rates are much higher than the other companies in the UCA's comparison group.[46]

51. The Commission is not satisfied that these comparisons can justify a decision to delay PBR until more information can be provided and analysed. ENMAX's rates are already regulated under a PBR plan. EPCOR has explained that a great deal of its local distribution network is in need of replacement. As a result, its rates can be expected to be lower because its capital-related costs included in rates will be lower than if the local network had already been substantially replaced. Indeed, as discussed in Section 7.3, the Commission's observation in this proceeding is that differences among the companies' capital proposals under PBR can be explained to some degree by where those companies are in the long term cycle of capital investment and replacement. Furthermore, this observation makes suspect the results of benchmarking across different regulated companies, whether Canadian companies or, as in the UCA analysis, U.S. companies. There may also be significant differences among the companies that cannot be accounted for in benchmarking studies.

52. Accordingly for all of the reasons stated above, the Commission is not persuaded by the UCA to reconsider or delay implementation of PBR for Alberta distribution companies.

53. The UCA has proposed that if the Commission proceeds at this time with PBR, it should engage in benchmarking and, if not benchmarking, then it should use a menu approach to PBR. If the menu approach is not employed by the Commission, the UCA recommended that the Commission adopt the ENMAX FBR model. The UCA's proposal for benchmarking and its menu approach to PBR are both addressed Section 6.2.

2.2 IPCAA's proposal

54. IPCAA objected to the full implementation of PBR at this time. IPCAA proposed the use of an I-X mechanism only for general and administrative (G&A) costs and the retention of cost of service regulation for the remaining costs (O&M (operating and maintenance) as well as capital-related costs). IPCAA's concern is that PBR creates incentives to reduce costs and that the Commission's current quality of service rules are not sufficient to protect service quality and asset condition. IPCAA, therefore, recommended a limited adoption of PBR until specific quality of service and asset condition performance metrics are implemented.[47]

Commission findings

55. The Commission understands IPCAA's concerns about the potential effects of the incentives created by PBR on service quality and the condition of the companies' capital assets. The Commission also recognizes that its own current quality of service rules may not be sufficient to properly address IPCAA's concerns or, indeed, the Commission's concerns under PBR. However, the Commission does not agree that these concerns must be addressed before a

[44] Exhibit 299.02, Cronin and Motluk UCA evidence, page 27.
[45] Exhibit 299.02, Cronin and Motluk UCA evidence, page 27; Exhibit 614.01, UCA undertaking.
[46] Exhibit 614.01, undertaking response given by Dr. Cronin.
[47] Exhibit 304.01, IPCAA policy evidence.

PBR plan can begin. The Commission is confident that its plans to address service quality and asset condition issues early in the PBR term will be sufficient to allow PBR to proceed. The Commission has taken into account IPCAA's concerns in its quality of service determinations and plans described in Section 14.

56. Furthermore, the Commission notes that IPCAA's proposal to include only G&A expenses in PBR would result in a negative effect on incentives because of the exclusion of a significant portion of the operations of a company from the I-X mechanism. Such an effect is well documented in this proceeding.[48] Therefore, based on all of the above, the Commission does not accept IPCAA's suggestion to limit the PBR plans to G&A expenses only.

2.3 EPCOR's proposal to exclude capital

57. EPCOR has proposed to exclude all capital-related costs from the application of the I-X mechanism.[49] The reason given by EPCOR is that it must embark on a major capital replacement program to address its aging local distribution system. EPCOR argued that, in its case, including all current capital-related expenses under the I-X mechanism and making provision for its significant capital additions outside of the I-X mechanism would be too complex to implement and could prevent EPCOR from making efficient capital decisions because of the way in which a capital mechanism outside of the I-X mechanism might be structured.

Commission findings

58. The Commission understands EPCOR's concerns but is itself concerned that excluding all capital from the I-X mechanism will not create new incentives to more optimally make efficient trade-offs between capital and maintenance and may serve to exacerbate the already significant incentives under a rate base rate-of-return framework to prefer capital investment over O&M expenses. In addition, the Commission is not satisfied that there is any acceptable way to create an X factor suitable for use for non-capital-related costs only. Therefore, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from application of the I-X mechanism. However, the Commission does address EPCOR's concerns about how its capital program can be treated outside of the I-X mechanism in Section 7.3.2.4 of this decision.

2.4 EPCOR's transmission proposal

59. In its February 26, 2010 letter, the Commission indicated that reform of rate regulation for electricity and natural gas transmission services would not be undertaken at that time because:

> The electricity transmission system is entering a period of significant change with substantial planned expansions while natural gas transportation rates are one subject of more extensive negotiations between the province's two largest regulated natural gas transportation service providers.[50]

48 Transcript, Volume 1, page 143, Dr. Makholm.
49 Exhibit 103.02, EPCOR application, pages 10-18.
50 Exhibit 1.01, AUC letter dated February 26, 2010, Rate regulation initiative round table.

60. Nonetheless, on July 15, 2010, the Commission released Bulletin 2010-20, which stated that "those distribution companies that are also transmission facility owners may choose to include their transmission components in the PBR plan if that is their preference."[51]

61. Of the Alberta distribution companies affected by the bulletin that also had an integrated transmission function, EPCOR was the only company that proposed to include its transmission component in its PBR plan. EPCOR explained that the highly integrated nature of its distribution and transmission functions allowed for economies of scale and scope and that a single, joint rate application for the two business operations reduced regulatory burden.[52]

62. As further outlined in the subsequent sections of this decision, EPCOR proposed that in its PBR plan, the I-X mechanism would apply only to the company's O&M and other non-capital costs, with capital expenditures treated as a flow-through item. EPCOR proposed this type of PBR plan for both its distribution and transmission functions.[53] In these circumstances, as discussed in Section 6.4.3, Dr. Cicchetti noted that an X factor for EPCOR should reflect the changes in O&M productivity only. Furthermore, because the O&M costs of EPCOR's distribution and transmission functions were similar in nature, Dr. Cicchetti offered that his recommended X factor was relevant to both functions:

> The two functions are highly integrated and interdependent, with shared management and staff, who utilize the same offices and other assets. There are common union settlements and the primary O&M input for both functions is labour. Accordingly, my recommendations apply to both functions.[54]

63. In its proposed PBR plan, EPCOR included four service quality performance measures and proposed targets for each of these measures along with a penalty adjustment in its formula for non-compliance with the performance targets. The four service quality performance measures were: Total Recordable Injury Frequency Rate (TRIF), System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI) and Service Connection Time (SCT).[55] For three of these measures, TRIF, SAIDI and SAIFI, EPCOR proposed to report combined distribution and transmission results.[56] During the hearing, EPCOR witnesses testified that there are no service quality issues that are unique to transmission.[57] As such, EPCOR concluded that its proposed service quality measures that combine distribution and transmission are "reasonable and workable."[58]

64. No party to this proceeding opposed the inclusion of EPCOR's transmission function in the company's PBR plan. However, the CCA and IPCAA expressed their concerns with the lack of relevant reliability metrics for transmission in Alberta to be used as service quality performance measures in PBR plans for electric transmission operations.

65. In argument and reply, IPCAA pointed to the absence of standard province-wide service quality measures for electric transmission services in Alberta. In IPCAA's view, a PBR

51 Exhibit 64.01, AUC Bulletin 2010-20, page 3.
52 Exhibit 103.02, EPCOR application, paragraph 14.
53 Exhibit 103.02, EPCOR application, paragraph 3.
54 Exhibit 103.05, Cicchetti evidence, pages 20-21.
55 Exhibit 630.02, EPCOR argument, paragraph 292.
56 Exhibit 630.02, EPCOR argument, paragraph 309.
57 Transcript, Volume 10, page 1813, lines 17-21.
58 Exhibit 646.02, EPCOR reply argument, paragraph 283.

mechanism for transmission facilities would be "far more complex and have much greater impact than at the distribution level," since the consequences of service quality degradation for transmission are much more severe than for distribution:

> Reductions in customer service quality at a POD [point-of-delivery where the distribution system connects to the transmission system] level will have an order of magnitude larger impact as transmission level outages affect either thousands of smaller customers at a [distribution company] point of delivery or large industrial facilities such as gas plants, refineries and oil sands facilities.[59]

66. Accordingly, IPCAA asserted that transmission service quality measures should be considered in a province-wide process. In IPCAA's view:

> Applying PBR to EDTI's transmission function could result in a piecemeal approach to transmission regulation, which is managed and delivered on a province-wide basis, and typically consists of large, capital intensive projects, the costs of which are flowed through to customers.[60]

67. The CCA expressed concern over the lack of data that EPCOR proposed to report in relation to transmission reliability and proposed that the Commission direct EPCOR to also report additional reliability measures such as energy not supplied, average interruption time and overhead line maintenance cost index for its transmission reliability. The CCA indicated that these measures are being used by other transmission companies.[61]

Commission findings

68. The Commission has two concerns with EPCOR's proposed inclusion of its transmission function under its PBR plan.

69. First, EPCOR's proposed X factor, which would be applicable to both its distribution and transmission functions under its PBR plan, is only for non-capital costs. Dr. Cicchetti stated that because the O&M costs of EPCOR's distribution and transmission functions were similar in nature, his recommended X factor (calculated using the O&M data for the distribution component of NERA's sample) was relevant to both functions.[62] In the Commission's view, it is uncertain whether the same conclusion can be reached when the X factor is calculated based on the entirety of the costs (both O&M and capital) of the company.

70. In its productivity study, NERA measured the TFP of the distribution component of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[63]

71. As explained above, the Commission has not accepted EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs in its PBR plan. No evidence was filed in this proceeding on what the relevant X factor for the electric transmission function should be if the I-X mechanism is applied to both O&M and capital costs.

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59 Exhibit 635.01, IPCAA argument, paragraph 75.
60 Exhibit 642.01, IPCAA reply argument, paragraph 38.
61 Exhibit 636.01, CCA argument, paragraphs 363-365.
62 Exhibit 103.04, Cicchetti evidence, pages 20-21.
63 Exhibit 80.02, NERA report, page 6.

Accordingly, the Commission cannot set an X factor for EPCOR if the transmission function is included in the plan.

72. Second, EPCOR's proposed measures, targets and penalties to ensure service quality were proposed in the context of a PBR plan that excludes capital-related costs from the rates subject to the I-X mechanism. It is unclear whether these measures, targets and penalties would be adequate to ensure transmission service quality for a PBR plan that is not restricted in this manner. EPCOR's proposals for service quality measures are further discussed in Section 14.

73. The creation of reliability standards and performance targets for transmission is still under development. Unlike transmission, the Commission has been monitoring service quality performance through AUC Rule 002[64] for electric utilities and gas distributors. While further measures and performance targets will be developed as part of AUC Rule 002, as discussed in Section 14, there has been a history of measuring and reporting performance for the distribution function with which companies and industry stakeholders are familiar. There is no similar starting point for transmission.

74. In light of the above considerations, the Commission finds that transmission services should not be a part of EPCOR's PBR plan. EPCOR's transmission services will continue to be regulated under cost of service regulation.

3 Going-in rates

3.1 Purpose and background

75. Going-in rates are the starting rates for the implementation of a PBR (performance-based regulation) plan. The going-in rates are sometimes referred to as "year zero rates." They are the rates to which the approved PBR formula is applied to determine the rates to be charged to customers during the first year of the PBR term. Thereafter, the current year's rates are adjusted by the PBR formula to determine the upcoming year's rates until the end of the PBR term.

76. In Decision 2009-035,[65] the Commission determined that ENMAX's going-in rates were to be based on the company's revenue requirement as determined in a forecast cost of service rate setting proceeding.[66] The Commission directed that the going-in rates for ENMAX would be its approved 2006 rates, adjusted to include previously disallowed short term incentive plan costs. With respect to adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs, the Commission stated that it would "not accept adjustments to the going-in rates to account for 2006 actual results."[67] The Commission further stated that: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[68] The Commission accepted a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was approved on

[64] AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective July 1, 2010 (Rule 002).
[65] Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009.
[66] Decision 2009-035, paragraph 72.
[67] Decision 2009-035, paragraph 73.
[68] Decision 2009-035, paragraph 74.

the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent "operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan."[69]

77. In a December 16, 2010 letter granting deadline extensions for the filing of the companies' PBR proposals in this proceeding, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used by the Commission to establish the going-in rates for the companies.

3.2 Proposals for going-in rates

78. All of the companies proposed that their 2012 approved rates be used as the basis for their going-in rates. In addition, all of the companies, with the exception of EPCOR, proposed adjustments to their 2012 approved rates in setting going-in rates for the PBR term. The companies collectively proposed a total of nine individual adjustments to their going-in rates. Like ATCO Electric and ATCO Gas, AltaGas stated that its adjustments were necessary to earn a fair rate of return during the PBR plan.[70]

79. EPCOR pointed to Decision 2009-035 in proposing that its 2012 approved distribution and transmission tariffs be used as the going-in rates for the company's PBR plan[71] without adjustment. In UCA-EDTI-10(b) EPCOR stated:

> The approved distribution rates and transmission revenue requirement will form EDTI's going-in rates and revenue requirement and, for many of the same reasons stated by the Commission in Decision 2009-35 [sic.], no adjustments to those rates for PBR purposes will be necessary or warranted. If the rates and revenue requirement are just and reasonable for 2012, they will also be just and reasonable as EDTI's going-in rates and revenue requirement. As the Commission indicated in Decision 2009-035, costs and financial results will fluctuate from year to year over the PBR Term. In some years, costs will be higher than expected and in other years lower, EDTI will be incented to improve its efficiency and productivity and under EDTI's PBR Plan, some of these gains will be shared with customers and some will be retained by EDTI.[72]

80. AltaGas requested that its going-in rates be based on its 2012 distribution rates approved in response to its 2010 to 2012 GRA (general rate application) subject to certain adjustments. ATCO Electric and ATCO Gas proposed to use their 2012 final distribution rates as the basis for the going-in rates for the PBR term subject to certain adjustments.[73] Fortis also proposed to use its 2012 approved rates as the basis for its going-in rates but requested that the rates be adjusted to reflect its 2013 opening rate base balance, which would recognize 2012 actual capital expenditures.[74]

69 Decision 2009-035, paragraph 79.
70 Exhibit 628.01, AltaGas argument, page 81; Exhibit 628.01, AltaGas argument, page 80; Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.
71 Exhibit 103.02, EPCOR application, page 2.
72 Exhibit 238.01, EPCOR information responses, pages 25 and 26.
73 Exhibit 98.02, ATCO Electric application, paragraph 208 and Exhibit 99.01, ATCO Gas application, paragraph 10.
74 Exhibit 100.02, Fortis application, page 11.

81. There were no objections by interveners to the companies' proposals that the 2012 approved rates be used as the starting point for going-in rates in the PBR term. The CCA stated that, for the purposes of going-in rates, the approved revenue requirements have been set by rigorous cost of service regulatory oversight. However, the CCA stated that it was uncertain of the finality of these revenue requirements because of placeholders or the potential impact of other adjustments for outstanding appeals or applications.[75]

82. The UCA recommended that the "going-in rates must include recognition of efficiency gains achieved in the last cost of service test period."[76] IPCAA and the CCA did not provide argument on going-in rates but agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.[77]

Commission findings

83. Prior to initiating the current proceeding, the Commission considered two alternatives for establishing the going-in rates at the commencement of the PBR term. The first alternative was to use the actual results for the immediately preceding year, in this case 2012, and adjust the 2012 approved rates to reflect the actual 2012 results to form the basis for the going-in rates for PBR. This approach would account for any expenses that were not forecast in the 2012 revenue requirement and any unaccounted for efficiency gains realized in 2012, all subject to a prudency review. However, the Commission recognized that the actual results for 2012 would not be available until well into 2013 and that a prudency review of these results would require a significant regulatory process. The Commission did not adopt this approach because it is inconsistent with the Commission's objective to implement PBR effective January 1, 2013 as set out in the Commission's letter of December 16, 2010.[78]

84. The other alternative was to adopt the approach approved in Decision 2009-035 which uses rates approved in the most recent revenue requirement proceeding as the basis for establishing the going-in rates.

85. In an effort to promote regulatory efficiency, and so as not to delay the commencement of PBR, the Commission in its December 16, 2010 letter, adopted the approach approved in Decision 2009-035 and directed that the companies' approved rates for 2012 would be used as the basis for establishing going-in rates. Accordingly, rates that will form the basis for the going-in rates for PBR will have been established in the context of a full rate case, or in the case of Fortis, on the basis of a negotiated settlement approved by the Commission.

86. With respect to proposed adjustments to going-in rates, the Commission again has two alternatives. The first alternative is to consider making adjustments to include certain costs that were either not forecast or otherwise approved for inclusion in the 2012 revenue requirement, as proposed by certain of the companies. In this context, the Commission could also consider an adjustment to going-in rates to reflect efficiency gains that may have occurred in 2012 that were not already reflected in 2012 approved rates, as proposed by interveners.

75 Exhibit 636.01, CCA argument, paragraph 11.
76 Exhibit 634.01, UCA argument, page 72.
77 Exhibit 642.01, IPCAA reply argument, paragraph 62.
78 Exhibit 79.01, AUC letter dated December 16, 2010, Request for deadline extensions.
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87. The second alternative is to again adopt the approach followed in Decision 2009-035. In that decision the Commission rejected the adjustments to going-in rates proposed by ENMAX and interveners to reflect certain actual 2006 costs. The Commission stated that it would "not accept adjustments to the going-in rates to account for 2006 actual results."[79] The Commission further stated that: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[80] The Commission did accept however, a single adjustment to going-in rates to include previously disallowed short term incentive plan costs. This adjustment was accepted on the basis that ENMAX had addressed the concerns that had led to the original disallowance of these costs from inclusion in the 2006 revenue requirement and that the revised short term incentive plan had been designed to incent "operational efficiency improvements and, as such, complements the incentives created by a formula based regulation plan."[81] The Commission found that an adjustment of this kind "is qualitatively different from rate adjustments made after the fact to reflect actual results."[82]

88. The Commission considers the second alternative is in keeping with the decision to use 2012 approved rates rather than 2012 actual costs as the basis for going-in rates. The 2012 rates have been tested and approved by the Commission as just and reasonable for 2012. Accordingly, the 2012 approved rates are the correct starting point on which to base going-in rates. The Commission confirms the findings in Decision 2009-035 that adjustments to going-in rates should not be made to reflect actual results. Further, adjustments should not be made selectively but, rather, should only be made in the context of a full rate case. Adjustments may be made in exceptional situations, however, like the case of the short term incentive plan adjustment approved in the ENMAX decision.

89. Accordingly, the Commission will consider adjustments that are in the nature of a correction to the going-in rates, and which are not rate adjustments made after-the-fact to reflect actual results. This approach is consistent with the Commission's finding in Section 7.4.4 that differences between placeholder amounts and final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

90. The Commission will consider each of the proposals of the companies and interveners to include adjustments to going-in rates.

91. Given the above findings, the Commission directs the companies to use their respective approved 2012 distribution rates as the going-in rates for the PBR term, subject to the specific adjustments allowed below.

3.3 Requests for adjustments to going-in rates

3.3.1 UCA requested adjustment for efficiency gains

92. The UCA recommended that efficiencies achieved by the companies prior to the commencement of the PBR term should be reflected in going-in rates. The UCA stated that prior to the implementation of PBR, the utilities had undertaken projects that will create new

[79] Decision 2009-035, paragraph 73.
[80] Decision 2009-035, paragraph 74.
[81] Decision 2009-035, paragraph 79.
[82] Decision 2009-035, paragraph 81.

efficiencies. However, none of the applications included any "mechanism or adjustment to allow customers to benefit from these efficiencies in going-in rates."[83]

93. The UCA identified two specific adjustments for ATCO Gas to account for efficiency gains: one to remove the costs of old facilities from going-in rates and one to remove certain costs for meter reading to account for the adoption of automated meter reading in 2012.[84]

94. IPCAA and the CCA agreed with the UCA that efficiency gains achieved under cost of service regulation should be recognized in going-in rates.[85]

95. EPCOR disagreed with the UCA's proposed adjustments to going-in rates for efficiencies achieved under cost of service regulation and pointed to its actual return on equity being close to or below the target ROE.[86] The ATCO companies argued that the 2011 to 2012 distribution rates proceedings included a forecast of anticipated productivity improvements. The ATCO companies argued, "there is a danger that any adjustment could be giving customers the benefit of those productivity improvements twice, because they have already been incorporated into the 2012 going-in revenue for PBR."[87]

Commission findings

96. As stated in Section 3.2 above, it is the Commission's view that adjustments to going-in rates should not be made to reflect actual costs incurred in the test year which form the basis for the going-in rates. Adjustments should only be made in the context of a full rate case. Accordingly, the Commission denies adjustments to reflect possible efficiency gains in a prior period that are not captured in the going-in rates. This finding is consistent with the Commission's determination in Decision 2009-035 which denied the UCA's request to reduce going-in rates by an amount to reflect actual costs incurred in the test year just as it disallowed ENMAX's request for increases to the going-in rates to reflect higher actual costs.[88]

3.3.2 Company proposals

3.3.2.1 Proposals to move from mid-year to end-of-year for rate base purposes

97. ATCO Electric requested an adjustment to its 2012 distribution rates to move from a mid-year calculation of rate base to an end-of-year calculation of rate base to reflect the full impact of its 2012 capital investment.[89] ATCO Electric submitted that the Commission has approved the full amount of the costs relating to its 2012 capital investment, totalling $367 million, in the company's revenue requirement in its 2011 to 2012 General Tariff Application.[90] ATCO Electric's mid-year rate base was $1.392 billion compared to its end-of-year rate base of $1.508 billion. The capital related costs include financing costs, income tax, and depreciation.[91] Based on the evidence of Dr. Carpenter, ATCO Electric submitted that NERA's TFP study to be used for calculating X does not compensate ATCO Electric for the full year impact of

[83] Exhibit 634.01, UCA argument, page 72.
[84] Exhibit 300.02, UCA evidence of Russ Bell, pages 87 to 89.
[85] Exhibit 642.01, IPCAA reply argument, paragraph 62 and Exhibit 636.01, CCA argument, paragraph 375.
[86] Exhibit 646.02, EPCOR reply argument, paragraph 302.
[87] Exhibit 647.01, ATCO Electric reply argument, paragraph 246 and Exhibit 648.02, ATCO Gas reply argument, paragraph 518.
[88] Decision 2009-035, paragraph 83.
[89] Exhibit 98.02, ATCO Electric application, paragraphs 215 to 220.
[90] Exhibit 98.02, ATCO Electric application, paragraphs 215 and 216 and Decision 2011-134.
[91] Exhibit 98.02, ATCO Electric application, paragraphs 217 and 218.

2012 additions that were not incorporated in the 2012 rates. Dr. Carpenter's evidence purported to show that NERA's study is based on a rate base growth of peer group utilities of 4.5 per cent and the company had an approximate rate base growth of 17 per cent in 2012.[92]

98. ATCO Gas also proposed to use end-of-year values rather than applying the mid-year convention for its rate base calculations in order to reflect the full impact of its 2012 capital investments.[93] ATCO Gas submitted that the mid-year convention is used in order to recognize that not all investments occur on the first day of January. In employing the mid-year convention, the revenue requirement is adjusted to reflect the full year costs including depreciation, income tax, and carrying costs for the prior year's investment[94] but an adjustment for capital investments is required to fully recognize the investments in going-in rates.

99. Interveners disagreed with the proposal to use end-of-year investment values to determine rate base. Calgary stated that the effect of moving from the mid-year convention to the end-of-year is to increase the baseline revenue requirement. Calgary argued that, "AG's approach has the effect of increasing the baseline revenue requirement – the starting point for the revenue trajectory – over and above the point at which the Commission has already deemed reasonable from the approved revenue requirement."[95] It would also be inconsistent with its proposed use of average number of customers in ATCO Gas's PBR formula.[96]

100. The CCA supported Calgary's position and argued that ATCO Gas' request should not be approved.[97]

Commission findings

101. The mid-year rate base convention is the accepted method for approximating the cost of capital investments in the year, and for the purposes of calculating other capital related costs. The mid-year convention uses an arithmetical average of a utility's investments to account for capital related costs uniformly over the entire year, recognizing that assets are added to rate base throughout the year. It is commonly used in regulatory jurisdictions in North America.

102. Had a cost of service rate application been filed for 2013, it would have accounted for 2012 capital expenditures in opening plant balances for rate base and an entire year's operating expenses for the use of those assets. However, 2013 capital expenditures would still be subject to the mid-year convention. In its December 16, 2010 letter, the Commission determined that the forthcoming rate decisions for the 2012 test year will be used to establish the going-in rates for the companies. Therefore, PBR will take these going-in rates and will in effect apply the I-X mechanism to the mid-year rate base. Carrying forward the mid-year forecast balance of rate base in the 2012 rates into the going-in rates continues to reflect the fact that new capital assets are put into service throughout the year. The Commission finds that the introduction of PBR does not require a departure from the use of the mid-year convention. No evidence was provided that other regulators employ this practice in adopting a PBR plan.

92 Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 76.
93 Exhibit 99.01, ATCO Gas application, page 45-46.
94 Exhibit 99.01, ATCO Gas application, paragraph 132.
95 Exhibit 298.02, Calgary evidence, page 49, paragraph 176.
96 Exhibit 629.01, Calgary argument, page 69.
97 Exhibit 636.01, CCA argument, paragraphs 230 and 231.

103. The Commission finds no compelling reason to depart from the use of the mid-year convention. Accordingly, the Commission denies ATCO Electric's and ATCO Gas' proposal to use 2012 end-of-year forecast values rather than applying the mid-year convention for the rate base calculations included in going-in rates.

3.4 Individual adjustments to going-in rates requested by the companies

3.4.1 Fortis

104. Fortis proposed to update its 2013 opening values to reflect 2012 actual capital expenditures and related effects.[98] Fortis also proposed two adjustments to account for the full cost of a distribution control centre and one for depreciation rates.

105. At the hearing, Fortis requested a one-time adjustment to going-in rates to reflect the full cost of a distribution control center.[99] This adjustment was required because the timing of the distribution control centre implementation changed and now falls between 2012 and 2013.

106. With respect to the depreciation rates, Fortis proposed an adjustment to the depreciation rates established in its negotiated settlement. The negotiated settlement was signed on November 7, 2011 and approved by the Commission on April 18, 2012 in Decision 2012-108.[100] Fortis argued that "going-in rates for depreciation costs alone are fine on a going in basis" but due to Fortis' PBR assumptions the going-in rates should recognize "$60 million more of rate base compared to the plan assumptions when we set our PBR proposal."[101]

3.4.2 ATCO Electric

107. ATCO Electric requested two adjustments: one to include the final 2012 costs for three buildings and an adjustment for capitalized pension costs.

108. ATCO Electric proposed adjustments to its 2012 distribution rates to recognize full forecast costs and property taxes for three buildings with in-service dates falling in the second half of 2012.[102] The three buildings are located in Grande Prairie, Lloydminster, and Stettler.

109. ATCO Electric also proposed an adjustment to remove the cash basis current year recovery of its capitalized pension costs from going-in rates.[103] ATCO Gas removed the cash basis current year recovery of capitalized pension costs in its 2011 to 2012 general rate application[104] and ATCO Electric sought a similar change to ensure distribution pension costs were treated in the same manner by both ATCO companies. ATCO Electric therefore is no longer seeking cash basis current year recovery of capitalized pension costs.[105] Consequently, an

98 Exhibit 100.02, Fortis application, paragraph 42.
99 Exhibit 633, Fortis argument, page 122.
100 Decision 2012-108: FortisAlberta Inc, Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.
101 Testimony of Mr. Lorimer, Transcript, Volume 11, pages 2184-2188 as quoted in Fortis argument, Exhibit 633.01, pages 121-122.
102 Exhibit 98.02, ATCO Electric application, paragraphs 210-214.
103 Exhibit 98.02, ATCO Electric application. paragraphs 221 and 222.
104 Decision 2011-450 ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.) 2011-2012 General Rate Application Phase I, Application No, 1606822, Proceeding ID. No, December 5, 2011, paragraph 5, Table 2 shows capital pension – removal of immediate collection: costs of $13,257,000 were removed for 2012.
105 Exhibit 98.02, ATCO Electric application, paragraphs 221 and 222.

adjustment to going-in rates is required to reflect the change in recovery of these costs. In Application No. 1608750 (Proceeding ID No. 2078, the ATCO Utilities Compliance with Decision 2012-166[106]) filed on August 15, 2012, the Commission has been requested to determine the adjustment required to reflect the removal of the cash basis current year recovery of capitalized pension costs from the 2012 revenue requirement for ATCO Electric. ATCO Electric stated that the adjustment of capitalized pension costs was not commented on by interveners and it should be approved.[107]

3.4.3 ATCO Gas

110. ATCO Gas proposed an adjustment to going-in rates to account for the actual 2011 to 2012 urban mains replacement (UMR) capital expenditures in excess of the forecasts approved in Decision 2011-450.[108] ATCO Gas requested the opportunity to file a future application for an adjustment to its 2012 going-in revenue requirement for its actual 2011 to 2012 UMR expenditures. ATCO Gas submitted this approach is consistent with the mid-year convention and the effect on 2012 capital investment is consistent with what would occur under a cost of service rates application had one been filed to set rates for 2013.[109] ATCO Gas stated:

> The findings of the Commission on this matter are similar to the findings of the AEUB in Decision 2003-072, where the Board held ATCO Gas' UMR expenditures at approximately $7 million per year for the years 2003 and 2004.1 In the 2005 –2007 GRA, ATCO Gas was able to support the prudence of the actual UMR projects undertaken in 2003 and 2004, at a total cost of approximately $22 million, rather than the $14 million that had been approved.[110]

111. ATCO Gas stated that "[i]t is not reasonable to expect ATCO Gas to carry the cost of these prudent investments over the full term of its PBR Plan."[111] It further stated with respect to the ability to recover these UMR costs: "[t]o not provide ATCO Gas with this ability increases the risk to the utility, and it prevents ATCO Gas from having a reasonable opportunity to recover its prudently incurred costs, including a fair return."[112]

3.4.4 AltaGas

112. AltaGas proposed four adjustments to going-in rates: annualization of costs associated with monthly meter reading, income tax timing differences between 2012 and 2013, including losses carried forward, impacts of changes in pension expense from 2012 to 2013, and recovery of 2013 Natural Gas System Settlement Code (NGSSC) capital forecasts and annualization of capital and O&M expenses related to NGSSC costs.[113] AltaGas stated that its proposed annualized adjustments for metering and NGSSC costs are required in order for it to earn a fair return.[114]

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[106] Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.), 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.
[107] Exhibit 631.01, ATCO Electric argument, paragraph 318.
[108] Exhibit 389.01, ATCO Gas update, page 5 and 6.
[109] Exhibit 389.01, ATCO Gas application update, paragraph 8.
[110] Exhibit 389.01, ATCO Gas update, page 2, paragraph 4.
[111] Exhibit 389.01, ATCO Gas update, page 3, paragraph 5.
[112] Exhibit 389.01, ATCO Gas update, page 4, paragraph 7.
[113] Exhibit 628.01, AltaGas argument, pages 80 and 81.
[114] Exhibit 628.01, AltaGas argument, paragraph 273.

113. AltaGas proposed its 2012 distribution rates be adjusted to reflect changes in income taxes and depreciation.[115] The adjustment for income taxes is intended to recognize changes in income tax timing differences between 2012 and 2013, including losses carried forward.[116] AltaGas has requested an adjustment to account for a forecast change from 2012 to 2013 related to income taxes. This adjustment would be for book to tax timing differences.[117] In the hearing, AltaGas was asked about its proposal to adjust taxes to reflect a reduced level of capital cost allowance. The AltaGas witness responded:

> Well, our proposal is that the going-in rates be adjusted to allow for the increase in the income taxes, the cash income tax, expense the company will be incurring as a result of the -- of its ability to claim an equivalent CCA amount as it had in 2012. In other words, in 2012 because AUI was able to claim maximum CCA at the direction of the Commission, it effectively reduces its cash taxes to zero. So there is in fact zero dollars for income taxes sitting in the revenue requirement, which would drive the going-in rates. So we're simply asking that the company be allowed to have a component for income taxes in its going-in rates, which would be the equivalent of what it would require under normal circumstances.[118]

114. AltaGas also proposed an adjustment for the impact of changes in pension expenses from 2012 to 2013.[119] On April 18, 2012, AltaGas provided corrections and updates to its application.[120] AltaGas stated, with respect to meter reading that, due to the timing of Decision 2012-091, AltaGas "will not be able to commence the additional readings until July 1, 2012. As AltaGas' intention is to adjust its 2012 revenue requirement in its compliance filing to reflect only a half year of the additional costs, it will be necessary to make an adjustment to going-in rates to reflect the full year of costs."[121] AltaGas also asked to reserve the right to apply for a going-in adjustment for the NGSSC capital cost forecast for adjustments not included in its 2012 compliance filing.[122]

Commission findings

115. The Commission considers that each of the individual adjustments to going-in rates except for the those items specifically referred to below are requests to adjust approved 2012 revenue requirements for after-the-fact events or circumstances and are therefore denied. The Commission has confirmed the position taken in Decision 2009-035 that it will not accept adjustments to the going-in rates to account for 2012 actual results. As noted in that decision: "[a]djustments to account for actual results should not be made selectively but, rather, should only be made in the context of a full rate case which would consider the forecast costs for a subsequent time period."[123]

116. However, the Commission will allow the ATCO Electric requested adjustment to going-in rates to remove its cash basis current year recovery of capitalized pension costs. In

[115] Exhibit 110.01, AltaGas application, page 12, paragraph 44.
[116] Exhibit 628.02, AltaGas argument, page 80.
[117] Exhibit 110.01, AltaGas application, paragraph 44.
[118] Transcript, Volume 9, page 1610, lines 10 to 23, AltaGas witness Mr. Mantei in response to cross-examination by CCA counsel.
[119] Exhibit 628.01, AltaGas argument, pages 80-81.
[120] Exhibit 529, AltaGas corrections and amendments to AltaGas' application.
[121] Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.
[122] Exhibit 529, AltaGas corrections and amendments to AltaGas' application, pages 4 and 5.
[123] Decision 2009-035, paragraph 74.

Decision 2012-166[124] the Commission approved the request of the ATCO Utilities to no longer collect the capital component of pension costs in the current year on a cash basis and to fund it as part of each utility's invested capital.[125] Given this decision and ATCO Gas' removal of similar costs in its general rate application, the Commission considers that this adjustment provides for consistent treatment between the ATCO distribution companies for the purpose of setting going-in rates for PBR. The requested adjustment is similar in nature to the adjustment to going-in rates permitted in Decision 2009-035 for the inclusion of ENMAX short term incentive plan costs. It is also similar to the replacement of a placeholder, and is not a rate adjustment made after-the-fact to reflect actual results. The Commission grants ATCO Electric's removal of its cash basis current year recovery of capitalized pension costs for the purposes of establishing going-in rates. The necessary adjustment to 2012 revenue requirement will be determined by the Commission in Proceeding ID. 2078. With respect to AltaGas' NGSSC costs for 2012, the Commission determined in Decision 2012-091, that the evaluation of AltaGas' 2012 forecast costs for NGSSC will be determined in AltaGas' compliance filing to its general rate application.[126] The Commission's decision on AltaGas' compliance filing to its general rate application will establish the final rates for 2012. These rates will form the basis for the going-in rates for PBR and, as a result, recovery of NGSSC costs in 2013 are already accounted for, adjusted by I-X. Accordingly, there is no need for an adjustment for NGSSC costs in AltaGas' going-in rates. With respect to AltaGas' request for a going-in rates adjustment for tax timing differences, the Commission has addressed this issue in Section 7.4.2.3.5 by indicating that book-to-tax timing differences should be the subject of a Y factor application.

3.5 Other adjustments to going-in rates

117. Certain parties to this proceeding requested removal of all deferral accounts and other Y factor adjustments from their 2012 revenue requirements. For instance, ATCO Gas requested removing the amounts included 2012 approved revenue requirement corresponding to deferral accounts treated as Y factor adjustments under PBR.[127]

Commission findings

118. The removal from going-in rates of amounts corresponding to approved Y factor items from going-in rates is discussed in Section 7.4.4 of this decision.

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124 Decision 2012-166: ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) 2011 Pension Common Matters Compliance Filing, Application No. 1607949, Proceeding ID No. 1599, June 14, 2012.

125 Decision 2012-166, paragraph 70.

126 AltaGas Utilities Inc. Compliance Filing Proceeding ID No. 1921 and Decision 2012-091, AltaGas Utilities Inc, 2010 to 2012 General Rate Application – Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012.

127 Exhibit 99.01, ATCO Gas application paragraph 135 and Exhibit 632.01, ATCO Gas argument, paragraph 330.

4 Price cap or revenue cap

119. The electric distribution companies (ATCO Electric, EPCOR and Fortis) proposed that their PBR (performance-based regulation) plans take the form of a price cap. Under a price cap plan, a company is allowed to change its customer rates according to an indexing formula that is typically comprised of an inflation measure, known as the I factor, and a productivity offset, commonly referred to as the X factor. An illustrative generic formula describing a typical price cap plan can be written as follows:

For each customer class:

$$\textbf{Rates}_t = \textbf{Rates}_{t-1} * (1 + I - X) \pm \textbf{Other Adjustments}$$

120. As the formula above illustrates, the current year's customer rates for each class are derived by adjusting the previous year's rates by a percentage equal to the difference between the relevant I and X factors (as well as any other allowed or mandated adjustments discussed in other sections of this decision).

121. A price cap plan establishes annual customer rates regardless of the amount of energy transported through a company's system. Accordingly, under price cap plans the company ordinarily bears the risk of a change in energy volumes transported through its system. An increase in the amount of energy transported would lead to an increase in the company's revenues, and a decrease in the amount of energy transported would lead to a decrease in the company's revenues. As a result, parties to this proceeding pointed out that the use of price caps can be problematic when there is expected to be a continuing decline in sales per customer.

122. ATCO Gas and AltaGas both presented evidence that average gas deliveries per customer had been declining for most customer classes in Alberta and for several years and were expected to continue to decline. The average decline rate for ATCO Gas and AltaGas was approximately 1.5 per cent per year.[128] No party took issue with this evidence. Dr. Lowry, on behalf of the CCA, also confirmed that declines in average use by small-volume customers have been common in the gas distribution industry for many years. Contributing factors include demand side management (DSM) programs, general improvements in the technology of furnaces and other gas-fired equipment, and changes in building codes and appliance efficiency standards.[129] None of the electric distribution companies indicated a similar trend in declining use per customer.[130]

123. Because the rates charged by ATCO Gas and AltaGas are composed of fixed and variable components, a significant portion of revenue for both companies is determined by actual deliveries. The gas distribution companies submitted that a price cap plan would result in chronic revenue shortfalls in an environment of declining deliveries per customer.[131] To address this issue, both gas distributors, ATCO Gas and AltaGas, proposed that their PBR plans take form of a revenue-per-customer cap.

124. A revenue-per-customer cap is similar to the price cap plans discussed above. However, instead of limiting the change in customer rates from one year to the next, it limits the change in

[128] Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).
[129] Exhibit 307.01, PEG evidence, page 17.
[130] Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.
[131] Exhibit 632, ATCO Gas argument, paragraph 141 and Exhibit 628, AltaGas argument, page 35.

a company's revenue per customer on a class by class basis, as illustrated by the following general formula:

For each customer class:

$$\textbf{Revenue per customer}_t = \textbf{Revenue per customer}_{t-1} * (1 + I - X) \pm \textbf{Other Adjustments}$$

125. Under a revenue-per-customer cap plan, the approved revenue per customer from the previous year is adjusted by the I-X index on a class by class basis to arrive at the upcoming year's revenue-per-customer cap. However, to calculate actual customer rates, the indexed revenue must be divided by the forecast consumption per customer on a class by class basis. Consequently, unlike in a price cap plan, forecast billing determinants represent an integral part of the revenue cap mechanism, regardless of any other adjustments outside of the I-X indexing mechanism.

126. Both gas distribution companies indicated that a revenue cap plan is common for natural gas distribution companies in Canada because it allows the company to update its billing determinants and adjust its rates to account for the effect of the declining use per customer that is common to the natural gas industry.[132] ATCO Gas highlighted the fact that PBR plans in the form of revenue cap plans were previously approved by the regulators for other Canadian gas distribution companies, including Enbridge Gas, Gaz Métro and Terasen Gas.[133]

127. As AltaGas explained in its evidence, PBR plans designed in the form of price caps are not consistent with the underlying cost structure of gas distribution companies. AltaGas pointed out that the total cost of gas distribution largely depends on the capacity required to provide for maximum daily throughput (peak loads) and transport distances (or the length of distribution line), and is largely unrelated to total energy use. However, these predominately fixed costs are mostly recovered through variable charges, for example dollars per gigajoule delivered. As a result, while changes in use per customer have virtually no impact on cost, they have a direct impact on the company's total revenues.[134]

128. This effect is further amplified by the economies of density[135] in the gas distribution industry, with the result that the price charged for an additional unit of gas delivered to customers is typically above the marginal cost of delivery. In such circumstances, increases in use per customer will increase revenue more rapidly than costs and, conversely, decreases in use per customer will decrease revenue more rapidly than costs. Consequently, unexpected changes in use per customer may lead to "windfall profits or extraordinary losses."[136] More importantly in the context of Alberta gas distribution companies, when use per customer is expected to decline on a continuing basis, the revenue decline will be fairly certain. By focusing on revenue per customer as opposed to the price per unit of gas delivered, the revenue cap approach to PBR is designed to account for the revenue decline associated with declining use per customer.

[132] Exhibit 99.01, ATCO Gas application, paragraph 19 and Transcript, Volume 8, page 1364, lines 18-20.
[133] Transcript, Volume 3, page 551, line 2 to page 552, line 2.
[134] Exhibit 477.01, AltaGas rebuttal evidence, paragraph 18.
[135] As AltaGas explained in its evidence, economies of density exist when an increase in usage to a customer on the network leads to a less than proportional increase in total costs. In gas distribution, costs are primarily related to connecting a customer to the network and are not related to the customer's use, leading to economies of density. (Exhibit 110.01, footnote 1 on page 2).
[136] Exhibit 110.01, Christensen Associates evidence, paragraph 7.

129. The CCA stated that revenue caps sidestep the need for the very low X factors that would otherwise be needed to provide compensatory rate escalation in the circumstances where average use by small-volume customers has a markedly downward trend.[137] This view was shared by Calgary.[138]

130. With respect to the incentive properties of the proposed PBR plans, parties to this proceeding agreed that both price cap and revenue cap formulas create similar incentives to minimize costs.[139] In fact, both gas companies pointed out that they would be indifferent as between a price cap plan and a revenue cap plan if there were a deferral account or some other revenue adjustment mechanism to account for changes in use per customer under the price cap plan. However, neither company favoured the use of a price cap plan with the adjustment mechanism due to the increased complexity and administrative burden of such approach as compared to the proposed revenue-per-customer cap plans.[140]

131. At the same time, NERA pointed out that price caps and revenue caps differ with regard to their potential impact on sales (either in total or on a per-customer basis) and in the incentive to maintain quality. NERA explained that a firm under a price cap plan has an incentive to increase sales if its additional revenues from new sales exceed its incremental costs. Firms under a revenue cap plan do not have such an incentive. Additionally, NERA noted that service quality can be more of a concern under revenue caps than price caps because, under a revenue cap, if poor service quality leads to fewer sales, the lost revenue can be made up through the price increases for remaining customers that arise from application of the formula.[141]

132. Parties also observed that a revenue-per-customer cap plan would diminish the disincentive a company has to promote the DSM measures. AltaGas noted that, because the price it charges for the delivery of gas is typically greater than the marginal cost for the service, any reduction in gas consumption will have a greater impact on revenues than costs. Thus, under a price cap plan, it is in the financial interest of the company to limit the reduction in customer use and, instead, encourage increased consumption, if possible.[142] The CCA experts reached a similar conclusion and pointed out that revenue cap plans mitigate the disincentive to promote DSM plans by weakening the link between changes in system use (e.g., energy deliveries and peak demand) and changes in earnings.[143] However, Ms. Frayer on behalf of Fortis pointed out that revenue caps may create distorted incentives for companies to act like monopolists, raising prices while reducing output in order to maximize profit margins, giving rise to the so-called “Crew-Kleindorfer effect.”[144]

133. AltaGas submitted that, unlike a revenue cap formula that applies to a firm’s overall revenue, the proposed revenue-per-customer cap approach provides an incentive to continue connecting new customers because customer growth drives revenue growth. In contrast, a straight revenue cap formula would not provide such an incentive because under a revenue cap

137 Exhibit 307.01, PEG evidence, page 16.
138 Transcript, Volume 15, page 2926, lines 23-35 and page 2927, lines 1-11.
139 Exhibit 195.01, AUC-NERA-13; Exhibit 628, AltaGas argument, page 35; Exhibit 629, Calgary argument, page 37.
140 Exhibit 632.01, ATCO Gas argument, page 44 and Exhibit 628.01, AltaGas argument, page 35.
141 Exhibit 195.01, AUC-NERA-13.
142 Exhibit 110.01, Christensen Associates evidence, paragraph 8.
143 Exhibit 307.01, PEG evidence, page 16.
144 Exhibit 100.02, Frayer evidence, page 23.

approach the company can raise prices to meet the revenue cap without having to connect new customers.[145]

134. Finally, ATCO Gas and AltaGas pointed out that their respective revenue-per-customer cap plans do not contemplate an adjustment if the forecast PBR revenue or consumption per customer deviates from the actual values. However, the two PBR plans differ with regard to their treatment of forecast customer growth. ATCO Gas proposed that the forecast of the average number of customers be reconciled with the actual number of customers when it becomes available, while AltaGas' plan does not provide for such a true-up.[146]

Commission findings

135. A price cap plan sets customer rates in accordance with the established I-X index, regardless of the company's actual costs and the amount of energy transported. A revenue cap also employs an I-X index. However, under the latter approach, it is the revenue of the company and not its rates that is adjusted by the I-X index. Consequently, customer rates may fluctuate so long as revenue does not exceed the revenue cap.

136. The PBR plans proposed by ATCO Gas and AltaGas demonstrate that under a revenue-per-customer cap plan, customer rates are calculated on a class by class basis by dividing the revenue-per-customer cap derived from the formula by the forecast use per customer for the upcoming year. For example, if the actual billing determinants from the previous year were used for calculating customer rates in the upcoming year, the declining use per customer would lead to a systematic under-recovery of revenues by the companies. Under the proposed revenue-per-customer cap plans, customer rates will go down if the company forecasts an increase in energy consumption per customer in the upcoming year. Likewise, customer rates will go up if a decrease in energy consumption per customer is projected for the coming year. In either case, a company's revenue per customer will not exceed the value established by the PBR formula.

137. Under a price cap plan, the company ordinarily bears the risk of changes in energy volumes delivered, while under a revenue cap plan the company is largely protected from volumetric risk. Parties to this proceeding pointed out that the volumetric risk may become too great to bear when there is an expected continuing decline in use per customer.[147] In this circumstance, the use of a price cap may be problematic as it may expose the company to significant reductions in revenues resulting from declines in use per customer.

138. Both ATCO Gas and AltaGas indicated that, despite the overall sales growth, they are experiencing a continuing decline in use per customer, averaging approximately 1.5 per cent per year.[148] This rate of decline in average customer use is forecast to continue into the future. Furthermore, the companies noted that overall customer growth and increased consumption by some existing customers does not completely offset overall declines in the average use per customer.[149] The Commission accepts the average usage per customer decline rates forecasted by ATCO Gas and AltaGas and accepts the position that a price cap plan would result in significant

145 Exhibit 243.01, AUI-CCA-2(g) and (h).
146 Exhibit 99.01, ATCO Gas application, paragraphs 43-44; Transcript, Volume 8, page 1370, line 25 to page 1371, line 6 (AltaGas).
147 Exhibit 632, ATCO Gas argument, paragraphs 141-143 and Exhibit 628, AltaGas argument, page 35.
148 Transcript, Volume 3, page 553, lines 18-22 and Exhibit 212.02, AUC-ATCOGas-1(c) and (d); Transcript, Volume 8, pages 1356-1357 and Exhibit 248.03, AUC-AltaGas-8(c) and (e).
149 Transcript, Volume 3, page 554, lines 12-15 and Volume 8, page 1356, lines 2-9.

revenue reductions under existing rate structures due to declining gas usage if such declines in revenue were not otherwise adjusted for.

139. The Commission also agrees with AltaGas' argument that the revenue-per-customer cap approach to PBR is consistent with the underlying cost structure of gas distribution utilities. A large proportion of gas distributors' costs are fixed, while a significant amount of these costs is recovered through variable charges. As a result, unexpected changes in use per customer may lead to significant variations in the revenues of gas distribution companies that are not offset by cost changes. By focusing on revenue per customer as opposed to price per unit of gas delivered, the revenue-per-customer cap PBR plans proposed by ATCO Gas and AltaGas account for the impact of changes in use per customer on the companies' revenues.

140. Given the above, the Commission considers that forecasting use per customer for the upcoming year is warranted in this case since it accounts for the declining use per customer.

141. The Commission agrees with the parties to this proceeding that the incentive properties of both price cap and revenue-per-customer cap plans are largely the same. Both types of plans rely on an I-X indexing mechanism that decouples revenues from the costs of service, thus creating efficiency incentives. Additionally, both price cap and revenue-per-customer cap formulas use customer growth as a driver for revenue growth, thus providing incentives to continue connecting new customers. The Commission also acknowledges that, by making companies indifferent to volume changes, revenue-per-customer caps provide incentives to promote DSM plans.[150]

142. The Commission also accepts NERA's proposition that diminished service quality can be more of a concern under revenue caps than price caps. However, the Commission considers that concerns with respect to the maintenance of service quality can be addressed through service quality monitoring and reporting measures under both price cap and revenue cap PBR plans. Service quality is discussed in Section 14 of this decision.

143. Overall, the Commission agrees with ATCO Gas and AltaGas that the revenue-per-customer cap approach to PBR adequately addresses the issues associated with declining usage per customer without decreasing the intended efficiency incentives of performance-based regulation. The Commission observes that Calgary and the CCA supported the use of revenue-per-customer cap plans for ATCO Gas and AltaGas.[151]

144. Regarding the issue of a true-up to the actual number of customers, as proposed by ATCO Gas, the Commission notes that the focus of the PBR plans proposed by the gas distribution companies in this proceeding is on indexing the revenue per customer for each customer class, not the overall revenue of a company. Accordingly, the correct measure to true up, if any, is the forecast use per customer.

150 The commission has denied certain types of demand side management programs proposed by the gas distribution companies as being inconsistent with the legislative framework. For example see, Decision 2011-450: ATCO Gas (A Division of ATCO Gas and Pipelines Ltd.), 2011-2012 General Rate Application Phase I, Application No. 1606822, Proceeding ID No. 969, December 5, 2011, paragraph 683 and Decision 2012-091: AltaGas Utilities Inc., 2010-2012 General Rate Application Phase I, Application No. 1606694, Proceeding ID No. 904, April 9, 2012, paragraph 625.

151 Exhibit 329, Calgary argument, page 37; Exhibit 636, CCA argument, page 2 and Transcript, Volume 13, page 2534, lines 13-17 (Lowry).

145. In the interest of regulatory efficiency, the Commission considers that no true up for the actual weather normalized use per customer is required. The Commission directs the gas companies to use the actual average change in weather normalized use per customer (per class) for the preceding three years as their forecast percentage change in weather normalized use per customer for the upcoming year. This percentage change is to be applied to weather normalized use per customer (actual and projected per class) for the current year to determine the forecast for the upcoming year. The Commission is satisfied that the rate of change in weather normalized use per customer over the preceding three year period will result in a reasonable forecast of weather normalized use per customer for the upcoming year.

146. With respect to the PBR plans of ATCO Electric, EPCOR and Fortis, these companies indicated that a declining use per customer or other types of volumetric risk are not an issue for them.[152] As well, Dr. Lowry pointed out that North American electric utilities often experience modest growth in average use by small volume customers when large DSM programs are not underway in their service territories.[153] Consequently, the Commission has no concerns with the use of a price cap approach in the PBR plans for the electric distribution companies.

5 I factor

5.1 Characteristics of an I factor

147. The inflation factor, also referred to as an I factor or an input price index, is the component of a price cap or revenue cap PBR (performance-based regulation) plan that reflects the expected changes in the prices of inputs that the companies use. As the companies' experts explained, a PBR formula should be designed to produce rates that reflect inflationary pressures on input prices that a company is expected to experience from year to year during the term of the plan.[154] The purpose of the inflation factor is to pass on to customers the increases in the costs of goods and services purchased by the company (for example, cost of the materials and supplies, salaries of the company's staff, etc.*)* that are driven by macro-economic forces and are beyond the control of the company's management.[155]

148. The UCA noted that, by setting an automatic adjustment for the company's cost changes, an input price index obviates the need to hold frequent cost of service proceedings. The UCA pointed out that, in effect, the I factor mirrors the process of reviewing a company's costs and adjusting rates on a prudency basis, in effect using the selected inflation measure as a prudency test.[156]

149. In their respective PBR submissions, parties outlined a number of considerations for choosing the relevant I factor. Specifically, parties proposed the following selection criteria for establishing an inflation index:[157]

152 Transcript, Volume 3, pages 557-559; Exhibit 103.05, Cicchetti evidence, page 14.
153 Exhibit 307.01, PEG evidence, page 17.
154 Exhibit 110.01, Christensen Associates evidence, paragraph 29; Exhibit 98.02, Carpenter evidence, page 15.
155 Exhibit 100.02, prepared testimony of Julia Frayer, page 33.
156 Exhibit 299.02, Cronin and Motluk UCA evidence, page 182, A87.
157 Exhibit 631.01, ATCO Electric argument, paragraph 38; Exhibit 632.01, ATCO Gas argument, paragraph 34; Exhibit 628.01, AltaGas argument, pages 11-12; Exhibit 633.01, Fortis argument, paragraph 63; Exhibit 636.01, CCA argument, paragraph 48.

- The I factor must be indicative of the change in input prices that the company expects to experience over the term of the PBR plan.
- The inflation index must be published by a reputable, independent agency and made readily available on at least an annual basis.
- The I factor should be transparent, simple to calculate and easy to understand.
- The selected I factor should not be overly volatile.
- The I factor should reflect a broad measure of inflation rather than the experience of the specific company to which the PBR plan is to apply, so that the company cannot significantly affect the index.

150. In addition to these criteria, Dr. Ryan on behalf of EPCOR indicated that, in conducting his analysis and recommending an inflation index, he considered the Commission's findings in Decision 2009-035. In particular, EPCOR's expert recommended using an input-based index, thus avoiding the need for making adjustments to the productivity factor, which would be the case if an output-based price index were used.[158] This recommendation was also supported by the UCA.[159]

151. Additionally, in setting out his proposed criteria, Dr. Ryan recommended that if the inflation factor was composed of different component indexes, the weighting of these should be fixed rather than vary year to year, so that the company's incentives are not influenced by relative rates of inflation in the component indexes.[160]

152. The CCA pointed out that the I factor selection criteria are often in conflict and that there is "considerable art in developing an index that sensibly balances simplicity and accuracy."[161]

Commission findings

153. The I factor provides a mechanism to adjust the companies' prices[162] (in the case of a price cap plan) or revenues (in the case of a revenue-per-customer cap plan) year over year to reflect changes in the prices of inputs that the companies use.

154. As the ATCO companies pointed out in their arguments, a PBR plan should provide incentives for the company to undertake efficiency improvements to manage and minimize the costs that are within its control. However, changes in a company's input prices due to inflation are not within its ability to control, although the company may be able to use those inputs more efficiently than its competitors.[163] In competitive markets, when faced with a universal, economy-wide increase in input prices (such as an increase in salaries and wages, higher fuel prices, etc.), companies are often left with no choice but to pass on these higher costs to consumers. Similarly, when the prices of inputs go down, competition in the market forces the companies to lower their prices. The I factor in the PBR plans is intended to mimic this characteristic of competitive markets.

[158] Exhibit 103.04, Dr. Ryan evidence, paragraph 8.
[159] Exhibit 634.02, UCA argument, paragraph 76.
[160] Exhibit 103.04, Dr. Ryan evidence, paragraph 8.
[161] Exhibit 636, CCA argument, paragraph 49.
[162] Utility output prices are most commonly referred to as rates. In the context of a price cap plan they are referred to as prices.
[163] Exhibit 631, ATCO Electric argument, paragraph 37.

155. All parties agreed that the selected I factor should be indicative of the change in input prices that the companies are expected to experience, be transparent, simple to calculate and easy to understand. In addition, parties recommended that the inflation factor should not be overly volatile, must be published on a regular basis by a reputable independent agency and should not be overly influenced by the company itself. The Commission agrees.

156. The choice between input and output inflation indexes, the use of a single index or a composite I factor consisting of multiple indexes and the weights to be assigned to the elements of a composite I factor are discussed in the subsequent sections of this decision.

5.2 Selecting an I factor

5.2.1 The rationale behind a composite I factor

157. In Decision 2009-035, dealing with ENMAX's 2007-2016 FBR (formula-based ratemaking) application, the Commission approved a composite I factor that includes the distribution construction price index as measured by the Canadian Electric Utility Construction Price Index (EUCPI) and the Alberta Average Hourly Earnings (AHE) index with a 50:50 fixed weighting throughout the PBR term.[164]

158. The companies argued that, in general, no single measure of inflation can explain all the cost trends facing a utility, and they maintained that greater accuracy can be achieved by constructing a composite index composed of published indexes, weighted according to the average relationship among the company's various inputs.

159. Specifically, AltaGas' experts explained that a utility primarily purchases two types of inputs, employee time and goods and services from other firms. The prices that a company in Alberta must pay for these inputs will be affected primarily by economic conditions within the province of Alberta.[165] This position was supported by the other companies with each proposing that their respective I factors consist of two inflation indexes, one reflecting labour cost and the other reflecting the cost of non-labour items. Such a blended I factor would generally be calculated each year using the following weighted-average formula:

$$\textit{I factor} = w_l * \textit{Labour Price Index} + w_n * \textit{Other Costs Price Index}$$

160. For labour costs, the companies preferred to use either Average Hourly Earnings (AHE) or Average Weekly Earnings (AWE) for Alberta. For non-labour costs, the companies preferred to use either the EUCPI adjusted for Alberta inflation or the Alberta Consumer Price Index (CPI). These sub-indexes would be weighted based on the companies' historical proportions of labour (w_l) and non-labour (w_n) costs. The following table summarizes the proposed I factors as outlined in the electric distribution companies' respective PBR applications:

164 Decision 2009-035, paragraphs 144 and 149.
165 Exhibit 110.01, Christensen Associates evidence, paragraph 30.

Table 5-1 Summary of electric distribution companies' I factor proposals

	ENMAX[166] (distribution)	ATCO Electric (distribution)	Fortis	EPCOR (distribution)
Labour costs	Alberta AHE	Alberta AWE	Alberta AHE	Alberta AHE
Non-labour costs	EUCPI (no adjustment)	EUCPI (adjusted for Alberta)	EUCPI (adjusted for Alberta)	Alberta CPI
Weights (labour/non-labour)	50:50	65:35	61:39	80:20

161. Table 5-2 below presents the I factors proposed by the gas distribution companies in their respective PBR plans:

Table 5-2 Summary of gas distribution companies' I factor proposals

	ATCO Gas	AltaGas
Labour Costs	Alberta AWE	Alberta AWE
Other Costs	Alberta CPI	Alberta CPI
Weights (labour/non-labour)	57:43	57:43

162. The UCA supported the use of a composite I factor and indicated that the Commission should use the input price index approved for ENMAX in Decision 2009-035 for all the companies in this proceeding.[167]

163. The CCA also acknowledged the need for an inflation measure that reflects the "special inflationary conditions that sometimes occur in Alberta." The CCA pointed out that inflation can be much more rapid in Alberta than in Canada as a whole in some periods (for example, 2006 to 2008) and appreciably lower in other periods (2009 to 2010), since the province's economy can experience "booms and busts" because it is largely influenced by the production of price-volatile commodities.[168]

164. The CCA recommended that the I factor consist of either a single macroeconomic measure of Alberta price inflation or an appropriately designed custom index of Alberta utility input price inflation. With respect to macroeconomic inflation measures, the CCA recommended using either the Alberta gross domestic product implicit price index for final domestic demand (GDP-IPI-FDD) or the Alberta CPI.

165. PEG on behalf of the CCA, developed an index that tracks the prices of three categories of input costs: labour, materials and services, and capital. Specifically, PEG recommended using either CPI or GDP-IPI-FDD for Alberta as the proxy for the materials and supplies input price index and the Alberta AHE or AWE for the labour price index. For the capital cost category, PEG constructed this element as the product of a rate of return on capital (set initially at the weighted average cost of capital established for the subject utility in its most recent rate case)

166 As approved in Decision 2009-035. ENMAX was included in this table for comparison purposes.
167 Exhibit 634.02, UCA argument, paragraph 73.
168 Exhibit 636, CCA argument, paragraph 44.

and a triangularized weighted average of past values of the EUCPI, with an adjustment to reflect Alberta construction market conditions.[169]

166. Calgary also recommended using the Alberta GDP-IPI-FDD index and indicated that it did not support the adoption of a composite I factor consisting of several weighted indexes because such an inflation measure would not be consistent with the simplicity principle.[170]

Commission findings

167. A number of parties pointed out that, because the Alberta economy is influenced by the production of price-volatile commodities such as oil and natural gas, it can experience wider swings in economic activity than the rest of the Canadian economy. As a result, inflation in the province can be quite different from inflation in the Canadian economy as a whole.

168. The companies also highlighted the fact that the presence of large scale capital-intensive oil and gas activity in Alberta leads to strong competition for labour resources, especially those involved in technical and engineering services, as well as capital-intensive projects. Accordingly, the companies were particularly concerned that the I factor be able to capture the effect of the tight labour market in Alberta.[171] As Dr. Cicchetti on behalf of EPCOR explained:

> But high oil prices and high gas prices, although those are now falling, but high oil prices at least have the effect of making the demand in the job market tighter, and the demand for people who are engineers of whatever kind who can be employed by electric distribution companies is tighter.[172]

169. The Commission agrees with these observations. Because of the relatively tight labour market in Alberta, salaries and wages have been rising faster than the national average during petroleum industry booms and have declined more rapidly or risen less quickly during economic slowdowns, as compared to the rest of Canada. Therefore, the Commission will include an Alberta-specific labour inflation component in the I factor of the companies' PBR plans to reflect labour inflation in the province.

170. The Commission agrees with the companies that all-encompassing macroeconomic inflation measures, such as Alberta GDP-IPI-FDD or Alberta CPI proposed by the CCA and Calgary, when used as the only measure of inflation, do not reflect the input price inflation faced by the companies. As ATCO Gas pointed out, using a single macroeconomic index for the I factor may result in a significant revenue shortfall due to the under-recovery of its labour-related costs.[173] Furthermore, the CCA agreed that both CPI and GDP-IPI-FDD in this context are output price indexes, thus requiring adjustments to the productivity measure (in this case a TFP (total factor productivity) study) in determining an X factor as explained in Section 6.4.1 below.[174] In the Commission's view, the need for such an adjustment more than offsets any simplicity and transparency benefits of using a single macroeconomic inflation measure.

169 Exhibit 307.01, PEG evidence, pages 52-54 and Exhibit 376.18, ATCO-CCA-63 attachment.
170 Exhibit 629.01, Calgary argument, page 22.
171 Transcript, Volume 7, page 1291, lines 13-16, Volume 11, page 2137, line 24 to page 2138, line 1.
172 Transcript, Volume 11, page 2061, lines 19-24.
173 Exhibit 632, ATCO Gas argument, paragraph 49.
174 Exhibit 636, CCA argument, paragraph 51.

171. Accordingly, for the reasons above the Commission finds that the use of a composite I factor in the PBR plans of Alberta utilities is warranted.

172. The Commission considers that the composite I factors proposed by the companies generally conform to the input price index selection criteria outlined in Section 5.1. The proposed sub-indexes for labour and non-labour costs are published by Statistics Canada on a regular basis and, as explained in further sections of this decision, do not require any subjective modifications. The Commission considers that these indexes are sufficiently broad-based to avoid potential concerns about the activities of the companies significantly influencing these measures.

173. In addition, as explained in Section 6.4.1 below, since all the components of the I factors proposed by the companies can be considered input price indexes for the Alberta electric and gas distribution companies, using such a composite I factor does not require an adjustment to TFP in determining an X factor in order to account for an input price differential and a productivity differential.

174. With respect to the customized index for labour, capital and materials proposed by the CCA, the Commission notes that a similar index was proposed by the UCA in the ENMAX FBR proceeding, as outlined in Decision 2009-035. In that decision, it was noted that this type of I factor was more data intensive and more complex than the Commission considered desirable for the purposes of a PBR plan.[175] Indeed, in this proceeding, the CCA pointed out that the selection of an inflation measure for a PBR plan is difficult because greater accuracy comes at the cost of greater complexity.[176] ATCO Gas pointed out that the CCA's index needed a 15 page spreadsheet with a number of significant, complex calculations.[177] During the hearing, Dr. Lowry concurred that the calculation of the proposed customized index would likely require a Ph.D.'s expertise.[178] As such, the Commission considers that the customized index proposed by the CCA suffers from the same data intensity and complexity drawbacks as did the UCA's proposal for ENMAX. Furthermore, similar to the proposed I factors of ATCO Gas and Fortis, the CCA's customized inflation factor involves a modification to EUCPI to attempt to better reflect Alberta inflation. The Commission discusses the shortcomings of such adjustments in Section 5.2.3 below.

175. Finally, the CCA contended that the added complexity of a customized inflation index was warranted because it better tracked input price inflation. However, when the CCA compared its proposed customized I factor to a GDP-IPI-FDD index, the results were within 0.01 percentage points of each other over the 2001 to 2010 period.[179]

176. In light of the above considerations, the Commission is not persuaded that the customized index proposed by the CCA is superior to the types of I factors proposed by the companies.

177. Similar to the findings in Decision 2009-035, the Commission recognizes that the blended I factors proposed by the companies do not specifically account for changes in the cost

[175] Decision 2009-035, paragraph 139.
[176] Exhibit 636, CCA argument, paragraph 49.
[177] Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 164.
[178] Transcript, Volume 13, page 2587, lines 1-6.
[179] Exhibit 372.01, AUC-CCA-20(c).

of capital.[180] Although there was some debate at the proceeding as to whether financing rates in the economy as a whole may be reflected sufficiently in the rate of inflation, it is the Commission's view that financing rates are a function of interest rates in the economy as a whole, which themselves are ultimately reflected in the rate of inflation. As Dr. Lowry stated:

> But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta…[181]

178. On the issue of whether changes in the cost of capital are reflected in the selected I factor, AltaGas stated in its rebuttal evidence:

> The inflation factor, like the X-factor, is designed to mirror the way prices change in a competitive economy. In a competitive economy, the price of capital inputs is determined by the real rate of return on assets, their rate of economic depreciation and the price of acquiring and installing capital. In much of productivity research, including previous productivity research conducted by us [Christensen Associates Energy Consulting] and PEG, the real rate of return has been computed using the current year's nominal rate of return and the rate of inflation in recent years. This produced significant year-over-year volatility in the real rate of return, which, in turn, led to significant year-over-year volatility in the price of capital services. With this volatility, researchers were unable to determine the trend rates of price inflation with any degree of accuracy. In recent years, researchers have noted the real rate of return fluctuates around a constant value and have taken the approach of using a fixed, real rate of return when computing capital price inflation. Fixing the real rate of return at a constant value implies the price of capital services moves in proportion to the price of acquiring and installing that capital. Thus, the relatively straight forward way of computing the inflation factor proposed by AUI is also theoretically sound.[182]

179. The theory supported by the AltaGas experts implies that changes in the cost of capital (both debt and equity) are sufficiently reflected in the company's selected inflation measure. AltaGas' proposed I factor is similar to what the Commission has adopted.

180. Accordingly, the Commission considers that a composite I factor consisting of two broad-based indexes for labour and non-labour costs captures changes in the cost of capital (both debt and equity). In addition, including a separate adjustment for the company's actual cost of capital in the I factor would require accounting for other cost items such as rate base and depreciation to determine the weighting of the capital cost component of such an I factor. In Decision 2009-035, the Commission expressed its concerns with an I factor that appeared to be an effort to move closer to an inflation index that tracked the experience of a specific company to which the PBR plan would apply rather than a broader industry inflation measure.[183] The more the selected inflation measure tracks the actual performance of an individual company, the more it resembles cost of service regulation and the more the incentive properties of PBR are

[180] Decision 2009-035, paragraphs 139-140.
[181] Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.
[182] Exhibit 477, Christensen Associates rebuttal evidence filed on behalf of AltaGas, paragraph 56.
[183] Decision 2009-035, paragraph 141.

diminished. For all these reasons, the Commission finds that no adjustments for company-specific capital costs should be incorporated in the I factor.

181. Overall, the Commission is satisfied that a composite I factor consisting of two indexes (one for labour and the other for non-labour costs), represents a reasonable balance between the need for transparency and the need for accuracy in establishing an input price inflation measure for the Alberta electric and gas distribution companies.

182. The individual components of a composite I factor are discussed below.

5.2.2 Labour input price indexes (AHE vs. AWE)

183. Some of the companies proposed using the Alberta AHE as the labour price index component of their I factors, while others preferred using the Alberta AWE instead. Both of these indexes are published by Statistics Canada. However, since the agency produces many variations of the AWE and AHE indexes, careful attention must be paid to the definition of a particular inflation measure when evaluating it.

184. In their respective PBR applications, Fortis and EPCOR proposed using the AHE index, defined as average hourly earnings for salaried employees (paid a fixed salary), including overtime and unadjusted for seasonal variation, which is published for selected industries classified using the North American Industry Classification System (NAICS).[184] ATCO Electric, ATCO Gas and AltaGas proposed to use the AWE, defined as average weekly earnings, including overtime and seasonally adjusted for all employees in selected industries classified using the NAICS.[185]

185. The broadest measure for both AHE and AWE indexes is the aggregate index or industrial aggregate, which includes all NAICS industries (including utilities), except for those industries that are unclassified. As Dr. Ryan explained in his evidence, it is preferable to use either AHE or AWE for the industrial aggregate, since the weights of the individual industries in these two labour inflation indexes are not known. Further, an Alberta AHE or AWE for the utilities sector would be influenced by the companies.[186] Consequently, all the companies proposed using the AHE or AWE labour input price indexes at the industrial aggregate level.

186. In response to the Commission's information request (IR) as to whether there would be material differences in the inflation rates used for the PBR formulas if AHE or AWE were employed to calculate an I factor, the companies agreed that even though the two inflation measures may differ from each other substantially in a single year, over an extended period, both measures of labour costs increase at a similar rate. For example, Fortis pointed out that, over the period from 1999 to 2009, Alberta AHE grew by an average of 3.7 per cent annually, while Alberta AWE grew by an average of 3.8 per cent annually.[187] A similar conclusion was reached by Dr. Ryan.[188] Based on the inflation data filed by the parties, the Commission has produced the following table which compares the Alberta AHE and AWE growth rates over the period of 1999 to 2010:

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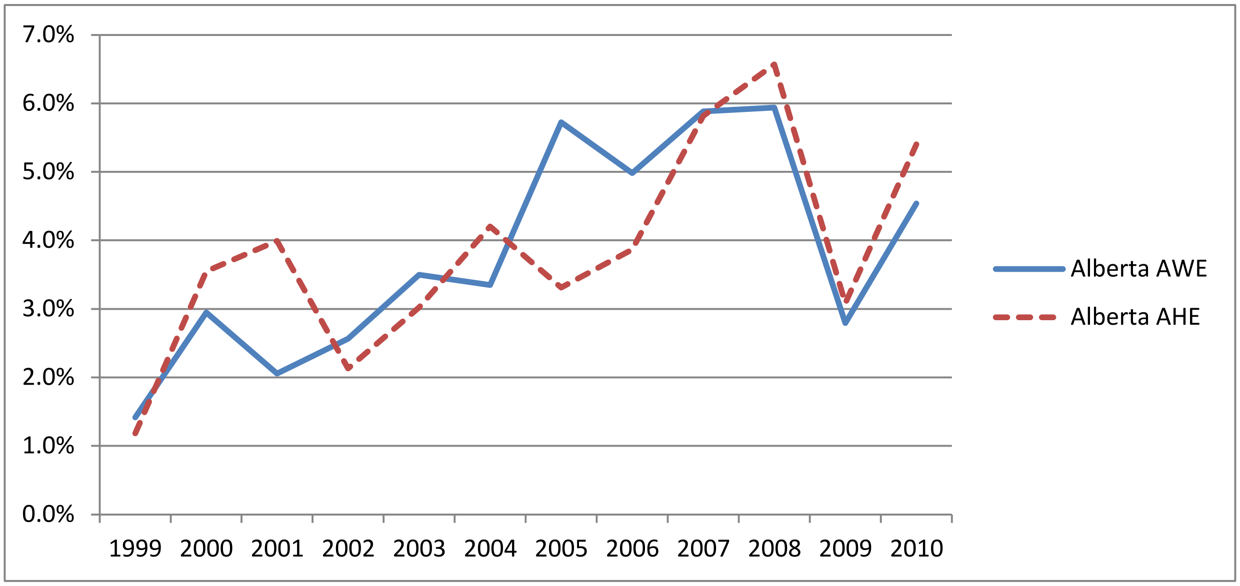
184 Statistics Canada Table 281-0036, data vector V1808689.
185 Statistics Canada Table 281-0028, data vector V1597350.
186 Exhibit 103.04, Dr. Ryan evidence, paragraph 13.
187 Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
188 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.

Table 5-3 Alberta AHE and Alberta AWE, 1999-2010 (in per cent)[189]



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Average 1999-2010
Alberta AWE	1.4	2.9	2.1	2.6	3.5	3.4	5.7	5.0	5.9	5.9	2.8	4.5	**3.8%**
Alberta AHE	1.2	3.6	4.0	2.1	3.0	4.2	3.3	3.9	5.8	6.6	3.1	5.4	**3.8%**

187. However, the companies restated their preferences for the labour index set out in their PBR applications. ATCO Electric and ATCO Gas argued that the AWE index more accurately represents their labour input costs as compared to the AHE index and therefore better meets AUC PBR Principle 4.[190] Fortis proposed to use the Alberta AHE for the labour component of the I factor, arguing that approximately 75 per cent of its employee compensation is based on an hourly rate of pay.[191] AltaGas argued that, because many of its employees and its contractors' employees are wage employees, it preferred to use the AWE index, which takes both hourly and salary compensation into account.[192] EPCOR concluded that, for the purpose of calculating an I factor to use in the PBR formulas, it is immaterial which measure is used.[193]

Commission findings

188. As EPCOR explained, both the AWE and AHE indexes are obtained from the same Statistics Canada survey[194] and therefore are based on the same underlying data. Table 5-3 above demonstrates that, over the period from 1999 to 2010, the two series yielded essentially the same overall average inflation rate.

[189] For AWE, see Exhibit 540.02. For AHE, see Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.
[190] Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.
[191] Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
[192] Exhibit 248.02, AUC-ALLUTILITIES-AUI-4.
[193] Exhibit 233.01, AUC-ALLUTILITIES-EDTI-4.
[194] Survey of Employment, Payrolls and Hours (SEPH).

189. The Commission observes that there is no significant difference between the Alberta AWE and Alberta AHE over an extended period of time at the industrial aggregate level and accordingly, for the purposes of establishing an I factor, either measure can be adopted.

190. Parties to this proceeding pointed out that, based on the Statistics Canada definitions of the two indexes, the main difference is that the AWE index includes both salaried employees and those paid an hourly wage while the AHE index referenced in this proceeding includes salaried employees only. In that regard, the Commission agrees with Fortis' explanation that year-to-year differences between the two measures can be explained by the fact that the adjustment of labour utilization in response to variations in economic activity are made through the number of hours worked in the short term, while salaries are slower to adjust to economic booms and slowdowns.[195]

191. In the Commission's view, using the AWE index which includes both salaried employees and those paid an hourly wage would capture the inflationary trends in labour costs more quickly than an index which includes salaried employees only. Further, given that the AWE reflects variations in economic activity sooner than the AHE, using the AWE in the composite I factor would mitigate somewhat the effect of the inflation lag resulting from using the actual inflation from the preceding 12-month period for the upcoming year's I factor, as further discussed in Section 5.3 below. In addition, the Commission observes that unlike the AWE index (from Statistics Canada Table 281-0028) that is published monthly, the AHE index (from Statistics Canada Table 281-0036) proposed by Fortis and EPCOR is published on an annual basis. As such, using the Alberta AHE index for January 1st rate changes will effectively result in a 24-month lag between the I factor used in the PBR plan and the actual labour inflation experienced by the provincial economy in any given year.

192. The other difference between the two indexes is that the proposed AWE index is seasonally adjusted, while the AHE is not. Taking into account the fact that the purpose of the seasonal adjustment is to adjust for patterns that occur within a year, the Commission agrees with the ATCO companies' view[196] that the adjustment for seasonal variation is not relevant in this case, since the companies will be using the inflation indexes over a 12-month period. Accordingly, seasonal adjustment is not a reason to choose one index over the other.

193. Finally, the Commission is satisfied that the Alberta AWE index, at the industrial aggregate level which includes all industries in the Alberta economy, is sufficiently broad-based to avoid potential concerns about the companies' actual experience significantly influencing these measures.

194. For all these reasons, the Commission considers that using the Alberta AWE index from Statistics Canada Table 281-0028, data vector V1597350 as a labour cost component of the I factor for the Alberta companies provides a reasonable overall reflection of labour price changes.

5.2.3 Non-labour input price indexes

195. In Decision 2009-035, the Commission approved the use of EUCPI as a component of ENMAX's composite I Factor. Having analyzed its recent experience under the PBR plan,

[195] Exhibit 219.02, AUC-ALLUTILITIES-FAI-4.
[196] Exhibit 203.01, AUC-ALLUTILITIES-AE-4 and Exhibit 204.02, AUC-ALLUTILITIES-AG-4.

ENMAX noted that, because the EUCPI portion of its I factor is a Canada-wide index, it may not be sufficiently aligned with actual cost increases faced by an electric distribution company in Alberta.[197] The CCA also objected to the use of the unadjusted national EUCPI index in the PBR plans of the Alberta electric distribution companies.[198]

196. EPCOR, ATCO Gas and AltaGas proposed to use the all items Alberta CPI for the non-labour component of their I factors.[199] The CPI for all items is the broadest measure of the consumer price inflation, and reflects the prices of a wide variety goods and services in the economy. EPCOR, ATCO Gas and AltaGas argued that the Alberta CPI is perhaps the best index to reflect changes in their non-labour input prices. Furthermore, these companies indicated that they have traditionally used, and the Commission has adopted, the Alberta CPI in the past to forecast general supply-related costs in their cost of service rate applications. In addition, AltaGas noted that the use of the Alberta CPI reflected the fact that most of its non-labour inputs are sourced within the province.[200]

197. The proponents of the Alberta CPI generally agreed that this index may be regarded as an output rather than an input-based price index and, as such, could be influenced by the economy-wide productivity. However, as AltaGas observed, economy-wide outputs also serve as inputs in the form of goods and services purchased by companies. Additionally, Dr. Ryan, Dr. Carpenter and Dr. Schoech explained that, in the context of a composite I factor, the Alberta CPI will be used only to track changes in the prices of their non-labour inputs. Accordingly, the companies generally agreed that the Alberta CPI could be regarded as a proxy for an input price index for the purposes of their composite I factors, obviating the need for an adjustment to the TFP to calculate the X factor.[201]

198. In turn, ATCO Electric and Fortis proposed using the EUCPI for distribution systems as a price index for their non-labour input costs.[202] In her evidence, Ms. Frayer pointed out that, since the EUCPI is a national indicator, an adjustment factor was necessary to capture the differences in inflationary trends between Alberta and the Canadian average. To develop such an adjustment factor, Ms. Frayer proposed using the ratio of the Alberta to Canada GDP implicit price index (GDP-IPI) as a proxy for the inflation differential between the province and the rest of Canada.

199. After comparing the 10-year average of Alberta and Canada GDP-IPI trends for the period of 2000 to 2009, Fortis' expert recommended an adjustment factor of 29 per cent (or 1.29) per year to the national EUCPI to reflect Alberta inflation.[203] Using similar logic, and by taking a mid-point of the 10-year (2000 to 2009) and 15-year (1995 to 2009) ratios of Alberta to Canada GDP-IPI, ATCO Electric recommended an adjustment to the national EUCPI of 23 per cent (or 1.23) per year.[204]

200. The CCA supported an adjustment to EUCPI to account for the difference between Alberta and Canada inflation; however, it did not agree with ATCO Electric's and Fortis'

[197] Exhibit 297.01, ENMAX evidence, page 15.
[198] Exhibit 636, CCA argument, paragraph 46.
[199] Monthly Alberta CPI is reported in Statistics Canada Table 326-0020, data vector V41692327.
[200] Exhibit 628, AltaGas argument, page 16.
[201] Transcript, Volume 4, page 612, line 25 to page 614, line 10; Volume 8, page 1415, line 12 to page 1416, line 3. See also Exhibit 103.04, Ryan evidence, paragraph 32.
[202] Statistics Canada Table 327-0011, data vector V735224.
[203] Exhibit 100.02, prepared testimony of Julia Frayer, pages 41-43.
[204] Exhibit 98.01, ATCO Electric application, Schedule 3-3.

proposal for an adjustment. Specifically, the CCA expressed its opinion that GDP-IPI is an improper basis for comparing inflation in Alberta and Canada as a whole because price inflation in Alberta is especially sensitive to the prices of oil and gas exports, which are volatile. In PEG's view, the GDP-IPI-FDD index was more suitable for this purpose because it is less volatile that GDP-IPI index.[205] In addition, the CCA argued that, by using the most recent period of 10 to 15 years to compare price trends and adjust the Alberta EUCPI, the companies would lock in the favourable inflation differential observed in that period.[206]

201. The UCA stated that the EUCPI is more likely to represent the input capital costs of the Alberta companies because the CPI is an output measure for consumers and is wholly inappropriate for determining the I factor for the companies.[207] The UCA also contended that the EUCPI is a relevant index for gas distribution companies as well because many materials and services used in capital construction for gas distribution companies are similar to those used by electric distribution companies.[208]

202. Calgary also objected to the use of the Alberta CPI and observed that the cost components included in this index have little relevance to the cost of gas and electric distribution activities. Further, in Calgary's view, using Alberta CPI in conjunction with AWE could lead to double counting of labour costs.[209]

Commission findings

203. The Commission recognizes that using the EUCPI presents a number of problems. First, the EUCPI is a national indicator. Statistics Canada does not produce an Alberta-specific version of this index. Therefore, an adjustment to the EUCPI to account for Alberta-specific inflation must be considered. However, making such an adjustment introduces issues associated with comparing inflation in Alberta to Canada. These include whether to use levels or growth rates as the best indicator of the difference in inflation rates, whether to keep an adjustment constant or permit it to change during the PBR term and selecting an appropriate time period for such a comparison, among others.[210]

204. The ATCO companies, when commenting on an adjustment to the EUCPI proposed by PEG, submitted that such a complicated customization of the EUCPI would add complexity and confusion to a PBR plan.[211] In the Commission's view, adjusting the EUCPI introduces a high degree of subjectivity and makes the resulting I factor less transparent and more difficult to understand.

205. Additionally, as ATCO Gas and AltaGas pointed out, no construction price index similar to the EUCPI is available for gas distribution companies. The UCA contended that the EUCPI is relevant for gas companies. However, as the gas companies submitted in their arguments, it is not clear why an index covering electric distribution capital relating to substations, wires, conductors and transformers is applicable to gas distribution companies with capital costs

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205 Exhibit 372.01, AUC-CCA-19(c).
206 Exhibit 372.01, AUC-CCA-19(c).
207 Exhibit 634.02, UCA argument, paragraph 81.
208 Exhibit 361.02, AUC-UCA-10.
209 Exhibit 629, Calgary argument, pages 21-22.
210 For more discussion on this issue, see Exhibit 226.01, AUC-FAI-4 and Exhibit 372.01, AUC-CCA-19.
211 Exhibit 631, ATCO Electric argument, paragraph 50 and Exhibit 632, ATCO Gas argument, paragraph 53.

relating to pipe, distribution compressors, regulators and meter stations.[212] The Commission agrees that the EUCPI should not be used as part of an I factor in a PBR plan for the gas distribution companies.

206. In the previous section of this decision the Commission agreed that the substantial influence of the oil and gas sectors on inflationary pressures in Alberta can lead to substantially different inflationary pressures than in the Canadian economy as a whole with respect to labour costs. The Commission considers that the same is true for non-labour costs. Accordingly, the Commission finds that it would be more accurate to use an Alberta measure of non-labour input price inflation.

207. If EUCPI without adjustment to reflect the Alberta environment is undesirable given the differences in inflationary pressure between Alberta and Canada as a whole, and if adjusting EUCPI to Alberta is problematic, then the Commission must consider other available indexes to adjust non-labour costs for inflation.

208. Dr. Lowry recommended using the Alberta GDP-IPI-FDD as the inflation measure for materials and services, since this index is less volatile than the Alberta CPI. However, Dr. Lowry discussed the benefits of using the GDP-IPI-FDD in the context of a customized I factor which also includes separate capital and labour components.[213] The Commission dismissed in Section 5.2.1 PEG's customized approach to setting the I factor. It is unclear whether the same benefits would be realized when this index is used for a two part I factor consisting only of labour and non-labour components.

209. Unlike the Alberta GDP-IPI-FDD, the CPI for Alberta is readily available from Statistics Canada on a regular basis and does not require any subjective adjustments or modifications. As a result, this index is easily understood by customers. While it may be argued that the Alberta CPI is less relevant to the electric and gas companies' business when used as the only inflation measure in a PBR plan, the Commission agrees with the proponents of Alberta CPI that it adequately reflects the price changes for the non-labour expenditures of Alberta companies to which it will apply. The Commission notes that the Alberta distribution companies (both gas and electric) have used the Alberta CPI as an escalator index for the non-labour items in their cost of service general tariff applications.[214]

210. The Commission agrees with the companies' experts that, because the CPI is a proxy for changes in the companies' non-labour input prices, it may be considered an input price index for the purposes of calculating a composite I factor, obviating the need for any further adjustments to TFP in deriving an X factor, as discussed in Section 6.4.1 of this decision.

211. Finally, during the hearing, the Commission inquired whether there would be a material difference to the I factors if the Alberta CPI were used instead of the adjusted EUCPI proposed by ATCO Electric and Fortis. The provided undertakings demonstrate that over the recent 10-year period, the Alberta CPI tracks very closely to the proposed adjusted EUCPI.[215]

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212 Exhibit 632, ATCO Gas argument, page 12 and Exhibit 628, AltaGas argument, page 16.

213 Exhibit 307.01, PEG evidence, page 52.

214 Exhibit 472.02, ATCO Gas rebuttal evidence, paragraph 173; Transcript, Volume 4, page 614, lines 17-19 (ATCO Electric); Transcript, Volume 11, page 2137, lines 11-18 (Fortis).

215 Exhibit 540 and Exhibit 592.

212. In light of the above considerations, the Commission is not persuaded that either the Alberta GDP-IPI-FDD or the adjusted EUCPI, with its increased complexity and subjectivity, represent a better alternative to the Alberta CPI. Accordingly, the Commission finds that the all-items Alberta CPI (from Statistics Canada Table 326-0020, data vector V41692327) should be used as a non-labour input price index in the composite I factor in the PBR plans of each of the Alberta gas and electric distribution companies.

5.2.4 Weighting of the I factor components

213. In Decision 2009-035, the Commission approved a 50:50 ratio for the components of the ENMAX's I factor by examining the company's historical cost ratios for capital and operating expenses. For the purpose of the ENMAX's I factor, the EUCPI was used to track changes in capital related costs while the AHE index was used to track changes in all O&M (operating and maintenance) expenses.[216]

214. In this proceeding, the companies have not split their costs into capital-related and O&M components for the purposes of calculating an I factor, but rather they have split them into costs driven by labour inflation and costs driven by non-labour inflation. The companies proposed that the labour and non-labour components of their I factors be weighted based on their historical proportion of labour expenditures in total combined operating and capital expenditures for the (three to five-year) period immediately preceding the PBR term.

215. The companies contended that this proposed weighting better reflects the changes in input prices that they expect to experience over the term of the PBR plan. As the ATCO companies explained:

> All labour, regardless of whether it is for capital or for O&M activities, has [the] same inflationary pressures. All workers employed by ATCO Electric or retained by ATCO Electric through a contractor exist in the same labour market here in Alberta. Labour inflation does not discriminate by whether or not the worker's pay is charged to capital or O&M. Indeed, many of ATCO Electric's staff will work on a capital project one day and an O&M project the next.[217]

216. Likewise, the companies noted that inflationary pressures on non-labour costs were likely to be the same regardless of whether they relate to O&M or capital.[218] As a result, the companies grouped their expenditures into labour costs (primarily consisting of salaries, wages and contract labour), and non labour costs (primarily consisting of materials and services) to arrive at the proportional shares for the components of their respective I factor proposals set out in Table 5-1 and Table 5-2 above.

217. The UCA supported the 50:50 weighting approved for ENMAX in Decision 2009-035 because, in Dr. Cronin and Mr. Motluk's view, this weighting reflects the capital shares in Ontario and other jurisdictions internationally.[219]

218. The CCA submitted that three weighting issues are salient in this proceeding: the denominator in the cost share calculations, the weight assigned to labour, and whether company-

216 Decision 2009-035, paragraph 148.
217 Exhibit 631, ATCO Electric argument, paragraph 47.
218 Exhibit 628, AltaGas argument, page 13 and Exhibit 631, ATCO Electric argument, paragraph 48.
219 Exhibit 634.02, UCA argument, paragraph 87.

specific costs should be used to establish weightings.[220] With respect to the first issue, the CCA did not agree with the companies using the sum of O&M and capital expenditures as the denominator in the calculation of the I factor weights. The CCA indicated that the correct denominator to be used in the composite I factor is the sum of O&M and administration expenses and capital costs, which include depreciation, return on rate base, as well as income and property taxes. The inclusion of these additional non-labour items in the total amount of costs would reduce the weight of the labour component.

219. Regarding the second issue, the CCA submitted that the weight assigned to the labour component should reflect only the share of direct labour O&M expenses in total company costs. Specifically, the CCA did not agree with the approach of including contractor expenses and capitalized labour in the labour component. The CCA pointed out that contractor expenses do not consist entirely of labour expenses. In addition, since the EUCPI and the Alberta CPI already reflect labour cost trends, the CCA argued that using these indexes for the non-labour component would result in a double counting of labour inflation. Furthermore, the CCA submitted that capitalized labour does not have the same effect on a utility's earnings as O&M expenses.[221] Dr. Lowry provided the following explanation on this subject:

> [T]he way that construction labour prices affect a utility's accounting is different from the way that the direct labour price does. The direct labour price -- let's say there's a big run-up in the price because they discovered another big oilfield or something in northern Alberta. Then by the way the O&M expenses go up. But as for the capitalized piece, that's going to be recovered over 40 years, so it does not give -- and of course the reverse is true too. If there was suddenly the price of oil collapsed […] and all of a sudden there was lower labour prices in Alberta, it immediately lowers your O&M expenses, but it does not have that much of an affect on your capital cost.[222]

220. Finally, the CCA noted that using company-specific costs to establish the weights for the I factor in the subsequent PBR plans could weaken cost containment incentives, stating that the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. The CCA submitted that it has no objection to using company specific costs to establish the weights for the I factor in this proceeding only, provided it is clearly understood that in any future plan the cost shares will not be company-specific.[223]

Commission findings

221. The Commission explained in Section 5.2.1 of this decision that a relatively tight labour market in Alberta warrants the inclusion of a separate I factor component to reflect the unique labour inflation experience in the province. The Commission agrees with the companies that all workers employed by the companies or retained through a contractor are generally in the same Alberta labour market and subject to the same compensation inflation trends regardless of whether their work is accounted for as O&M or capital related labour.

222. Accordingly, the Commission considers that an I factor with a labour and a non-labour cost component represents an improvement over an I factor with an O&M and a capital

220 Exhibit 636, CCA argument, paragraph 52.
221 Exhibit 636, CCA argument, paragraph 54.
222 Transcript, Volume 13, page 2593, line 15 to page 2594, line 4.
223 Exhibit 636, CCA argument, paragraph 55 and Exhibit 372.01, AUC-CCA-18(a).

component, as previously approved in the ENMAX FBR plan, because it provides for a better tracking of inflation in prices of inputs that the companies use.

223. Dr. Lowry and Calgary pointed out that because both the EUCPI and the Alberta CPI include some labour, using these indexes along with the AWE or AHE indexes can result in a potential double-counting of labour inflation if all capitalized labour is removed from the non-labour category.[224] The Commission agrees. However, because no evidence was provided on the share of labour in either CPI or EUCPI,[225] correcting for any possible double-counting is problematic. One possible approach would be to adjust the weightings proposed by the companies by removing all capitalized labour as well as contractor expenses from the labour component. However, because capitalized labour and contractor expenses would comprise between 30 and 50 per cent of this component (based on the data for ATCO Electric, AltaGas and Fortis),[226] making this adjustment is tantamount to assuming that the share of labour in the Alberta CPI is between 30 and 50 per cent as well. In the absence of any information on the size of the labour component in the Alberta CPI, the Commission is not prepared to adopt this approach.

224. The CCA observed that contractor expenses do not consist entirely of labour expenses. However, as the ATCO companies pointed out, the contractors do not supply materials, and as such, their costs relate mostly to labour.[227] Similarly, Fortis also indicated that its contractor costs are "primarily labour, almost all labour."[228] AltaGas explained that because contractor costs consist of labour and services related to the use of contractor machinery, these costs tend to be driven by labour cost escalation, rather than general inflation.[229] The Commission agrees with this explanation.

225. With regard to the other concerns expressed by the CCA, such as the effect of capitalized labour on a company's earnings and whether it is necessary to include depreciation and return on rate base in the calculation of the I factor weights, the Commission observes that these proposals rely on the same rationale as the proposal to include a separate I factor component for the cost of capital. As explained in Section 5.2.1 of this decision, the Commission considers that no specific adjustments for the cost of capital need to be incorporated into the inflation index. Accordingly, the Commission accepts the companies' approach of using the sum of O&M and capital expenditures when calculating the weights for their respective I factors.

226. Finally, the Commission agrees with the CCA that, ideally, the weightings for the components comprising the I factor should reflect the industry-wide proportions of the relevant costs in order to provide the strongest competitive incentives. However, in this proceeding, the Commission was presented with no data to assess an alternative to examining the companies' own historical cost ratios relative to labour and non-labour components. For this reason, the Commission will rely on the weights calculated on the basis of the companies' historical costs, as provided in their PBR applications.

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224 Transcript, Volume 13, page 2593, lines 11-14 and Exhibit 636, CCA argument, paragraph 54.

225 For example, Dr. Ryan pointed out that Statistics Canada does not report the share of labour in the EUCPI (Exhibit 103.04, paragraph 21).

226 Estimates calculated by the Commission's staff based on the cost information provided in Exhibit 224.01; Exhibit 110.01, Appendix III, Composite I factor calculation; Exhibit 539 and referenced Rule 005 filings.

227 Exhibit 647, ATCO Electric reply argument, paragraph 76 and Exhibit 648.02, ATCO Gas reply argument, paragraph 117.

228 Transcript, Volume 11, page 2146, lines 15-18.

229 Exhibit 650, AltaGas reply argument, paragraphs 23 and 42.

227. In light of the above considerations, the Commission accepts the companies' method of calculating the weights for the I factor components. The Commission has examined the companies' historical ratios of labour to non-labour expenditures in recent years, as provided in the PBR applications and presented in tables 5-1 and 5-2 above. ATCO Electric's estimates resulted in a 65 per cent weighting of the labour component, although this ratio reflects the fact that ATCO Electric was the only company to apply a 50 per cent multiplier to its contractor costs.[230] The Commission does not agree with this adjustment. The Commission observes that the historical cost ratios are approximately 60 per cent labour and 40 per cent non-labour for the other companies (not including EPCOR). Accordingly, the Commission finds that a 60:40 weighting of the labour and non-labour components is a reasonable estimate of the balance of labour and non-labour costs for all companies, including ATCO Electric.

228. Nevertheless, the Commission has decided in the previous section of this decision to use Alberta CPI for non-labour costs. The Commission observed earlier in this section that the CPI includes some embedded labour. Therefore, using this index for the non-labour component together with the AWE index for the labour component may lead to a double-counting of labour costs. In this case, the 60:40 weighting would overstate the companies' input price inflation in years when growth in the Alberta AWE exceeds the growth in the Alberta CPI. Conversely, the companies' input price inflation would be understated in years when growth in the AWE is lower than the growth in the Alberta CPI. Accordingly, to temper the possibility that inflation in the companies' input prices will be overstated or understated, the Commission considers that a 55:45 ratio of labour to non-labour expenditures should be used for calculating the I factors in the companies' PBR plans.

229. Consistent with the findings in Decision 2009-035, in order to ensure that the companies' incentives will not be influenced by the relative rates of inflation between the components in the I factor, the Commission also finds that the 55:45 ratio of labour to non-labour expenditures should be held constant throughout the PBR term.[231]

230. EPCOR's proposed 80:20 labour to non-labour weighting reflects the company's proposal that the I-X mechanism be applied only to its non-capital related costs. As discussed in Section 2.3 of this decision, the Commission does not accept EPCOR's proposal to exclude all capital-related costs from the I-X mechanism. As such, the Commission directs EPCOR to use the 55:45 weighting in the calculation of its I factor.

5.3 Implementing the I factor

231. As the ATCO companies' expert Dr. Carpenter pointed out in his evidence, one of the difficulties in using the current year's inflation in the PBR formula is that the actual inflation indexes become available for each calendar year only in the first half of the following year, and there may not be any independent forecasts for the selected input price measures. To address this problem, Dr. Carpenter indicated that several methods could be used in practice. One method would be to accept a lag, either with or without a subsequent true up for the difference between the inflation actually experienced in a given year and the lagged inflation factor used to

[230] Exhibit 98.02, ATCO Electric application, Schedule 3-1.
[231] Decision 2009-035, paragraphs 147-148.

determine rates for that year. Alternatively, a forecast of expected inflation could be used with or without a subsequent true up to the actual inflation rate.[232]

232. ENMAX's FBR plan approved in Decision 2009-035 uses actual inflation from the previous year to set rates in a current year.[233] Specifically, ENMAX uses its selected input price indexes for the 12-month period ending December 31st of the previous year to set the I factor in the PBR formula and arrive at rates to be implemented on July 1st of the current year and to remain in effect until June 30th of the next year.[234]

233. Furthermore, in Decision 2010-146, the Commission recognized that the I factor indexes used by ENMAX may be periodically revised by Statistics Canada and ordered that these revisions be handled as a flow-through adjustment not subject to the materiality limit.[235]

234. The companies proposed two different approaches to implementing the I factor. AltaGas and EPCOR proposed to use an I factor mechanism similar to the one used by ENMAX. To accommodate the planned January 1st rate changes, AltaGas proposed that the inflation factor be calculated by computing annual price indexes for the 12-month period ending in June of the previous year. For example, in calculating rates for January 1, 2013, the AWE component of the I factor would be based on the change in the actual average AWE for the 12 months ending June 2012, as compared with the actual average AWE for the 12 months ending July 2011.[236] The UCA and Calgary agreed with this concept.[237]

235. An alternative method was put forward by ATCO Electric, ATCO Gas and Fortis and supported by the CCA. These companies proposed adopting a forecast inflation rate for the upcoming year with a subsequent revenue adjustment to true up to the actual inflation for that year. In supporting the I factor true-up approach, ATCO Gas argued that the 18-month lag between the inflation index used in the PBR formula and the actual inflation experienced by the companies could have a significant impact on its revenues, further amplified by the compounding effect of indexing. ATCO gas argued that, as a result, the inflation lag can cause windfall gains or losses, possibly triggering earnings sharing or a PBR re-opener.[238]

236. The ATCO companies also pointed out that the proposed I factor true-up does not amount to a true-up to actual companies' costs. Rather, it improves the accuracy of the inflation component of the indexing mechanism by truing up the I factor to the actual inflation index results.[239] Dr. Lowry on behalf of the CCA agreed that the use of a true-up for the actual inflation index results will produce a more accurate inflation adjustment and is warranted, particularly in light of the volatility of price inflation in Alberta.[240]

237. In contrast, AltaGas submitted that the lagged approach will be reasonably reflective of the company's input cost changes in the upcoming year and will provide a fair balance between accuracy and regulatory efficiency. As such, AltaGas argued that no I factor true-up was

232 Exhibit 98.02, written evidence of Paul R. Carpenter, page 15.
233 In other words, in year *t* the I factor will be based on the actual inflation indexes from year *t-1*.
234 Proceeding ID No. 12, Exhibit 15, EPC amended application, page 52.
235 Decision 2010-146, paragraphs 167-168.
236 Exhibit 110.01, Appendix I - Christensen Associates report, paragraphs 32-33.
237 Exhibit 634.02, UCA argument, paragraph 88; Exhibit 629, Calgary argument, page 22.
238 Exhibit 632, ATCO Gas argument, paragraphs 60-61.
239 Exhibit 631, ATCO Electric argument, paragraph 55 and Exhibit 632, ATCO Gas argument, paragraphs 58-59.
240 Exhibit 372.01, AUC-CCA-21(a).

necessary as it introduces an unnecessary level of complexity to the PBR plan and results in additional adjustments to future rates and additional regulatory filing requirements.[241]

238. EPCOR's expert, Dr. Ryan, also commented on the redundancy of the inflation correction procedure currently employed by ENMAX which requires recalculating the previous year's inflation factor if revised data are released.[242] Dr. Ryan noted that, since Statistics Canada series revisions can extend several years into the past, this could involve substantial recalculation and subsequent adjustments of prices in previous years without any obvious overall effect, except for allocating some part of price changes to a previous or subsequent year.

239. In Dr. Ryan's opinion, the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor, provided that the unrevised value is used as the basis for subsequent calculations. Dr. Ryan illustrated this concept with the following example:

> For example, if a series was 100 in Year 1 and 105 in Year 2, the inflation component for this series from Year1 to Year2 (to be used as part of the I factor in Year 3) would be 0.05 (or 5%). Now, if Statistics Canada was to revise the Year 2 series value to 104, and release the Year 3 series value of 107, then the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would simply be calculated as (107- 105)/105, and no adjustment because of the change from 105 to 104 would be needed, since this effect (from 104 to 105) has already been included in the previous year's inflation component. Similarly, if the Year 2 series value was revised to 106 (rather than 105), the inflation component for this series from Year 2 to Year 3 (to be used as part of the I factor in Year 4) would still be calculated as (107-105)/105 and no adjustment because of the change from 105 to 106 in Year 2 would be needed, as this effect (from 105 to 106) would be automatically included in the subsequent year's inflation component.[243]

240. At the same time, Dr. Ryan cautioned that more substantial revisions to a component data series would need to be examined on a case-by-case basis to determine whether other adjustments would be needed. Dr. Ryan proposed that, if a termination, substantial revision or modification to a Statistics Canada data series impacted the company's inflation factor, EPCOR would be able to apply for an appropriate amendment to its inflation factor in its first annual rate adjustment filing following the termination, substantial revision or modification.[244]

Commission findings

241. EPCOR and AltaGas proposed to use the actual inflation results for the most recent 12-month period to calculate the I factor for the upcoming year with no subsequent true-up, while the ATCO companies and Fortis proposed to forecast the I factor for the upcoming year, followed by a true-up to reflect the actual inflation in that year.

242. In the Commission's view, both approaches would eventually achieve the same purpose of reflecting the inflationary pressures on the companies' input prices. Under a forecast and true-up method, the forecast I factor is reconciled to the actual inflation indexes and rates are adjusted through a regulatory proceeding. Under the alternative approach, the true-up occurs automatically by virtue of using the actual inflation indexes from the preceding year; however,

241 Exhibit 628, AltaGas argument, page 15.
242 Exhibit 103.04, Dr. Ryan evidence, paragraph 37.
243 Exhibit 103.04, Dr. Ryan evidence, paragraph 37.
244 Exhibit 103.02, EPCOR application, paragraphs 74-75.

the true up is implemented after a longer period of regulatory lag. Both approaches represent a true-up to the inflation indexes and do not imply a true-up to the actual costs of the company, thus preserving the incentive properties of the PBR regime.

243. The main difference between the two methods is that the approach preferred by the ATCO companies and Fortis ensures that the impact of actual inflation in any given year is reconciled soon after the year's end, while the alternative approach of using the actual inflation from the previous year involves a certain lag for such a true-up to occur. In this proceeding, parties' concerns with the lagged approach seemed to be centered on the fact that the lag between the inflation index used in the PBR formula and the actual inflation experienced in the economy would expose the companies to windfall gains or losses, although these would be transitory.[245]

244. The Commission considers that if inflation is higher in some years and lower in other years, as appears to be the general case in the economy,[246] then using the most recent historical inflation rate will average out the effect of any regulatory lag over the PBR period. Indeed, as ATCO Gas observed in its argument, in the absence of a true-up, the I factor in 2009 would be higher than actual inflation. The opposite would have occurred in 2010, where the I factor without the true-up would be lower than actual inflation.[247] As such, inflation will tend to balance out over the PBR term, obviating the need to true-up the I factor through a separate regulatory proceeding.

245. When discussing the benefits of the two approaches, it is important to distinguish between the fact that inflation is generally positive (in other words, prices are increasing most of the time) and the fact that the actual inflation rate will increase year-over-year in some cases and will decline in others, although prices are still increasing. For example, as Table 5-3 above demonstrates, although the level of labour prices has been increasing consistently year over year from 1999 to 2010, the rate of change in salaries and wages (i.e., labour price inflation) went up and down during this period.

246. In order for the companies to be concerned with the lagged approach and the compounding effect to take place, the rate of inflation in each year would have to be consistently higher (or lower) than in the previous year. If it is higher in some years and lower in other years, as appears to be the general case in the economy, then using the most recent past inflation rate will average out the effect of the lags over the PBR period.

247. With respect to the concern that gains or losses resulting from the inflation lag may trigger earnings sharing or a re-opener, the Commission explained in Section 10 of this decision that in order to maximize the incentive properties of the PBR plans, ESM (earnings sharing mechanism) should not be part of the companies' PBR plans. As well, as set out in Section 8 below, the Commission will examine the need for re-openers on a case by case basis. Where relevant, the consequences of the inflation lag would be considered as part of any such review.

248. In light of these considerations, the Commission finds that the lagged approach currently used by ENMAX and proposed by AltaGas and EPCOR in this proceeding represents a better alternative as compared to the forecast and true-up method proposed by the ATCO companies and Fortis. For the purposes of clarity, based on the availability of Statistics Canada indexes, the

245 Transcript, Volume 4, pages 629-630.
246 See, for example, the inflation indexes chart in Exhibit 512.02, AUC-Fortis-7 attachment.
247 Exhibit 632.01, ATCO Gas argument, paragraph 61.

Commission directs the companies in their annual PBR rate adjustment filings to use the inflation indexes for the most recent 12-month period for which data is available, as specified in the formula below. The Commission considers that this approach will provide a fair balance between accuracy and regulatory efficiency and will make the companies' PBR plans more transparent and simple to understand thereby furthering the objectives of the third Commission PBR principle.

249. On the issue of the periodic revision of historical inflation indexes by Statistics Canada, the Commission agrees that Dr. Ryan's proposed method of accounting for revisions to the indexes by means of using the unrevised values in the subsequent I factor calculations represents an improvement over the rate adjustment method currently employed by ENMAX. Accordingly, the Commission finds that the periodic revision of inflation indexes by Statistics Canada need not affect the calculation of the I factor and directs the companies to use the unrevised actual index values from the prior year's I factor filing as the basis for the next year's inflation factor calculations.

250. The Commission also agrees with Dr. Ryan's recommendation that if a termination, substantial revision or substantial modification to the Statistics Canada data series used in the companies' I factors occurs, such changes should be brought forward to the Commission as part of the annual PBR rate adjustment filings. Any changes to the I factors arising from such data series modifications will be dealt with on a on a case-by-case basis.

5.4 Commission directions on the I factor

251. The Commission directs that the I factor to be used in the PBR plans of the Alberta utilities shall be calculated as follows:

$$I_t = 55\% \text{ x } AWE_{t-1} + 45\% \text{ x } CPI_{t-1},$$

where:

I_t	Inflation factor for the following year.
AWE_{t-1}	Alberta average weekly earnings index for the previous July through June period.[248]
CPI_{t-1}	Alberta consumer price index for the previous July through June period.[249]

6 X factor

6.1 Purpose of the X factor

252. The X factor is one of the key elements of PBR plans employing an I-X indexing mechanism to adjust a regulated company's prices or revenues each year during the PBR term. In general terms, the X factor can be viewed as the expected annual productivity growth during the

[248] The selection of the start and ending months for the 12-month period reflects the latest published Statistics Canada data prior to September.

[249] The Commission recognizes that Alberta CPI information for July may be available when the September annual PBR rate adjustment filing is made but the Commission is directing the July through June period in order to ensure the companies have enough time to prepare their filings.

PBR term. Through the I-X mechanism, a PBR plan is designed so that the changes in the prices of the company's distribution services reflect changes in input prices as reflected by the I factor and the rate of expected productivity growth.

253. The X factor, combined with the I factor, is designed to mirror the pressures of competitive market forces. In competitive markets, firms are not able to earn additional profits from productivity improvements that their competitors also adopt because competition acts to drive down prices.[250] However, to the extent that the firm is more productive than its competitors, it earns an extra return, which serves as a reward for its better than average productivity. Conversely, firms that are less productive than average earn lower returns.[251] The X factor in a PBR plan imitates these pressures by requiring the regulated companies to adjust their prices to reflect the expected productivity growth.

254. NERA and other experts in this proceeding drew attention to the fact that the magnitude of the X factor has no influence on the incentives for the company to reduce costs.[252] As Dr. Carpenter explained in his evidence:

> Under PBR, a utility which successfully saves a dollar of operating expenditure keeps that dollar (or a portion of the dollar under an earnings sharing mechanism). The opportunity to save the dollar (or portion thereof) of expenditure is unrelated to the level of rates, and therefore the magnitude of the productivity factor does not influence the incentive to find the savings.[253]

255. AltaGas explained that while the size of the X factor does have an impact on the company's return, it is the decoupling of the revenues and prices from the company-specific costs that provide the incentives, rather than the magnitude of the X factor itself.[254] Similarly, EPCOR and the CCA noted that it is the length of the term of the PBR plan (i.e., regulatory lag) that is the primary source of the incentives.[255]

Commission findings

256. During the term of the PBR, a company's prices or revenues will change with inflation, represented by the I factor, adjusted by the expected productivity growth represented by the X factor. Customers of a regulated company under PBR directly benefit from annual rates that are adjusted to reflect this expected productivity growth.

257. The Commission agrees with the experts of the companies, NERA and the CCA, that while the size of the X factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. As the companies' and the CCA's experts pointed out, the PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time of the PBR term, and not from the magnitude of the X factor itself.

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250 Exhibit 98.02, Carpenter evidence, page 18.
251 Exhibit 616.02, page 13, William J. Baumol, "Productivity Incentive Clauses and Rate Adjustment for Inflation," *Public Utilities FORTNIGHTLY*, (22 Jul. 1982).
252 Transcript, Volume 1, page 117, lines 10-15; Exhibit 633, Fortis argument, paragraphs 140-141.
253 Exhibit 98.02, Carpenter evidence, page 17.
254 Exhibit 628, AltaGas argument, page 32.
255 Exhibit 630.02, EPCOR argument, paragraph 80; Exhibit 636, CCA argument, paragraph 105.

6.2 Approaches to determining the X factor

258. As the record of this proceeding demonstrates, there are different approaches to setting the productivity target included in the X factor of a PBR plan. In Decision 2009-035, the Commission expressed its preference for an approach to determining the X factor that is based on the average rate of productivity growth in the industry as a whole.[256] As NERA explained, under this concept, the purpose of the X factor is to reflect the long-term underlying industry productivity trend.[257] NERA favoured this approach to the determination of the X factor as evidenced by the two reports[258] prepared by NERA on total factor productivity for the regulated electric utility industry. While differing from NERA on how to determine the underlying industry productivity trend, EPCOR, AltaGas and the ATCO companies used this approach to setting the X factor.[259]

259. The CCA generally agreed with NERA's opinion that the X factor should reflect the productivity growth of the industry in which the company operates. In addition to using the index approach employed by NERA for estimating the industry productivity trend, the CCA's experts relied on an econometric model for this purpose as well. In PEG's view, the econometric approach produces a more customized productivity estimate reflecting Alberta business conditions.[260] The econometric approach to measuring TFP is further discussed in Section 6.3.4 below.

260. In Fortis' view, the analysis of the historical industry productivity trend needs to be complemented with an assessment of a company's going-forward costs and especially capital expenditure costs.[261] NERA pointed out that this type of X factor derivation resembles the building blocks concept currently employed by regulators in the United Kingdom and Australia. Under this approach, the X factor does not come from a TFP growth study, rather it is calculated as the value that would set the customer rates at a level to recover the company's cost of service revenue requirement over a forecast period.[262] Fortis' expert, Ms. Frayer, explained that in these circumstances, the X factor represents not a productivity factor itself, but rather a smoothing factor for rates, while the productivity target is embedded in the forecast of future operating and capital costs that are then used to forecast a revenue requirement and rate schedule.[263]

261. The UCA's preferred approach to determining the X factor centered upon efficiency benchmarking and consideration of a level of inefficiency for each particular company.[264] Under this method, the regulator must perform a benchmarking assessment of historical efficiency for a comparator group of companies, based upon a comprehensive analysis of their costs including capital, labour, materials and power losses. Following this analysis, the companies are assigned different productivity targets that are set higher, the more inefficient any particular company was

256 Decision 2009-035, paragraph 176.
257 Exhibit 391.02, NERA second report, paragraph 36.
258 Exhibit 80.02, NERA report and Exhibit 391.02, NERA second report.
259 Exhibit 630.02, EPCOR argument, paragraph 67; Exhibit 628, AltaGas argument, page 29; Exhibit 631, ATCO Electric argument, paragraph 84; Exhibit 632, ATCO Gas argument, paragraph 94.
260 Transcript, Volume 13, pages 2529-2530.
261 Transcript, Volume 11, page 2104, lines 23-24 and Exhibit 474.01, Fortis rebuttal evidence, paragraph 19.
262 Exhibit 391.02, NERA second report, pages 27-28.
263 Exhibit 474.02, Frayer rebuttal, page 38.
264 Transcript, Volume 17, page 3167, line 1 and Exhibit 299.02, Cronin and Motluk UCA evidence, pages 117-125.

found to be as compared to its peers (or, in other words, the further away a company was found to be from the efficiency frontier).[265]

262. In the absence of a complete set of the detailed historical cost information for Alberta gas and electric distribution companies upon which to base the benchmarking assessment, the UCA experts recommended constructing a menu which pairs data on a range of probable productivity performances with the associated ROE (return on equity) that would be permitted with each productivity choice. In the UCA's view, the menu approach to the X factor would mitigate the risks from information asymmetry and incent the companies to reveal their performance potential.[266]

263. For practical purposes, Dr. Cronin and Mr. Motluk recommended the use of the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[267] This menu was based on the analysis of the performance of 48 distribution utilities in Ontario operating under the cost of service (1988 to 1993) and PBR (1993 to 1997) regimes.[268] The UCA's X factor menu recommendation is as follows:

Table 6-1 The X factor menu proposed by the UCA's experts[269]

Selection	X factor (in per cent)	ROE ceiling (in per cent)
A	1.25	10
B	1.50	11
C	1.75	12
D	2.00	13
E	2.25	14
F	2.50	15

264. Dr. Cronin and Mr. Motluk explained that under this arrangement, the companies can choose a combination of productivity growth and ROE: a higher productivity target would permit higher returns.[270] The UCA experts explained that the menu above has an earnings sharing mechanism embedded in it. In particular, the menu selections were designed in such as way that moving among menu choices (for example, from option A to option B) results in a 57:43 earnings sharing between a company and the ratepayers. At the same time, if a company's actual ROE exceeds the earnings ceiling associated with a particular menu option, 100 per cent of earnings above the ROE cap is given to ratepayers.[271]

Commission findings

265. NERA explained that because in competitive markets prices move according to the productivity of the industry in question rather than the particular costs of one company, it has

265 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 131-136.
266 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 140-141.
267 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.
268 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
269 Exhibit 299.02, Cronin and Motluk UCA evidence, page 154.
270 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 153 and 154.
271 Transcript, Volume 17, page 3205, lines 11-20.

become customary for regulators in the design of objective PBR formulas to set the X factor based on the underlying trend in industry productivity growth.[272]

266. Similarly to the discussion in the proceeding dealing with ENMAX's FBR plan, in this proceeding the parties offered several principal approaches to determining the X factor. With respect to Fortis' approach, which involved setting the X factor based on the forecast revenue requirement over the PBR term, the Commission agrees with NERA's characterization that this method essentially resembles a five-year test period under traditional cost of service rate making.[273]

267. The Fortis approach first determines the forecast revenue requirement over the PBR term and then develops a formula to be applied to rates which will yield the forecasted revenue requirement each year. As NERA observed, while Fortis' approach resembles the practices of regulators in the United Kingdom and Australia, it is inconsistent with the institutional foundation for performance-based-rate regulation generally adopted in Canada and the United States.[274] Accordingly, the Commission restates its opinion expressed in Decision 2009-035 that this method effectively involves a multi-year cost of service rate setting exercise and changes the theoretical basis for utilizing the X factor, which is to emulate the incentives of a competitive marketplace for the benefit of ratepayers and shareholders alike.[275]

268. The efficiency frontier and benchmarking method advocated by the UCA's experts represents yet another approach to determining the value of the X factor. In contrast to productivity studies that deal with the rate of industry productivity growth over time, the efficiency frontier analysis focuses on a company's productivity level (i.e., efficiency[276]) at a particular time in relation to comparable companies. In other words, instead of looking at how the industry's productivity changes over time, this method examines whether one particular company is less or more efficient at the time of measurement as compared to its peers.

269. In the Commission's view, the efficiency benchmarking analysis is prone to two major criticisms. First, as NERA and Dr. Carpenter explained, the efficiency levels are hard to estimate as this type of analysis requires a multitude of historical company-specific data, which exhibit a great deal of year to year volatility and are prone to errors.[277] Indeed, as the UCA witnesses observed, this method of developing the X factor would busy "hundreds of analysts" both of the companies and the regulator.[278]

270. More importantly, Dr. Makholm and Dr. Carpenter pointed out that in practice it is virtually impossible to determine whether a firm is or is not efficient by looking at benchmark data alone, since relative efficiency depends on a boundless number of variables, both observable

272 Exhibit 80.02, NERA report, pages 1 and 3.
273 Exhibit 195.01, AUC-NERA-9(a).
274 Exhibit 391.02, NERA second report, page 9.
275 Decision 2009-035, paragraph 174.
276 The difference between terms "productivity" and "efficiency" is a definitional one. Dr. Makholm agreed when people refer to productivity, they usually refer to productivity growth, and they just leave out the word "growth" because productivity growth is measured in a percentage and some people confuse productivity growth with the actual efficiency at a point in time or the efficiency of one company. (Transcript, Volume 3, page 528, lines 5-25.)
277 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
278 Transcript, Volume 17, page 3227 and pages 3430-3431.

and unobservable.[279] Factors such as age of plant, soil type, weather and geography, customer density, etc., are to be taken into account when considering efficiency levels. In these circumstances, inadvertently leaving out an important productivity driver may invalidate the results of the study.[280] Overall, the Commission agrees with the following criticism by NERA of the UCA's approach:

> So if you get into the business of drawing a productivity frontier and concluding that you know why a company is not on that frontier, that is, it's inefficient, you're making two errors. One, the error is concluding that you've actually measured a frontier, and we contend that, to a certain extent, you're measuring errors. And the second is that we economists have anything to say about whether a firm is or is not productive with the scarcity of data we have before us. Could be that you don't lie in the efficiency frontier because your utility is in a swamp. But if we can't measure swampiness, we have no way of correcting for that.[281]

271. In contrast, because TFP (total factor productivity) studies (such as the one prepared by NERA in this proceeding) focus on rates of change in productivity within an industry, not levels, the unique cost features of any particular company cancel out in the process. In other words, these productivity studies do not examine whether one firm has a greater level of output for the same inputs levels as another firm. Rather, the focus is to study how the ratio of outputs to inputs changes over time for the industry as a whole.

272. Under the UCA's efficiency benchmarking approach to developing the X factor, a company is incented to catch up to the level of efficiency experienced by peer companies deemed to be more efficient by the regulator, rather than to meet or beat the industry rate of productivity growth. Because of the practical and theoretical problems associated with measuring efficiency levels described above, the Commission does not accept this approach for the purposes of PBR in Alberta.

273. With respect to the menu approach to setting the X factor proposed as an alternative by the UCA's experts, for the reasons outlined below, the Commission is not prepared to adopt this approach.

274. First, similar to a discussion in sections 6.3.3 and 6.3.7 of this decision, the Commission is not persuaded that the UCA's X factors, based on ten-year data for Ontario distribution companies, represent a better indicator of the underlying long-term industry productivity trend than NERA's TFP based on a broad sample of companies over the period of 1972 to 2009. Second, as ATCO Electric pointed out, it is not clear why the X factor/ROE tradeoffs presented in the menu were reasonable for the Alberta companies.[282] In particular, the ROE ceilings in the menu do not correspond to the Commission's determinations in the most recent Generic Cost of Capital decision.[283] In addition, EPCOR pointed out that the UCA's menu approach presupposes the inclusion of an ESM (earnings sharing mechanism) in the PBR design.[284] The Commission determines in Section 10 of this decision that in order to maximize the incentive properties of PBR, an ESM should not be part of the companies' plans.

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279 Transcript, Volume 3, pages 490-491 and Volume 7, pages 1244-1245.
280 Transcript, Volume 18, pages 3482-3483.
281 Transcript, Volume 3, page 491, line 20 to page 492, line 6.
282 Exhibit 647, ATCO Electric argument, paragraph 123.
283 Transcript, Volume 17, pages 3204-3205.
284 Exhibit 646.02, EPCOR reply argument, paragraph 74.

275. In addition, the Commission observes that the Ontario Energy Board did not accept the menu approach, partly because of the concerns regarding "the unnecessary complexity encompassed in the proposed menu."[285] A similar concern was expressed by EPCOR's expert, Dr. Weisman, who supported his view with the following quotation from an academic article:[286]

> Allowing for a choice among incentive plans can complicate the regulatory task, thereby sacrificing simplicity. The costs of reduced simplicity must be weighed against the expected gains from creating "win-win" situations.[287]

276. The Commission shares these concerns. In the Commission's view, the UCA's menu approach does not conform to AUC Principle 3, which requires, among other things, that a PBR plan should be easy to understand, implement and administer. Based on the above considerations, the Commission does not accept the menu approach proposed by the UCA.

277. The Commission restates the preference expressed in Decision 2009-035 for an approach to setting the X factor that is based on the long-term rate of productivity growth in the industry. During the hearing, NERA explained the rationale behind this approach as follows:

> The theory that we're drawing from doesn't require such precision. It says that there is an industry out there that's doing something. If it's a competitive industry -- it's an industry for making [hockey sticks], I don't know. [...] And of all the makers of hockey sticks, there's a productivity trend for hockey stick makers, and if you can't keep up, your business will fail. We don't need to be vastly more sophisticated than to measure the productivity of the hockey stick industry and use that as our way of allowing regulatory lag to eke out a few more years to avoid a couple of rate cases and to allow a little more productivity pressure to be visited on utility managements to try to make the businesses run better.[288]

278. As NERA emphasized, this concept corresponds to the underlying theory behind the PBR plans in Canada and the United States: to permit regulated prices to change to reflect general price changes and industry productivity movements without the need for a base rate case. The effect is to lengthen regulatory lag and better expose regulated utilities to the type of incentives faced by competitive firms.[289]

279. Given the approach approved above, the starting point for determining the X factor is to estimate the underlying industry TFP growth for the services included in the companies' PBR plans. Then, it is necessary to consider any adjustments to the industry TFP that may be required to arrive at an X factor for Alberta gas and electric distribution companies. And finally, the Commission will consider whether a stretch factor is justified and if so, the size of a stretch factor. Sections 6.3 to 6.5 below deal with each of these steps.

[285] Exhibit 299.02, Cronin and Motluk UCA evidence, page 174.
[286] Sappington, David E. M., *Designing Incentive Regulation*. Review of Industrial Organization, Volume 9, 1994, page 260.
[287] Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., page 16.
[288] Transcript, Volume 3, page 476, line 17 to page 477, line 5.
[289] Exhibit 391.02, NERA second report, paragraph 2.

6.3 Total factor productivity

6.3.1 The purpose of total factor productivity studies

280. As set out in the previous section of this decision, the Commission opted for an approach to set the X factor based on the average rate of productivity growth in the industry. Under this approach, the first step in determining the X factor is to examine the TFP (total factor productivity) of the electric and gas distribution industries.

281. For this purpose, the Commission engaged NERA to conduct a TFP study applicable to Alberta gas and electric companies.[290] NERA filed its report entitled "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative" dated December 30, 2010 as Exhibit 80.02. The study was based on a population of 72 U.S. electric and combination electric/gas companies from 1972 to 2009. NERA measured the TFP of the distribution component of the electric companies. Costs related to power generation and transmission, as well as general overhead costs, were not included in the study.[291]

282. In addition to NERA's study, PEG on behalf of the CCA performed a TFP also referred to as a multifactor productivity (MFP)[292] study for the gas distribution industry. PEG's analysis examined the productivity growth of 34 U.S. gas distribution companies for the period from 1996 to 2009. In its study, PEG calculated the TFP trends of the sampled companied as providers of gas transmission, storage, distribution, metering and general administration services.[293]

283. In its report, NERA explained that productivity growth for a particular firm, by definition, is the difference between the growth rates of a firm's physical outputs and physical inputs. That is, to the extent that a firm's productivity grows, it will transform its inputs into a greater level of output. Accordingly, the task of productivity measurement involves comparing a firm's outputs and inputs over time. Total factor productivity measures all of a firm's inputs and outputs, combining the various inputs and outputs into single input and output indexes suitable for comparison to one another for purposes of measuring the rate of productivity growth over time.[294]

284. NERA pointed out that the main purpose of the TFP growth study is to measure the underlying long-term trend in industry productivity growth.[295] The UCA agreed with NERA that TFP should reflect long-term productivity growth.[296] Similarly, ATCO Electric and ATCO Gas expressed their understanding that a TFP study produces an estimate of the long-term TFP growth of the industry. At the same time, the ATCO companies cautioned that in using the TFP result as a starting point for determining the X factor in a PBR plan, it is necessary to

290 Exhibit 71.01, AUC letter – Retention of Consultant to Develop Basic X Factor, September 8, 2012.
291 Exhibit 80.02, NERA report, page 6.
292 Dr. Lowry explained that, strictly speaking, MFP is a more accurate term than TFP, since the latter implies that all of the company's inputs are taken into account in its computation, which is often not possible or practical to do. However, Dr. Lowry agreed that generally these terms can be used interchangeably. MFP is the term used by Statistics Canada (Transcript, Volume 13, page 2451).
293 Exhibit 307.01, PEG evidence, page 2.
294 Exhibit 80.02, NERA report, page 5.
295 Exhibit 391.02, NERA second report, paragraph 38.
296 Exhibit 634.02, UCA argument, page 21, paragraph 117.

consider whether the historical long-term productivity trend of the industry is a reasonable estimate of the expected productivity growth of the utility during the PBR plan term.[297]

285. EPCOR concurred that the purpose of the TFP is to assist in determining what productivity growth is expected to be over the course of the PBR term.[298] In contrast, IPCAA contended that TFP analyses have no apparent relevance to electric distribution system economics, save as broad long-term overall indicators.[299] However, IPCAA's concerns in this regard appeared to center on the fact that TFP studies rely on energy throughput as an output measure, as further discussed in Section 6.3.6 of this decision.

286. In Fortis' view, since statutory requirements must take precedence over other ratemaking principles, the TFP study should not be the core foundation for the Commission's determination of the X factor. Specifically, Fortis submitted that because the Alberta statutory framework under the *Electric Utilities Act*, SA 2003, c. E-5.1, mandates that the rates being set must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service, and because rates are being set for the initial PBR term, expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the long-term industry productivity growth.[300]

Commission findings

287. As set out in Section 6.2 above, the objective of the PBR plan sought by the Commission is to emulate the incentives experienced by companies in competitive markets where prices move according to the productivity of the industry in question rather than with the particular costs of a company. Under this approach, the first step in determining the X factor is to examine the underlying industry productivity growth over time, commonly measured by total factor productivity.

288. Accordingly, the Commission agrees with NERA that, in these circumstances, the purpose of the TFP study is to estimate the long term productivity growth of the industry in question.[301]

289. The Commission does not share Fortis' view that expectations as to the achievable productivity growth for the PBR term must prevail over considerations of the industry TFP when determining the X factor. In the Commission's view, Fortis' submission is reflective of the company's overall approach to determining the X factor as a mechanism to recover the forecast cost of service revenue requirement over the PBR term. As set out in Section 6.2 above, the Commission does not agree with this approach.

290. Fortis emphasized that the *Electric Utilities Act* stipulates that the companies' rates must provide a reasonable opportunity to recover the prudent costs of the provision of the regulated service. In the Commission's view forecasting the projected revenue requirement over a PBR term is not the only way to satisfy this statutory mandate. In that regard, the Commission agrees with NERA's explanation that the rationale behind the X factor (to which the TFP study contributes) is to emulate the incentives of competitive markets as they relate to productivity. In

297 Exhibit 631, ATCO Electric argument, paragraph 81 and Exhibit 632, ATCO Gas argument, paragraph 90.
298 Exhibit 630.02, EPCOR argument, paragraph 62.
299 Exhibit 306.01, Vidya Knowledge Systems evidence, page 5.
300 Exhibit 633, Fortis argument, paragraphs 100-103.
301 Exhibit 391.02, NERA second report, paragraph 38.

competitive markets, if a company achieves greater productivity growth than the industry, it is rewarded by larger earnings in the short run. If a company's productivity growth is lower than the industry productivity, its earning suffer in the short run.[302] Accordingly, in the Commission's view, the approach to determining the X factor based on the average productivity growth in the industry together with the selection of the I factor and the other features of the approved PBR plans provide regulated companies with a reasonable opportunity to recover their prudent costs of providing the regulated services.

6.3.2 Relevant time period for determining the TFP

291. The appropriate time period over which to calculate TFP for purposes of the companies' PBR plans garnered much attention in this proceeding. NERA recommended the use of its full set of data from 1972 to 2009, being the longest time period available from the Federal Energy Regulatory Commission (FERC) Form 1 dataset that NERA relied on.[303] The majority of other parties recommended a substantially shorter period.

292. NERA pointed out that the TFP growth analysis should span a sufficient number of years to mitigate the effects of business cycles or other idiosyncratic swings associated with annual changes in the use of inputs and outputs, for example, major capital replacements. Consequently, NERA argued that the more years of data that are added to the study, the more the effects of year-to-year changes in TFP growth are moderated and a picture of long-term productivity growth emerges.[304] As a result, NERA's TFP calculation was based on the 38 years of available data.

293. In its second report NERA provided additional reasons in support of its position to use the longest time period available. NERA pointed out that in a competitive market, from which the incentives inherent in PBR plans are drawn, equilibrium prices are affected only by changes in long-run average cost. Short-run changes in productivity, even industry-wide changes in productivity, do not cause firms to enter or leave an industry.

294. Furthermore, on the issue of whether a more recent period is more reflective of the expected productivity growth in the coming years as advocated by most other parties, NERA argued that unless there is reliable proof to the contrary, the best and most supportable economic assumption is that while productivity growth may fluctuate in an erratic manner in the short term, or in a longer-term cyclical manner, it will eventually revert back to its long-term underlying trend.[305]

295. NERA noted that if one suspects that any of the TFP growth series are not stable in the long term (thereby justifying a departure from the use of long-term industry data), the appropriate response to such suspicion is to implement a statistical testing procedure in accordance with accepted research in the area of "structural breaks." In that regard, NERA experts explained that such analysis involves a two-step process: first, it is necessary to postulate a theory about why a structural break could have occurred, and, second, it is necessary to perform a number of statistical tests to see if the postulated hypothesis is supported by the data.[306] Dr. Makholm emphasized that performing an ex post statistical analysis of visual data without

302 Exhibit 195.01, AUC-NERA-8(a).
303 Transcript, Volume 1, pages 44-47.
304 Exhibit 80.02, NERA report, page 6.
305 Exhibit 391.02, NERA second report, page 14.
306 Transcript, Volume 1, pages 81-85.

having a supportable hypothesis for a structural break harms the process and biases the researcher.[307]

296. Dr. Makholm observed that he was not aware of any academic studies that would suggest that a structural break occurred at any time within the 1972 to 2009 time period for which data were available with respect to the electric distribution industry in North America.[308] As a result, NERA supported the use of the full time period as the most objective basis for the TFP calculation. Calgary supported this position.[309]

297. The companies' experts contended that NERA's sample period, especially the early part of it, was not relevant for estimating the industry's current TFP trends or the trends that might be expected to prevail during the PBR term. Specifically, ATCO and EPCOR experts in their respective evidence pointed out that in the 1970s and 1980s, the utilities sector was vertically integrated, owning and operating generation facilities with little wholesale and no retail competition. Dr. Carpenter and Dr. Cicchetti concluded that productivity improvements pertaining to the vertically integrated utilities observed in the early part of NERA's study period were unlikely to be realized by today's unbundled distribution companies and as a result, a more recent period should be used for estimating the industry TFP.[310]

298. Furthermore, to test NERA's conclusion that a structural break had not occurred in the electric distribution industry, Dr. Cicchetti performed a number of statistical tests on NERA's productivity data and found that the TFP growth in the 1999 to 2009 period was statistically different than in prior years. Dr. Cicchetti concluded that a structural break occurred in 1999 and, therefore, a more recent period should be used for the purpose of the TFP and X factor determinations.[311]

299. Ms. Frayer on behalf of Fortis also noted that there have been structural changes in the electric utility sector involving changes in investment trends, technology deployment, operating practices, customer consumption patterns, and regulatory incentives. In addition, Fortis' expert indicated that as industries and firms get more and more efficient, it is unreasonable to assume that they should sustain the same level of productivity growth over time. Accordingly, Ms. Frayer's analysis was mostly based on the data from the years 2000 to 2009.[312]

300. In the same vein, based on their observation of the cumulative rate of TFP growth, AltaGas experts argued that a significant break in the productivity trend occurred around the year 2000. Specifically, Dr. Schoech observed that prior to 2000, the TFP for the U.S. electricity distributors in the NERA study grew at a substantial 1.6 per cent, while since 2000, the TFP has been declining at the approximate rate of -1.4 per cent. Similar to the other companies' experts, Dr. Schoech offered restructuring of the industry and changing consumption patterns as possible explanations for changes in the productivity.[313]

301. In developing their recommendations as to the relevant time period for the TFP calculations, the companies' experts also considered regulatory precedents. Dr. Cicchetti noted

307 Transcript, Volume 1, page 88, lines 7-15 and page 95, lines 11-19.
308 Transcript, Volume 1, page 91, line 23 to page 92, line 2.
309 Exhibit 629, Calgary argument, page 23.
310 Exhibit 103.05 Cicchetti evidence, page 10 and Exhibit 98.02, Carpenter evidence, page 21.
311 Exhibit 473.07, Cicchetti rebuttal evidence, page 14.
312 Exhibit 474.02, Frayer rebuttal evidence, pages 18-20 and Exhibit 100.02, Frayer evidence, page 79.
313 Exhibit 110.01, Christensen associates evidence, pages 11-12.

that based on his experience with PBR plans for energy utilities, the typical range for estimating the industry TFP growth is about 10 to 11 years.[314] Dr. Carpenter indicated that other TFP studies that he had seen generally use time frames no longer than 10 to 15 years.[315] Ms. Frayer pointed to a number of TFP studies used by other regulators with sample periods from four to 13 years.[316]

302. PEG agreed that there is some value in a shorter period because even long term drivers of TFP growth such as technological change can vary over a period of several decades. Dr. Lowry noted that in the past he often advocated a period of at least 10 years, but recent empirical results and NERA's testimony persuaded him that a minimum of 15 years is typically more desirable.[317]

303. In reviewing NERA's TFP estimate, PEG submitted that the relevant time period should essentially focus on the concept of a business cycle. As Dr. Lowry explained, because NERA's study used delivery volumes as an output measure, the resulting TFP is highly sensitive to changes in economic conditions. Therefore, Dr. Lowry advocated that when choosing the relevant time period, it is necessary to choose a start and end date that are at a similar point with respect to the business cycle, so that the key demand drivers are at the same levels.[318]

304. In that regard, Dr. Lowry observed that the last two years in NERA's sample, 2008 to 2009, were characterized by a deep recession and he recommended excluding these years to avoid distorting the long-run TFP trend. As a result, the CCA expert recommended a sample period for NERA's TFP study that ends in 2007 (avoiding the two recession years) and begins in 1988, a year with similar values for two key volume driver variables, cooling degree days and the unemployment rate.[319] For the purpose of its MFP study of U.S. gas distribution companies, PEG used the sample period of 14 years from 1996 to 2009 based on Dr. Lowry' judgment and experience.[320] PEG noted that this was the longest period available for the dataset on which PEG relied.[321] The CCA's expert explained that a 2009 sample end date was acceptable in this case, since his study did not use a volumetric output index and therefore would not be subject to volume related impacts of the 2008 to 2009 recession.

305. With respect to the 10 to 15-year timeframes advocated by the companies' experts relying on the NERA study, PEG contended that the suggested sample periods do not have an objective basis. In particular, Dr. Lowry noted that the companies have provided no credible explanation of why the sample period should begin just as the period of slower productivity growth begins. Moreover, Dr. Lowry reiterated his opinion that if a substantially shorter sample period (e.g., 10 to 15 years) such as those advocated by company witnesses is to be entertained, the exclusion of the 2008 to 2009 recession years becomes imperative for recognition of a long-term trend given the volumetric output index utilized in the NERA study.[322]

314 Exhibit 103.05 Cicchetti evidence, paragraph 18.
315 Exhibit 98.02, Carpenter evidence, page 25.
316 Exhibit 474.02, Frayer rebuttal evidence, page 21.
317 Transcript, Volume 13, pages 2490-2491.
318 Transcript, Volume 13, pages 2490-2491 and pages 2502-2503.
319 Exhibit 569.01, PEG evidence errata, page 9.
320 Transcript, Volume 13, pages 2490-2491.
321 Exhibit 372.01, AUC-CCA-5(a).
322 Exhibit 569.01, PEG evidence errata, pages 7-9.

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306. The length of a sample period can be a critical issue when indexes are used to estimate long run productivity trends, as demonstrated by the fact that just removing the last two years from NERA's sample period raises the TFP growth trend from 0.96 to 1.13 per cent.[323] The CCA submitted that when selecting the relevant sample period for a TFP study, the following two objectives must be considered:

- smooth out the effect of cost and output volatility
- capture the TFP growth trend that is most likely to be pertinent during the PBR plan period[324]

307. Most experts in this proceeding agreed that the time period for the TFP measurement should be long enough to smooth out the inevitable year-to-year variation in results that obscures the long term productivity trend of the industry.[325] As Ms. Frayer observed, specific annual circumstances with respect to weather and consumption, capital spending, labour, etc., contribute to the volatility of year-to-year TFP numbers.[326] There appeared to be an agreement among the parties that a sample period of at least 10 years is desirable for the purpose of determining the long-term industry TFP.[327]

308. However, much of the debate in this proceeding was centered on the issue of what historical time period to use to predict the productivity growth likely to be experienced by the industry during the PBR term. NERA's experts contended that unless the TFP growth series is not stable in the long term, as demonstrated by a structural break, the best economic assumption is that the industry productivity growth will eventually revert back to its long-term underlying trend.[328] Therefore, the use of the longest time period for which data is available is warranted absent evidence of a structural break in the productivity of the industry.

309. While accepting that a long-term productivity measure is required, the companies' experts contended that the period recommended by NERA was too long. These experts pointed to a number of changes in the electric distribution industry over time, of which the unbundling of distribution and generation facilities and the introduction of retail competition in the mid 1990s were the most significant, and suggested that the underlying industry TFP trend had changed.[329] In other words, using NERA's terminology, the companies hypothesized that a structural break in the industry productivity trend had occurred.

310. A discussion arose during the hearing as to whether restructuring and various other changes to the electric distribution industry can be characterized as a structural break that alters the long-term industry productivity trend.[330] NERA was of the opinion that the determination on

323 Exhibit 307.01, PEG evidence, page 36.
324 Exhibit 636, CCA argument, paragraph 63.
325 See, for example, Exhibit 80.02, NERA report, page 6; Exhibit 307.01, PEG evidence, page 19; Exhibit 98.02, Carpenter evidence, page 25.
326 Exhibit 100.02, Frayer evidence, page 63.
327 Exhibit 307.01, PEG evidence, page 28, and Transcript, Volume 13, page 2494, line 6; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
328 Exhibit 391.02, NERA second report, page 14.
329 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
330 See for example, Transcript, Volume 3, pages 477-481; Volume 4, pages 570-571; Volume 8, pages 1400-1403; Volume 11, pages 1995-1997; Volume 11, pages 2109-2113.

the subject of structural breaks lies outside the scope of regulatory proceedings and belongs to a realm of academic study. Dr. Makholm stated in testimony:

> [W]e want to stress the importance of making sure that something that would have such a severe affect on a TFP growth trend as bifurcating the study period would not come about lightly, and not come about in a contested proceeding among interested parties where the minutiae of econometrics or empirical work often go way beyond the heads of even the experts in the room. And in that respect, it was our search or objectivity and a support among people who have no interest in the outcome of the question that led us to say, in our second report, that you would want, if something so important as a structural break entered this kind of analysis, to have that support come from outside the proceeding from disinterested sources.[331]

311. With respect to the statistical tests performed by Dr. Cicchetti, NERA commented that without the underlying economic theory, these statistical tests have a very limited explanatory power. When viewed in isolation, the statistical tests simply confirm that the TFP growth in a particular period was distinctly (i.e., "statistically significant") different from the TFP growth in other periods. The test does not, by itself, explain the reasons for such a difference and cannot prognosticate whether the TFP growth in any particular period is indicative of the changes in productivity likely to occur during the prospective PBR term.

312. The Commission agrees with NERA's view that a deviation from reliance on the longest period of available data requires support that a structural break in the industry has occurred. The Commission also agrees that the determination of whether a structural break has occurred demands the scrutiny of academic experts, peer review and testing by parties independent of the current proceeding.

313. NERA indicated that to the best of its knowledge, the only structural breaks discussed by scholars were the World Wars, the Great Crash in 1929 and the 1970s oil price shock.[332] The companies did not point to any external studies on this issue. In the absence of any independent academic studies examining the issue of structural breaks in the electric and gas distribution industries, the Commission is not prepared to accept the proposition that the long term underlying TFP trend of the industry had changed around the mid- or late1990s as implied by the companies' experts.[333]

314. With respect to the electric industry restructuring, the Commission observes that NERA used data only on the distribution portion of the sampled companies' businesses.[334] In the Commission's view, this approach sufficiently mitigates the concerns about the impact of industry restructuring on the TFP estimate. The Commission accepts NERA's view that electric industry restructuring did not necessarily lead to a change in the rate of growth of productivity for the distribution portion of the industry.[335]

315. Furthermore, the Commission is not persuaded by the companies' arguments that a more recent period provides a better indication of likely industry TFP during the PBR term. As further

331 Transcript, Volume 2, page 300, lines 8-22.
332 Exhibit 391.02, NERA second report, pages 15-16.
333 Exhibit 630.01, EPCOR argument, paragraph 49; Exhibit 98.02, Carpenter evidence, page 21; Exhibit 474.02, Frayer rebuttal evidence, page 19; Exhibit 110.01, Christensen Associates evidence, pages 11-12.
334 Exhibit 80.02, NERA report, page 6.
335 For example, Transcript, Volume 1, pages 109-111 (Dr. Makholm).

explained in Section 6.3.6 of this decision, because NERA used a volumetric output measure, the resulting TFP estimate is sensitive to economic recessions and upturns. In these circumstances, as PEG observed in its evidence, a company's productivity growth in one five or 10-year period may be very different from its productivity growth in the following five years, depending on what part of the business cycle the economy is in.[336] Dr. Lowry explained that the productivity of a company going into a recession (i.e., from peak to trough of a business cycle) may be very different from the productivity of the same company coming out of the recession when energy throughput is used as an output measure.[337]

316. In that regard, the Commission considers that Dr. Lowry's approach to determining the relevant time period to capture the entire business cycle in the sample period represents an improvement over the companies' approach of focusing on the most recent 10 to 15 years of data. However, PEG's method is also not entirely devoid of subjectivity, as judgement has to be applied as to what start and end points to use. For example, PEG offered that cooling degree days and the unemployment rate be used to select similar levels of a business cycle. Building on this logic, PEG recommended that recession years 2008 and 2009 be excluded from the analysis, because in this period the volumetric output indexes were extraordinarily depressed.[338] The gas companies did not agree with PEG's choice of start and end dates and submitted that this method resulted in biased and subjective estimates of TFP trends.[339] In AltaGas' view, it was vital that years 2008 and 2009 be included in the study to arrive at a balanced assessment of TFP.[340]

317. In the Commission's view, NERA's approach of using the longest time period available allows a smoothing out of the effects of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end points of a business cycle. Notably, the CCA seemed to reach a similar conclusion and indicated that if the years 2008 and 2009 were to be included in the study, the length of a sample period would have to be considerably longer than 10 to15 years and NERA's use of the full set of 1972 to 2009 data becomes reasonable, subject to certain other reservations about NERA's analysis.[341]

318. With respect to the argument that some other jurisdictions relied on a shorter time period for estimating TFP growth, the Commission notes that in many of those cases the period for a TFP study is driven by data limitations rather than a deliberate choice of the most relevant period for productivity calculations or is the result of settlement negotiations. This is especially true in the case of PBR plans based on efficiency frontiers and benchmarking studies which require a large amount of company-specific data for the selected group of peer companies. Dr. Cicchetti and Ms. Frayer noted that their observation of the other regulators' use of a 10-year period was more in the nature of a "rule of thumb."[342] The circumstances leading to the acceptance by other regulators of a sufficient TFP time period are varied and in the Commission's view do not suggest an accepted regulatory practice. This conclusion is reinforced by the differing views on the correct time period over which to conduct a TFP study reflected in the evidence of the various experts in this proceeding.

336 Exhibit 307.01, PEG evidence, page 23 and Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
337 Transcript, Volume 13, page 2503, line 9 to page 2504 line 1.
338 Exhibit 569.01, PEG rebuttal evidence (corrected), pages 7-9.
339 Exhibit 632, ATCO Gas argument, paragraph 77 and Exhibit 628, AltaGas argument, page 21.
340 Exhibit 650, AltaGas reply argument, page 18.
341 Exhibit 645, CCA reply argument, paragraph 38.
342 Transcript, Volume 11, page 2056, lines 10-15 and Volume 11, page 2115, lines 1-14.

319. In light of the above considerations, the Commission agrees with NERA's view that using the longest time period for which data are available is theoretically sound and represents the most objective basis for the TFP calculation. In the Commission's view, in the absence of any external scholarly studies pointing to a structural break in the TFP trend of the electric distribution industry, NERA's analysis based on a full 1972 to 2009 sample is the best indicator of the expected industry productivity growth during the PBR term. Moreover, such an approach eliminates the inevitable subjectivity involved in choosing a truncated time period for determining the industry TFP and mitigates the incentive to "cherry-pick" the start and end points to arrive at a desired TFP value.

320. In this respect, the Commission observes that PEG's preference for a 15-year sample period appeared to be primarily based on Dr. Lowry's personal judgement:

> Q. But what I'm trying to understand, though, Sir, the principles that you're applying in coming up with your period so that the subjectivity of picking the dates is reduced?
> A. Yes. Just based on my experience, you know, I used to think that you needed 10 years to smooth things out, and now I'm thinking more like 15. I don't know what more to say.[343]

321. The Commission recognizes that because PEG did not use a volumetric output measure, the resulting TFP may be less sensitive to the choice of start and end dates. As well, Dr. Lowry noted that the quality of data on the gas industry prior to 1996 was not good.[344] As such, the Commission acknowledges that it is uncertain whether having a longer time period for PEG's data would result in a different TFP measure. Nevertheless, in the Commission's view, PEG's approach to selecting the time period is more subjective than NERA's. Dr. Lowry acknowledged that if the Commission were to adopt his approach, the start and end dates of a sample period have to be reconsidered at the time of any PBR rebasing.[345]

6.3.3 The use of U.S. data and the sample of comparative companies in the TFP study

322. NERA's TFP study used a population of 72 U.S. electric and combination electric/gas companies. NERA noted that this population includes companies of different sizes and located in differed parts of the United States reflecting a wide diversity of geography, development and age.[346] PEG's study was based on a national sample of 34 U.S. gas distributors,[347] also with different operating characteristics.[348] In both studies, the sample size reflected the availability of reliable data for the U.S. companies in question.[349]

323. When questioned by the CCA on whether it is preferable to use a region-specific sample rather than a national sample, NERA's experts indicated that it is acceptable to base a TFP study on either all companies in an industry for which good data are available or to select a sub-sample

343 Transcript, Volume 13, page 2499, lines 5-10.
344 Transcript, Volume 13, page 2495, lines 14-16.
345 Transcript, Volume 13, page 2506, lines 7-9.
346 Exhibit 80.02, NERA report, page 4.
347 In its evidence, PEG also reported results of a subgroup of 7 Western U.S. companies (Exhibit 307.01, tables 1 and 2). However, as Dr. Lowry indicated, PEG did not base its recommendations on the Western subgroup analysis and it was included just as "another number for the Commission to use if they see fit" (Transcript, Volume 13, pages 2525-2527). Accordingly, the Commission did not discuss this part of PEG's evidence.
348 Exhibit 307.01, PEG evidence, pages 26-27.
349 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.

if the sub-sample is large enough to provide a reliable measure of productivity growth.[350] In that regard, Dr. Makholm pointed out that NERA's previous TFP study for Alberta from 2000[351] was based on a group of companies from the Western region. However, because the number of companies remaining in the Western region had declined since that time, NERA concluded that a TFP estimate based on this smaller group would give a less reliable, consistent and robust measure of productivity growth. As a result, NERA examined a national population of companies for its TFP analysis in this proceeding.[352]

324. The UCA indicated that NERA's sample of U.S. utilities is not comparable to Alberta gas and electric utilities in many respects. For example, the UCA noted that the NERA study sample contained companies that are unlike any Alberta distribution utility in terms of geography and climatic conditions. In addition, the UCA indicated that the U.S. utilities are subject to multiple different regulatory regimes with some operating under PBR and others under cost of service regimes. Further, the UCA pointed to differences in a number of other operational characteristics such as retail sales or number of employees between the companies in NERA's sample and Alberta utilities.[353]

325. In the UCA's opinion, it is critically important that the multiple differing regulatory, operational, organization and geographical circumstances of the companies included in the NERA sample be fully understood. Accordingly, the UCA argued that the companies included in the comparative group for Alberta utilities should be (i) unbundled, (ii) have some degree of comparability, and (iii) if possible, some should have been under PBR for quite some time.[354] Given the availability of historical data (1988 to 1997) for the distribution utilities in Ontario, the UCA argued that there is simply no need to use the U.S. data.[355]

326. In response to these criticisms, NERA explained that the purpose of the TFP study is not to explain productivity levels but instead productivity growth rates. In other words, NERA's study did not examine whether one company has a greater level of output for the same level of inputs than another. Rather, NERA looked at how the ratio of outputs to inputs changes over time. As such, the unique cost features of any particular company cancel out in the process.

327. Furthermore, NERA observed that the theoretical purpose of the X factor (to which the TFP study contributes) is not to find proxies for the companies to be regulated but rather to find the long-term, underlying industry productivity growth trend that firms would face in competitive markets. As such, a focus on finding companies just like those in Alberta would not accomplish this objective. Given the generally-perceived similarity of both the legal construct for utility regulation in Canada and the United States as well as the organization of the utility industries in the two countries, NERA maintained that using the U.S. data is warranted in this case.[356] Calgary and Fortis agreed with this approach.[357]

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350 Transcript, Volume 3, page 394, line19 to page 396, line 20.
351 Evidence of Jeff D. Makholm on behalf of UtiliCorp Networks Canada on its proposed PBR plan dated September 1, 2000 (Exhibit 195.01, AUC-NERA-5(a)).
352 Exhibit 391.02, NERA second report, paragraphs 45-46.
353 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 219-227.
354 Exhibit 634.02, UCA argument, paragraph 99.
355 Transcript, Volume 17, page 3219, lines 3-7 and page 3222, lines 1-16.
356 Exhibit 391.02, NERA second report, paragraphs 36-38.
357 Exhibit 629, Calgary argument, pages 23-24.

328. The other parties to this proceeding generally agreed with NERA's position on these issues. With respect to the study sample, EPCOR pointed out that the standard approach in North American PBR regulatory jurisdictions is to compare each company to the industry performance and not to specific peer groups.[358] Fortis also agreed with this approach, although Ms. Frayer expressed some concerns as to the applicability of the NERA study to Alberta companies.[359] The ATCO companies agreed with Dr. Makholm's opinion that a sample with fewer than 12 companies is too small to be representative of the industry TFP trends and supported NERA's approach of using the national population.[360]

329. Regarding the use of U.S. data, the CCA and the ATCO companies indicated that there are no suitable Canadian data available to make a reliable TFP estimate for the gas or electric distribution industries in Canada. Furthermore, even if suitable data were available, it is uncertain whether there are enough utilities in Canada to make a TFP estimate reliable given the small sample size it would be based upon.[361] Overall, the ATCO companies did not object to the use of the U.S. data, albeit subject to an adjustment for a productivity gap between the United States and Canadian economies, as further discussed in Section 6.4.2 of this decision.[362]

330. Similarly, Dr. Cicchetti on behalf of EPCOR noted that because of the differences between the United States and Alberta economies, the industry TFP trends that NERA estimated do not reflect economic conditions in Alberta. Nonetheless, Dr. Cicchetti concluded that NERA's U.S. data were a good starting point to use for the purposes of determining an X factor for EPCOR.[363] Ms. Frayer's preference was to consider relevant Canadian or Alberta utility data when available. However, in developing her recommendations for Fortis' X factor, Ms. Frayer used U.S. data and data from other jurisdictions, including the U.K., New Zealand and Australia.[364]

331. In the view of Dr. Schoech, it would be most desirable to look at the TFP growth for natural gas distribution companies that are most comparable to AltaGas in terms of their market context, in particular, the number of customers served and population density.[365] However, recognizing that there may not be historical data for utilities closely similar to AltaGas, the company's experts used broader sources of data to determine an appropriate historical estimate of TFP and to develop their proposal for the X factor. Specifically, in AltaGas' analysis, the results of the NERA's study were complemented with Statistics Canada's estimate of MFP trends in the gas distribution sector which also include water and other system utilities.[366]

332. AltaGas also took issue with PEG's study sample. First, AltaGas noted that PEG's productivity analysis was drawn from data representing less than half of the U.S. gas distribution industry. Second, in AltaGas' view, the selection of companies was biased, favouring larger service providers. And finally, AltaGas contended that it was unlikely that PEG's productivity study included any gas distributors with service territories and business contexts comparable to

358 Exhibit 630.02, EPCOR argument, paragraph 55.
359 Exhibit 633, Fortis argument, paragraph 91 and Exhibit 474.02, Frayer rebuttal evidence, pages 14-15.
360 Exhibit 631, ATCO Electric argument, paragraph 71; Exhibit 632, ATCO Gas argument, paragraph 78.
361 Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89.
362 Transcript, Volume 3, page 591, line 23 to page 592, line 3.
363 Exhibit 630.02, EPCOR argument, paragraph 59.
364 Exhibit 633, Fortis argument, paragraph 96.
365 Transcript, Volume 8, page 1417, line 12 to page 1418, line 9.
366 Exhibit 628, AltaGas argument, pages 22-23.

those of the company.[367] The latter concern was also raised by Dr. Carpenter, who noted that ATCO Gas has a customer density well below the average of PEG's sample.[368]

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333. As explained earlier in Section 6.2 of this decision, the UCA's approach to determining the X factor was based on an examination of the companies' efficiency or, in other words, whether one company has a greater level of output for the same level of inputs compared to other companies. The Commission explained that under this approach it is important to control for all the factors contributing to a firm's level of efficiency, since inadvertently leaving out an important productivity driver may invalidate the results of the study. In these circumstances, the search for companies with similar characteristics (location, size, geography, weather, consumption patterns, etc.) for the purposes of inclusion in the comparative group on which to base the productivity study becomes of paramount importance for the PBR plans based on efficiency benchmarking.

334. As set out in Section 6.2 above, the Commission does not accept the efficiency benchmarking approach for the purposes of PBR in Alberta because of the practical and theoretical problems associated with measuring efficiency levels.

335. Under the approach adopted by the Commission, the focus of the TFP study is on the industry productivity growth rate, not levels. As NERA explained, in this case the manifest differences between the companies in terms of their geographic areas and climatic conditions, operational characteristics, regulatory regime, size or any other consideration do not matter as much to the study as it only deals with the average of year to year changes in productivity growth. As such, the unique cost features of any particular company cancel out in the process.[369]

336. Indeed, the experience of Dr. Cronin and Mr. Motluk corroborates this conclusion. The UCA witnesses observed that the Ontario companies exhibited a similar productivity growth rate during the PBR term despite the inherent differences in age, past performance and investment needs.

> But what was remarkable about that performance was the near uniformity that the [local distribution companies] exhibited in engendering TFP of 1.2 percent per year. It didn't matter if they were large, medium, or small. It didn't matter if they had more aged infrastructure. It didn't matter if they were high growth or low growth. It didn't matter if they were high capital additions or low capital additions. What they did was they found a way to operate under the PBR for that period of time. This was again confirmed under the second variable [productivity factor] PBR in the first half of this decade.[370]

337. The Commission agrees with NERA's characterization that the TFP estimate that informs the X factor is supposed to reflect industry growth trends, not the trends in Alberta alone or among a group of companies with similar operations and cost levels to those in Alberta.[371]

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[367] Exhibit 628, AltaGas argument, pages 23-24.
[368] Exhibit 472.02, Carpenter rebuttal evidence, page 80.
[369] Exhibit 391.02, NERA second report, paragraph 37.
[370] Transcript, Volume 17, page 3183, line16 to page 3185, line 4; and see also at Transcript, Volume 17, page 3192, lines 16-20.
[371] Exhibit 391.02, NERA second report, paragraph 38.

338. In these circumstances, it is the Commission's view that when it comes to the sample size and the use of U.S. data in TFP studies, the relevant question to ask is not whether the companies in the sample are similar to the Alberta utilities, but: (i) whether the sample in the TFP study is reflective of the productivity trend in the U.S. power distribution industry, and (ii) whether the U.S. industry TFP trend represents a reasonable productivity trend estimate for the Alberta companies.

339. Regarding the first question, the Commission agrees with NERA, ATCO Electric and the CCA that a TFP study can be based on either all companies in the industry for which good data are available or on a sample of companies as long as this sample can provide a reliable, consistent and robust measure of industry productivity growth. The Commission observes that both NERA and PEG used data availability and data consistency as the primary criteria for including a particular company in their study sample.[372] Accordingly, the Commission does not consider that NERA's and PEG's sample selection is biased in any respect.

340. Furthermore, NERA pointed out that a study sample has to be large enough to provide robust estimates and did not recommend using a sample with fewer than 12 companies.[373] As noted earlier in this section, NERA's sample consisted of 72 companies of different sizes, reflecting a wide diversity of geography, development and age.[374] As well, PEG's study was based on a sample of 34 U.S. gas distributors.[375] The Commission considers these samples to be large enough and diversified enough to produce a TFP estimate that is reflective of the overall industry productivity growth.

341. With regard to the second question, the Commission notes that the need to use U.S. data in establishing productivity targets for Alberta regulated companies arose because of the lack of uniform and standardized data for Canadian electric and gas distribution utilities. As NERA and PEG pointed out, unlike in the United States, there is no Canadian central repository of public data due to the lack of standardized accounting across provinces with respect to utility operating reports.[376] Because of this data problem, regulators in Canada have used U.S. data. For example, the Ontario Energy Board, in several decisions, used U.S. data in establishing its PBR plans.[377]

342. Mindful of the existing Canadian data limitations, the Commission agrees with NERA, the CCA, the ATCO companies and EPCOR that given the generally perceived similarity of both the utility regulatory systems in Canada and the United States, as well as the organization of the utility industries in the two countries, the U.S. power distribution industry TFP growth trend is a reasonable starting point in establishing a productivity estimate for the Alberta companies.[378] This issue is further discussed in Section 6.4.2 of this decision dealing with the proposal for a productivity gap adjustment.

343. In light of the above considerations, the Commission finds NERA's and PEG's TFP study samples of 72 and 34 U.S. companies, respectively, to be acceptable, subject to the

372 Transcript, Volume 3, page 458, line 23 to page 459, line 3 and Volume 13, page 2528, lines 16-21.
373 Transcript, Volume 3, page 395, lines 12-24.
374 Exhibit 80.02, NERA report, page 4.
375 Exhibit 307.01, PEG evidence, page 26.
376 Transcript, Volume 2, page 290, lines 22-24; Exhibit 307.01, PEG evidence, page 25.
377 Exhibit 195.01, AUC-NERA-7 and Exhibit 634.02, UCA argument, paragraphs 110-111.
378 Exhibit 391.02, NERA second report, paragraph 36; Exhibit 636, CCA argument, paragraph 75; Exhibit 631, ATCO Electric argument, paragraph 80; Exhibit 632, ATCO Gas argument, paragraph 89; Exhibit 630.02, EPCOR argument, paragraph 59.

issues discussed below, as the starting point for a TFP analysis applicable to Alberta distribution utilities.

6.3.4 Importance of publicly available data and transparent methodology

344. In its September 8, 2010 letter to the parties, the Commission included the use of publicly available data and a transparent methodology as part of the requirements for NERA to meet in respect of its TFP study contributing to a PBR plan.[379]

345. NERA agreed with these requirements and pointed out that the extent to which PBR regulation transmits incentives to company management is critically dependent on the transparency, stability and objectivity of the formula that governs price movements between rate cases. In NERA's view, creating an index number for relative industry TFP with those attributes requires a high-quality transparent and uniform source of data that is readily available to the parties of regulatory proceedings. For this purpose, NERA used the data collected by the Federal Energy Regulatory Commission (FERC) for electric and combination electric/gas utilities on its Form 1 and other publicly available sources.[380] In NERA's view, the FERC Form 1 data are the only data that satisfy the criteria of transparency and objectivity for a large number of industry participants.[381]

346. NERA also expressed its opinion that transparency is the essential component of any analysis for the purpose of PBR plans. To this end, for each step of its analysis NERA documented the methodology and the data used to measure TFP. In addition, NERA's calculations and working papers, including any adjustments to the electronic dataset (such as for missing observations or rare but evident data anomalies) were made available for inspection and assessment by other parties.

347. All parties confirmed the importance of relying on publicly available data and transparent methodologies for the purpose of the TFP studies used in regulatory proceedings in order to make such studies objective and neutral.[382] In this respect, while no party questioned the transparency of NERA's methodology and the availability of FERC Form 1 data, parties to this proceeding took issue with PEG's productivity study over issues of objectivity and transparency.

348. With respect to transparency, ATCO Gas and AltaGas pointed out that PEG's study relied on a proprietary data which could not be fully tested in a public forum. Furthermore, these companies noted that even after examining PEG's working papers (made available under a confidential process), it was still unclear where individual data came from, as limited details were provided on the methods and sources used in the study.[383] Because of this lack of transparency in PEG's data and calculations, Dr. Carpenter indicated that he was not able to fully evaluate and replicate the results of PEG's TFP study.[384]

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[379] Exhibit 71.
[380] Exhibit 80.02, NERA report, pages 3-4 and Transcript, Volume 1, pages 55-57.
[381] Transcript, Volume 1, page 56, lines 6-14.
[382] Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 631, ATCO Electric argument, paragraph 73; Exhibit 632, ATCO Gas argument, paragraph 80; Exhibit 628, AltaGas argument, pages 24-25; Exhibit 645, CCA reply argument, paragraph 45.
[383] Exhibit 476.01, Carpenter rebuttal evidence, pages 74-77 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 36.
[384] Exhibit 476.01, Carpenter rebuttal evidence, page 77 and Transcript, Volume 6, page 1007, lines 7-15.

349. On the same subject, NERA observed that since there is no federal collection of universal and consistent data on the U.S. gas distributors similar to the FERC data set for the electric industry, statistical data from individual states must be used. Because of the varying data reporting requirements in different states, NERA cautioned that compilation of data from varying sources may not be consistent.[385]

350. The gas companies' concern regarding the lack of objectivity in PEG's study primarily related to the econometric model that Dr. Lowry and his colleagues used in addition to the index approach for estimating TFP. In particular, PEG regressed the TFP index for the 32 gas companies in its sample against the number of gas distribution customers, the number of electricity customers (for companies that provide both gas and electric service), the line miles and a time trend variable. Applying the obtained coefficients to the projected variables for Alberta gas companies, PEG came up with a TFP estimate customized for business conditions in Alberta.[386]

351. With regard to this method of TFP calculation, ATCO Gas' and AltaGas' experts pointed to a number of issues in the set-up of PEG's econometric model relating to the choice of explanatory variables, model specification, the interpretation of results, the presence of heteroskedasticity, etc.[387] NERA observed that an econometric estimation of TFP growth is unavoidably based on many judgments that are difficult for non-specialists to understand. In NERA's view, such econometric analyses are more suitable for the purpose of peer-reviewed scholarly research and not for setting the level of consumer prices in a PBR plan.[388]

352. To allay concerns about the use of proprietary data, PEG recalculated the TFP growth of the sample of gas distributors employing data that are entirely in the public domain. This resulted in a modest decrease in PEG's TFP number, from 1.32 per cent to 1.19 per cent. At the same time, PEG noted that although most of its data can be independently gathered from the public sources, it chose to purchase them from respected commercial vendors because of the higher quality and value added services that they provide.[389] In that regard, Dr. Lowry proposed that the value added by the commercial vendors in gathering and processing the data is well worth the restriction of a confidentiality agreement to permit their use in a regulatory proceeding.[390]

Commission findings

353. Because the parameters of the PBR formula will be used to determine customer rates in a contested regulatory process and those rates will be in place for a number of years, the significance of the objectivity, consistency, and transparency of the TFP analysis to be employed in calculating the X factor cannot be understated.[391] In this respect, the Commission observes that having extensively scrutinized and tested NERA's study, the companies were satisfied that

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385 Transcript, Volume 1, page 52, lines 16-22.
386 Exhibit 307.01, PEG evidence, page 33.
387 Exhibit 476.01, Carpenter rebuttal evidence, pages 83-84 and Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
388 Exhibit 391.02, NERA second report, paragraph 99.
389 Exhibit 478.01, PEG rebuttal, pages 20-21.
390 Transcript, Volume 13, pages 2456-2459.
391 Exhibit 391.02, NERA second report, paragraphs 95-96 and Exhibit 476.01, Carpenter rebuttal evidence, page 29.

NERA's TFP analysis complies with these criteria.[392] The Commission agrees. As Dr. Cicchetti commented on this issue:

> So my conclusion is NERA was objective and neutral as required to be by this Commission. It's also transparent in that you can see where the information came from. You can actually go back to the raw information to see if NERA made any mistakes in building the data set together and the like. And in that fashion I think they did exactly what the Commission asked and therefore I would use it as I did in my starting point.[393]

354. With respect to PEG's study, the Commission shares the gas companies' concerns that the TFP analysis of Dr. Lowry and his colleagues was not fully transparent and conducive to the detailed scrutiny by other experts or by the Commission.

355. While there is nothing inherently wrong with using proprietary data in regulatory proceedings, procedural fairness requires that parties must be provided with the opportunity of a fair hearing in which each party is given the opportunity to respond to the evidence against its position. This requirement clearly requires parties and the Commission to be able to fully understand, test and respond to the evidence filed in a proceeding. Further, the Commission has the obligation to provide reasons for its decisions. It can only do so if it is able to fully understand, test and analyze the evidence filed before it. Accordingly, fully transparent information is always preferable to information that requires the filing of motions for protection of confidential information and the execution of confidentiality agreements. It is also problematic if, in order to fully comprehend the confidential information, further explanations must be provided on the procedures used, assumptions made, judgment exercised and data adjustments made that produced the confidential evidence. In addition, as NERA observed, the problem with data that are not publicly available is that the research cannot be replicated. As well, there is a concern that such data will not be available at all or that only the original provider using the same assumptions, methodology and adjustments could be engaged to provide a consistent analysis when the parameters of the PBR regime are to be reset.[394]

356. The Commission agrees that it is highly desirable that any TFP analysis can be replicated by all willing parties to the proceeding. As Dr. Carpenter explained, until one has managed to replicate a piece of analysis, it is not possible to look for errors, adjust assumptions, and test for sensitivities.[395] In addition, as NERA pointed out, if Dr. Lowry and his colleagues at PEG are the only persons who are able to repeat the TFP analysis, the success of any future PBR plans will depend on PEG's participation.[396] For all of the above reasons, the Commission confirms its preference for a TFP study that relies on publicly available data.

357. The Commission's main concern with PEG's study relates to the overall lack of transparency with respect to data processing. The Commission accepts that because there is no central repository for data on the gas distribution industry, any researcher of this subject would be compelled to combine information from different sources, thus facing a problem of data consistency and uniformity.[397] However, to the extent that PEG compiled its dataset from a

392 Exhibit 632, ATCO Gas argument, paragraph 83; Exhibit 631, ATCO Electric argument, paragraph 76; Exhibit 630.02, EPCOR argument, paragraph 57; Exhibit 628, AltaGas argument, page 24.
393 Transcript, Volume 11, page 2017, lines 10-17.
394 Exhibit 391.02, NERA second report, paragraph 98.
395 Exhibit 476.01, Carpenter rebuttal evidence, page 82.
396 Transcript, Volume 1, page 56, lines 15-23.
397 Transcript, Volume 1, page 56, lines 6-14 and Volume 13, page 2467, lines 2-7.

number of sources (publicly available or not), it is of vital importance that all the steps and any adjustments to the data be clearly documented and explained. This would allow other experts to verify the accuracy of the data. As well, computation of the TFP estimate must be clearly explained. In this way, other parties to the proceeding can test and verify the calculations and, if necessary, replicate them in future proceedings. PEG's study did not satisfy these requirements.

358. For example, Dr. Lowry explained that PEG examined the dataset obtained from a commercial vendor and when necessary, made adjustments to the data to correct for any obvious anomalies:

> [...] not only does my staff do an initial screening and look for oddities to correct, to look for corrections, go make sure that that's what the form really said; but then it comes to me, and that's the final step is that I will go through very carefully and meticulously all the data and see if it squares with my expectations. And there will usually be 10 or 15 observations that need to be changed based on my second screening of the data.[398]

359. The Commission accepts that sometimes it may be necessary to adjust the raw data and in fact, NERA had to adjust its data as well. However, as Dr. Carpenter explained in his evidence, PEG did not clearly outline the adjustments it made.[399] In contrast, NERA made available for inspection and assessment by other parties any adjustments to the electronic dataset that it made as an integral part of its report.[400]

360. The importance of publicly available data and transparent methodology is demonstrated by the extent to which parties to this proceeding relied on NERA's working papers for developing their recommendations. For example, Dr. Cicchetti was able to estimate partial factor productivity (PFP) for EPCOR relying entirely on NERA's data.[401] As well, Dr. Cicchetti performed a number of statistical tests on productivity using company-level panel data.[402] Dr. Lowry, after scrutinizing NERA's working papers, suggested a number of corrections to NERA's study and was able to immediately quantify the impact of his recommendations on NERA's TFP estimate.[403]

361. If the parties had been using PEG's data, they would not have been able to engage in this type of detailed analysis without first executing a confidentiality agreement and working with PEG to understand all adjustments that were made to the vendor's data. For example, Dr. Carpenter pointed out that the output file that PEG provided included only summary results and did not provide the data for individual companies. As well, Dr. Carpenter pointed to the fact that PEG's computer code was written for a software package that was not commercially available.[404]

362. With respect to PEG's econometric model for TFP, the Commission agrees with NERA's explanation that the outcome of any regression model is highly dependent on the choice of explanatory variables, which represents the subjective judgment of the person conducting the analysis. As NERA explained:

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398 Transcript, Volume 13, page 2460, lines 4-12.
399 Exhibit 472.02, Carpenter rebuttal evidence, page 28.
400 Exhibit 80.02, NERA report, Appendix II.
401 Exhibit 103.05, Cicchetti evidence, pages 22-23.
402 Exhibit 473.07, Cicchetti rebuttal evidence, page 9.
403 Exhibit 478, PEG rebuttal evidence, Table 3 on page 12.
404 Exhibit 476.01, Carpenter rebuttal evidence, pages 74 and 77.

> DR. MAKHOLM: I was the first one to do that. I did the first decomposition of electric utility TFP numbers anywhere, and it's my thesis. I've done that. And if you go to the back of that, you'll see page after page after page of coefficients that depend on the specification that I chose, the number of things I decided to measure, the kind of dummy variables that I would use.
>
> And the results of those decompositions, as I call them, were dependent on my particular specification and what I judged to be useful at the time. I put it that -- to this group and to this Commission that those decisions of mine, which were useful for doing my thesis work, could have been done differently, and they could have changed the result of how we would predict the TFP growth should be for any region or size of company or any arbitrary company out there, and it could have been a lot different.[405]

363. Dr. Lowry also agreed that the exclusion of relevant variables biases the estimators and noted that PEG's analysis included "as many variables that matter as we can."[406] For example, PEG offered that a company's productivity growth is a function of the number of customers (gas and electric, if applicable), line miles and time.[407] However, in AltaGas' opinion, the model should also have included the volume of gas delivered, as variation in usage per customer also affects productivity.[408] Therefore, the Commission agrees with NERA's conclusion that econometric models are prone to the criticism of being less objective and too complex for the purposes of PBR plans.

364. In light of the above considerations, the Commission agrees with NERA, ATCO Gas and AltaGas that the lack of publicly available data and transparent methodology represent major drawbacks to the use of PEG's productivity analysis. In contrast, as noted earlier in this section, the Commission agrees with the companies that NERA's TFP study was transparent and objective.

6.3.5 Applicability of NERA's TFP study to Alberta gas distribution companies

365. The data used in NERA's study are for the distribution portion of the electric companies, whether standalone or combination electric/gas companies according to FERC Form 1. NERA indicated that its study did not include data for standalone gas companies, since it was not aware of a readily available data source that would permit a comparably transparent TFP study for standalone gas companies.[409]

366. In NERA's view, the productivity of gas and electricity companies is similar. For example, NERA observed that both electricity and natural gas distribution are highly capital intensive. Additionally, in some instances the electricity and gas distribution facilities share the same support structure.[410] During the hearing, Dr. Makholm noted that based on his personal knowledge of operations of gas and electric distribution industries, the institutional framework and regulatory and business requirements for the two sectors are quite similar. Accordingly,

405 Transcript, Volume 3, pages 475-476.
406 Transcript, Volume 13, page 2548, lines 14-22.
407 Exhibit 307.01, PEG evidence, page 33.
408 Exhibit 477, Christensen Associates rebuttal evidence, paragraph 46.
409 Exhibit 80.02, NERA report, pages 6-7.
410 Exhibit 80.02, NERA report, pages 6-7.

Dr. Makholm expressed his opinion that it is not necessary to differentiate the productivity growth for gas and electric distribution industries.[411]

367. Furthermore, NERA observed that according to data from Statistics Canada, TFP growth during the period 1972 to 2006 for Canadian electric power generation, transmission and distribution companies was 0.28 per cent while for natural gas distribution, water and other systems TFP growth was 0.21 per cent, using gross output as the output measure. Using value added as the measure of output, the numbers are 0.37 per cent for electric power generation, transmission and distribution companies and 0.34 per cent for natural gas distribution, water and other systems.[412] At the same time, Dr. Makholm cautioned that NERA's observation of the Statistics Canada indexes was merely a "relatively casual view" of a data source that NERA did not use in its study.[413] PEG, AltaGas and the ATCO companies also indicated that Statistics Canada's MFP indexes were subject to a number of reporting difficulties, as further discussed in Section 6.3.7 below.[414]

368. In light of the above considerations, NERA expressed its opinion that a specialized TFP study for gas distribution companies would not be a useful part of Alberta's PBR initiative, given the lack of uniform and objective data for a broad sample of gas companies that such a study would require to be a part of a transparent and objective PBR plan. Based on its familiarity with electricity and gas distribution and transmission businesses from a regulatory perspective, NERA concluded that a robust TFP study using FERC Form 1 data is a useful component of a PBR plan that applies to both the electricity and gas companies in Alberta.[415]

369. ATCO Gas and AltaGas noted that it would be preferable to base the X factor for gas companies on a study that measured TFP growth for the gas industry, if a study of sufficient transparency and quality were available. However, because the two gas companies rejected PEG's productivity study, they noted that no such study was available in this proceeding.[416]

370. In these circumstances, ATCO Gas expert Dr. Carpenter observed that in the absence of any compelling reason to distinguish between electric and gas companies, and having regard for the Statistics Canada figures that NERA cited in its report, it is reasonable to assume that the same TFP is appropriate for gas and electric utilities in Alberta.[417] Similarly, AltaGas noted that NERA's report, along with the examination of Statistics Canada MFP indexes, provides some evidence useful for estimating the TFP growth rate of Canadian gas distribution companies.[418]

371. In a similar vein, the CCA noted that since the gas and electric power distribution businesses have similarities (such as a gradual growth in rate base and the importance of customers as a cost driver), TFP research from one industry could be used to set a productivity estimate for firms in the other industry if data for both industries were unavailable. However, the CCA maintained that this was not the case in the present proceeding. In the CCA's view, PEG's analysis on U.S. gas distribution companies is suitable for the purpose of setting establishing a

[411] Transcript, Volume 1, pages 49-51.
[412] Exhibit 80.02, NERA report, page 7.
[413] Transcript, Volume 1, page 47, lines 4-6.
[414] Exhibit 307.01, PEG evidence, pages 41-43; Exhibit 99.01, Carpenter evidence, page 26; Exhibit 110.01, Christensen Associates evidence, paragraphs 43-44.
[415] Exhibit 80.02, NERA report, pages 4-5.
[416] Exhibit 632, ATCO Gas argument, pages 27-28 and Exhibit 628, AltaGas argument, page 25.
[417] Exhibit 99.01, Carpenter evidence, page 31.
[418] Exhibit 628, AltaGas argument, page 25.

TFP for Alberta gas utilities. In addition, the CCA noted that other studies of the TFP trends of Canadian gas distributors, prepared for disinterested parties such as the Ontario Energy Board and the Gaz Métro Task Force, could also be useful for the purpose of setting a gas distribution company TFP.[419] Calgary agreed that with the inclusion of PEG's TFP analysis, there are data on the record for both electric and gas companies and that the Commission's determination on TFP should reflect a range which includes both analyses.[420]

372. The UCA submitted that the range of its proposed X factor menu accommodates the TFP results of both NERA and PEG. Accordingly, the UCA argued that its X factor menu provides appropriate X factor choices for both electric and gas companies.[421]

Commission findings

373. Based on the evidence in this proceeding, and because of the similarities in the institutional framework, business environment and regulatory requirements between the gas and electric distribution industries, the Commission finds that TFP research from one industry can be used to estimate productivity growth for firms in the other industry when transparent and robust data for both industries are not available.

374. However, parties could not agree on whether the TFP estimates from PEG's study and various other studies on the productivity trends of Canadian and the U.S. gas distributors used by other regulators, as well as Statistics Canada's MFP indexes, represent a superior indicator of TFP for gas distribution companies as compared to the TFP estimate from NERA's study of the electric distribution industry.

375. As set out in Section 6.3.7 of this decision, because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. With respect to the TFP studies of Canadian gas distributors prepared for other regulators (such as the Ontario Energy Board and the Gaz Métro Task Force) that PEG discussed, the Commission considers that while this productivity research can provide a useful reference for determining the general reasonableness and direction of a productivity estimate for the gas distribution companies, these studies cannot be viewed as substitutes for NERA's TFP study.

376. In particular, PEG referenced the 1.07 per cent TFP estimate for Enbridge Gas Distribution and the 1.65 per cent TFP estimate for Union Gas over the period 2006 to 2010. PEG also referred to the 1.66 per cent average annual TFP growth of Gaz Métro over the period 2000 to 2009.[422] However, the Commission observes that these TFP estimates are company-specific (i.e., these studies measure each company's own historical productivity growth and not the TFP growth of the industry).[423] Relying on these TFP estimates is not consistent with the Commission's preferred approach to determining the X factor that is based on the average long term productivity growth of the industry, as set out in Section 6.2 above. As NERA explained, the theory behind this approach dictates that the purpose of a TFP study is to estimate the long-

419 Exhibit 636, CCA argument, paragraph 73.
420 Exhibit 629, Calgary argument, page 24.
421 Exhibit 634.02, UCA argument, paragraph 106.
422 Exhibit 307.01, PEG evidence, pages 40-41.
423 These reports were filed as Exhibit 376.03 (Gaz Métro) and Exhibit 376.04 (Union Gas Ltd. and Enbridge Gas Distribution Inc.).

term productivity growth of the industry, not the productivity growth of any particular company.[424]

377. PEG also referenced two TFP estimates with respect to the U.S. gas distribution industry. The first study found a TFP estimate of 1.18 per cent for the U.S. gas distribution industry over the period of 1999 to 2008, and the second study reported a TFP of 1.61 per cent over the period of 1994 to 2004.[425] In the Commission's view, differences in employed sample periods, input and output measures, as well as methodologies (e.g., indexing vs. econometric estimates), do not allow for a direct comparison of these numbers with NERA's TFP estimate.

378. Accordingly, the Commission finds that, in the absence of superior TFP data for the gas distribution industry, NERA's TFP study is an acceptable starting point for determining a productivity estimate for Alberta gas distribution companies.

6.3.6 Output measure in the TFP study

379. As set out in Section 6.3.1 above, productivity growth is specified as the difference between the growth rates of a firm's physical outputs and physical inputs.[426] Accordingly, the choice of an output measure directly affects the estimated TFP growth.

380. NERA indicated that its practice, both in this proceeding and in previous TFP growth analyses that it has undertaken, has been to use the sales volume, measured in kilowatt hours (kWh) as the measure of output. NERA recognized that it is possible to specify two or more outputs (such as kWh or numbers of customers) into a single output for measuring TFP. However, NERA stated its preference for kWh sales output measure, as the most representative of the nature of a company, the size of its system, and its revenues.[427]

381. At the same time, NERA accepted that this measure is not perfect and indicated that for the energy delivery business where much of the cost is tied up in long-lived capital, there are trade-offs in using one measure of output or another. For example, NERA pointed out that in a recession or in response to a price shock, kWh sales may decline with a distribution system that is otherwise unchanged, thereby seeming to show a decline in productivity growth. In that regard, NERA explained that its preference has always been to use kWh with the longest time series available so as to dampen the effects of the short-term or cyclical patterns that would most influence kWh sales as a measure of output.[428]

382. According to the CCA's experts, the correct output specification in a TFP study depends on the nature of the PBR plan. Specifically, PEG contended that volumetric output measures, such as the kWh sales used by NERA in its TFP study, are not correct in the context of revenue-per-customer cap plans. To arrive at this conclusion, Dr. Lowry of PEG showed that, if one accepts the belief that the costs of gas distributors are chiefly driven by the growth in the number of customers served, the mathematical logic of Divisia indexes dictates that the number of

424 Exhibit 391.02, NERA second report, paragraph 38.
425 Exhibit 307.01, PEG report, page 40 and Exhibit 366.04.
426 Exhibit 80.02, NERA report, page 5.
427 Exhibit 391.02, NERA second report, paragraph 47.
428 Exhibit 391.02, NERA second report, paragraph 47.

customers represents a relevant output measure to use in determining TFP as part of a PBR plan based on a revenue-per-customer cap.[429]

383. During the hearing, Dr. Lowry also explained that since under a revenue-per-customer cap plan, a company's revenues are driven by customer growth and are largely insensitive to the amount of energy sold, the number of customers is the relevant output measure to use for TFP studies used in a revenue-per-customer cap PBR plan. In contrast, under a price cap plan, a change in the amount of energy sold has an immediate effect on a company's revenues, and thus the use of a volumetric output measure is justified.[430] Accordingly, the CCA argued that output measures that place a heavy weight on volumetric and other usage should be used to determine the output index for TFP studies used in the context of a price cap PBR plan, while the number of customers should be used to determine the output index for TFP studies used in the context of a revenue-per-customer cap PBR plan.[431] NERA agreed with this logic.[432]

384. Furthermore, Dr. Lowry observed that in the presence of declining use per customer, a gas TFP study based on a volumetric output index would produce a lower productivity growth estimate compared to using the number of customers as an output measure.[433] Consequently, using a volumetric output measure in this instance would result in a TFP estimate and an X factor that are too low, lower than if the correct customer output measure had been used. This is because when usage per customer is falling, the rate of growth of customers will be greater than the rate of growth of energy transported. Therefore, the TFP growth rate, which is determined by subtracting the rate of growth of inputs from the rate of growth of outputs, will be greater when the correct customer output measure is used rather than the incorrect volumetric output measure.

385. In a similar vein, Mr. Johnson on behalf of Calgary noted that in the case of a gas company with declining use per customer, it is likely that under a price cap approach the I-X component would have to be higher than if it was applied to a revenue cap.[434] That is, if one assumes that the I factor remains unchanged, Mr. Johnson appeared to suggest that for a company experiencing the declining use per customer, the X factor will be lower under a price cap plan as compared to a revenue cap plan in order to generate the same revenue stream.

386. AltaGas' expert, Dr. Schoech, generally agreed with Dr. Lowry that in the presence of declining use per customer for gas distribution companies, the use of a volumetric output measure would result in a lower TFP growth rate than is reflective of actual productivity growth and some adjustment would be necessary to account for this fact if the TFP study were to be used for the gas distribution companies.[435] Since Dr. Schoech expressed his preference that the output measure should include both volumes and customers, he indicated that any adjustment to an X factor for a price cap to determine an X factor for a revenue-per-customer cap must apply only to the portion of the revenue requirement generated through the volumetric charges.[436]

429 Exhibit 307.01, PEG evidence, pages 16-17; Exhibit 610.03, Attachment to CCA undertaking; Exhibit 645, CCA reply argument, paragraphs 89-91.
430 Transcript, Volume 14, page 2871, line 25 to page 2872, line 11.
431 Exhibit 636, CCA argument, paragraph 113.
432 Exhibit 273.03, CCA-NERA-2(e).
433 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
434 Transcript, Volume 15, page 2926, line 23 to page 2927, line 8.
435 Transcript, Volume 8, page 1528, lines 12-17 and page 153, line 23 to page 1534, line 7.
436 Transcript, Volume 9, pages 1714-1715.

387. At the same time, Dr. Schoech pointed out that because both the NERA study and the Statistics Canada MFP measures base their output only on volumes, and not on both volumes and customers, the baseline for making this type of adjustment was not available.[437] Consequently, since the number of customers variable was not available for neither NERA's nor Statistics Canada's studies, AltaGas submitted that there is no basis for making an adjustment to the X factor to account for declining usage per customer.[438]

388. Similarly, Dr. Carpenter on behalf of the ATCO companies generally acknowledged that in the presence of declining use per customer, a volumetric output index employed in a gas utility TFP study produces a lower gas TFP growth rate compared to an output measure based on the number of customers.[439] However, Dr. Carpenter did not accept PEG's premise that the number of customers is a primary driver of the gas companies' costs.[440] With regard to the relevant output measure for a gas TFP study, Dr. Carpenter concluded that it is unclear whether the output index should be based on the number of customers, energy delivered, or a combination of the two.[441] Nevertheless, based on his examination of the record of this proceeding, Dr. Carpenter concluded that "the NERA output index is the best we have."[442]

389. ATCO Gas did not agree with Dr. Lowry's logic and submitted that the way in which TFP is measured should not depend on the use of the resulting estimate. As such, ATCO Gas argued that the determination of whether the TFP estimate should be made using the number of customers as the output measure or energy delivered as the output measure should not depend on what use is to be made of the resulting estimate.[443]

390. The experts of the other electric companies expressed some concerns with NERA's use of kWh as the measure of output. Dr. Cicchetti noted that any TFP study for electricity distribution should reflect the fact that activities associated with customer numbers are critical to the services that distributors provide, for example extending distribution networks to serve new customers, meter reading, service calls, etc. Accordingly, in Dr. Cicchetti's view, an output measure in a TFP study should include the number (and perhaps location) of customers that the companies serve.[444] A similar argument was put forward by IPCAA's and the UCA's experts who noted that using kWh as the only output measure does not accurately reflect the outputs the distribution company is providing.[445] In this case, Dr. Cicchetti explained that because in the electric distribution industry the usage per customer is growing, not declining, the rate of growth of customers will be smaller than the rate of growth of energy throughput.[446] Accordingly, Dr. Cicchetti's, IPCAA's and the UCA' recommendations on output measure would result in a lower TFP and a lower X for electric companies.

391. Ms. Frayer noted that the use of a single output measure will make the resulting TFP estimate more volatile, as demonstrated by the year-to-year results in NERA's report. In

437 Transcript, Volume 8, page 1534, lines 9-17.
438 Exhibit 628, AltaGas argument, page 36.
439 Transcript, Volume 6, page 979, lines 20-24.
440 Transcript, Volume 6, page 983, lines 3-11.
441 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
442 Transcript, Volume 6, page 981, lines 1-2.
443 Exhibit 632.01, ATCO Gas argument, pages 21-27.
444 Exhibit 103.05, Cicchetti evidence, pages 13-14.
445 Exhibit 306.01, Vidya Knowledge Systems evidence, pages 4-5; Exhibit 299.02, Cronin and Motluk UCA evidence, page 235.
446 Exhibit 103.05, Cicchetti evidence, page 14.

Ms. Frayer's view, using more than one output measure would smooth out this volatility and produce a more stable output index that is more consistent with the multi-dimensional service that the distribution companies provide.[447]

Commission findings

392. The Commission agrees with the experts in this proceeding that each possible output measure (for example, energy sales, number of customers, line miles, peak usage, etc.) or combination thereof has its own merits and disadvantages.[448] However, the Commission agrees with NERA's and PEG's view that when selecting a particular output measure, it must be matched to the type (price cap or revenue-per-customer cap) of a PBR plan.[449]

393. As discussed in Section 4 of this decision, the Commission recognizes that the rate designs of the gas distribution companies do not entirely reflect their cost drivers. While a large proportion of gas distributors' costs are fixed, a significant portion of these costs is recovered through variable charges. Also, as discussed in Section 4, both AltaGas and ATCO Gas are experiencing a declining use per customer. In these circumstances, a decline in use per customer would lead to a decrease in the companies' revenues that would not be offset by a decrease in costs. As a result of these considerations, the Commission is approving PBR plans in the form of a revenue-per-customer cap for ATCO Gas and AltaGas.

394. The experts in this proceeding explained that by focusing on revenue per customer as opposed to prices per unit of gas delivered, the revenue-per-customer cap plan effectively shields the revenue of gas companies from variations in energy use per customer.[450] In these circumstances, Dr. Schoech[451] on behalf of AltaGas and Dr. Cicchetti[452] on behalf of EPCOR acknowledged that the number of customers, not the volumes sold, becomes the driver of a company's revenues.[453] The Commission agrees with Dr. Lowry and his colleagues at PEG that for revenue-per-customer cap plans, the number of customers, rather than a volumetric output measure, is the correct output measure for a TFP study.

395. Using similar logic, the Commission agrees with Dr. Lowry that output measures that place a heavy weight on volumetric and other usage measures should be used for TFP studies that are part of a price cap PBR plan.[454] Therefore, the Commission considers that kWh sold output measure used by NERA in its TFP study remains an acceptable output measure to use for the purpose of the price cap PBR plans approved for ATCO Electric, Fortis and EPCOR.

396. The Commission acknowledges the concerns of Fortis, EPCOR, IPCAA and the UCA that a single output measure such as kWh may not capture all of the outputs that an electric distribution company provides. However, as the Commission observed earlier in this section, a consensus on the best measures to use has not been reached, with different experts offering different measures. For example, Dr. Cronin noted that the most relevant output measure is the

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447 Exhibit 474.02, Frayer rebuttal evidence, page 16.
448 Exhibit 391.02, NERA second report, paragraph 47.
449 Exhibit 307.01, PEG evidence, page 12; Exhibit 273.03, CCA-NERA-2(e).
450 Exhibit 100.02, Frayer evidence, page 23; Transcript, Volume 6, page 986, lines 9-13; Transcript, Volume 14, pages 2871-2872.
451 Transcript, Volume 9, pages 1714-1715.
452 Transcript, Volume 11, page 2070, lines 3-6.
453 Transcript, Volume 9, page 1714, lines 8-18.
454 Transcript, Volume 14, 2872 lines 4-7.

number of customers.[455] In Dr. Cicchetti's[456] and Ms. Frayer's[457] view, both megawatt hours and the number of customers have to be considered. Dr. Carpenter concluded that it is unclear whether the output measure should be based on the number of customers, energy delivered, or a combination of the two.[458] Dr. Lowry preferred energy delivered.[459] In light of this uncertainty, the Commission is not persuaded that NERA's output measure of kWh sold is an inferior output measure compared to the variety of alternatives proposed.

397. With respect to Ms. Frayer's concern that the use of a single output measure based on energy volumes will make the resulting TFP estimate more volatile, the Commission agrees with NERA that using kWh with the longest time series available will mitigate such volatility.[460] Overall, the Commission agrees with Dr. Carpenter's view that NERA's output index measuring kWh sold is an acceptable measure to use for the purpose of calculating TFP growth for electric distribution companies.

6.3.7 Other productivity indexes

398. In addition to the two TFP studies performed by NERA and PEG, ATCO's, Fortis' and AltaGas' experts relied on the various MFP indexes published by Statistics Canada and academic publications examining productivity in different sectors of the U.S. and Canadian economies. In developing their productivity target recommendations, the experts of Fortis and AltaGas examined the Statistics Canada MFP indexes for the utilities industry. However, Ms. Frayer and Dr. Schoech acknowledged that the use of these indexes may be problematic for establishing the TFP for electric and gas distribution companies because, for the purposes of the Statistics Canada MFP index, electric distribution is combined with power generation and transmission. Natural gas distribution is combined with water, sewage and other systems.[461]

399. Because of the presence of these items not pertaining to electric distribution, Ms. Frayer's preference was to rely on the Statistics Canada MFP for the utilities sector in general, not the more specific index for electric utilities.[462] Similarly, Dr. Schoech and his colleagues observed that the Statistics Canada MFP for the natural gas and water subsector showed some "significant structural anomalies" and also considered data for the utilities sector in general.[463]

400. The CCA's experts pointed out that the Statistics Canada MFP indexes have several problems that limit their usefulness in this proceeding. First of all, PEG noted that the inclusion of power generation and transmission in the electric sector and the inclusion of water systems in the gas sector substantially reduces the relevance of Statistics Canada's MFP indexes for the electric and gas distribution companies. Second, PEG highlighted the fact that the output of the industry is measured volumetrically and thus may not be an accurate reflection of gas sector productivity growth, as discussed earlier in Section 6.3.6 of this decision. In addition, PEG also expressed a number of other concerns with Statistics Canada's MFP indexes, including the influence of large conservation programs in several Canadian provinces not experienced in

455 Transcript, Volume 17, page 3236, lines 6-8.
456 Transcript, Volume 11, page 2070, lines 1-2.
457 Transcript, Volume 11, pages 2108-2109.
458 Exhibit 472.02, Carpenter rebuttal evidence, page 32.
459 Exhibit 307.01, PEG evidence, page 36.
460 Exhibit 391.02, NERA second report, paragraph 47.
461 Exhibit 110.01, Christensen Associates evidence, paragraph 43; Exhibit 100.02, Frayer evidence, pages 58-66.
462 Exhibit 100.02, Frayer evidence, pages 65-66.
463 Exhibit 110.01, Christensen Associates evidence, paragraphs 44 and 47.

Alberta, the effect of the recent economic recession and the use of value added indexes which ignores the productivity of intermediate inputs.[464]

401. Ms. Frayer[465] and Dr. Carpenter[466] also examined the study of productivity trends at the provincial level prepared by the Center for the Study of Living Standards (CSLS).[467] As Ms. Frayer explained, the CSLS report "provides an analysis of the economic conditions and productivity of ten Canadian provinces over a ten-year period from 1998 to 2007."[468] Ms. Frayer observed that this report used the same methodology and underlying data that Statistics Canada employed in the calculation of its MFP indexes. As a result, Ms. Frayer noted that the CSLS productivity indexes do not differ substantially from the MFP indexes published by Statistics Canada.[469]

402. Because of the similarities between the Statistics Canada and the CSLS analyses, the CCA indicated that its concerns with respect to the Statistics Canada MFP indexes equally apply to the CSLS estimates. Additionally, PEG indicated that in correspondence with the authors of the CSLS study, the authors "conceded that the study used an experimental methodology and is not of a high enough standard to be used in X factor determination."[470]

403. Finally, for this proceeding Ms. Frayer also updated her TFP study performed for the Ontario Energy Board in 2007. Ms. Frayer's updated study covered 78 local distribution companies in Ontario for the period 2002 to 2009 and found negative TFP growth in the range of -0.4 per cent to -1.5 per cent.[471]

404. PEG expressed its concerns with this study primarily relating to methodology and the short sample period. With respect to methodology, PEG took issue with Ms. Frayer's use of line miles as a proxy for the capital quantity trend. The UCA echoed this concern.[472] In addition, PEG noted that Ms. Frayer's sample period was "far too short" to smooth out the effects of annual variations in productivity growth arising from the use of volatile output measures such as energy volumes and peak demand.[473]

Commission findings

405. The Commission agrees with the CCA's experts that because the Statistics Canada MFP indexes include power generation and transmission in the electric sector and water systems in the natural gas sector, these indexes are not suitable for estimating the TFP for distribution companies. The Commission does not share Ms. Frayer's view that looking at a more aggregated MFP index for the utilities sector in general would help to address this problem. As the CCA

464 Exhibit 307.01, PEG evidence, pages 41-43.
465 Exhibit 100.02, Frayer evidence, page 58.
466 Exhibit 98.02, Carpenter evidence, page 33, A74.
467 The Center for the Study of Living Standards, *New Estimates of Labour, Capital, and Multifactor Productivity Growth and Levels for Canadian Provinces at the three-digit NAICS Level, 1997-2007*, issued on June 8, 2010.
468 Exhibit 100.02, Frayer evidence, page 66.
469 Exhibit 100.02, Frayer evidence, pages 66-68.
470 Exhibit 307.01, PEG evidence, pages 43-44 and Exhibit 376.01, ATCO-CCA-57(b).
471 Exhibit 100.02, Frayer evidence, pages 72-76.
472 Exhibit 299.02, Cronin and Motluk UCA evidence, page 81.
473 Exhibit 645, CCA reply argument, pages 32-33.

explained, such an aggregate index still includes such items as generation, transmission and water systems, which further dilutes the productivity trend of the distribution component.[474]

406. In addition, PEG observed that Statistics Canada uses volumetric output measures for calculating its MFP indexes.[475] As mentioned in Section 6.3.6 above, Dr. Lowry explained that in the presence of a declining use per customer experienced by the gas distribution industry, a gas TFP study based on a volumetric output index will understate the productivity of the gas industry.[476]

407. As Ms. Frayer observed, the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes. Accordingly, the Commission considers that this study is prone to the same criticisms as the Statistics Canada indexes. Overall, the Commission considers that while Statistics Canada's MFP indexes and the CSLS report can be a useful reference for gauging the general productivity trends of the utilities sector, these analyses cannot be a substitute for a TFP study for either the electric or gas distribution industries.

408. With respect to Ms. Frayer's updated study on Ontario distribution companies, the Commission shares the CCA's concern that the short period covered by the study (2002 to 2009) does not allow measuring the long-term industry productivity trend. As the Commission observed in Section 6.3.2 of this decision, most experts in this proceeding agreed that a period of less than 10 years will not achieve this purpose.[477] Furthermore, the Commission is not persuaded that a TFP study based exclusively on Ontario distribution companies represents a better indicator of the underlying industry productivity trend for the electric or gas distribution industries compared to NERA's study covering a broad sample of companies from across the United States.

6.3.8 Commission determinations on TFP

409. There are two productivity studies on the record in this proceeding. The first, conducted by NERA, calculated a TFP of 0.96 per cent.[478] This TFP value was based on an analysis of the distribution portion of 72 U.S. electric and combination electric/gas companies over the period of 1972 to 2009.[479] The second study was conducted by PEG on behalf of the CCA for the gas distribution industry and found a TFP in the range of 1.32 to 1.69 per cent. PEG's study examined 34 U.S. gas distribution companies over the period of 1996 to 2009.[480]

410. The ATCO companies, Fortis and AltaGas relied on the various MFP indexes published by Statistics Canada as well as the CSLS study examining productivity in different sectors of the U.S. and Canadian economies for a variety of purposes.[481] As explained in Section 6.3.7 above,

474 Exhibit 645, CCA reply argument, paragraph 113.
475 Exhibit 307.01, PEG evidence, page 42.
476 Transcript, Volume 14, page 2872, line 20 to page 2873, line 4.
477 Exhibit 307.01, PEG evidence, page 28; Exhibit 631, ATCO Electric argument, paragraphs 61-62; Exhibit 632, ATCO Gas argument, paragraphs 69-70.
478 In its first report NERA estimated a TFP of 0.85 per cent. However, in its second report it accepted one of the adjustments proposed by PEG (related to labour quantity estimation for the period 2002 to 2009). This adjustment resulted in a recalculated TFP estimate of 0.96 per cent.
479 Exhibit 391.02, NERA second report, Table 3.
480 Exhibit 307.01, PEG evidence, page 2.
481 Exhibit 98.02, Carpenter evidence, paragraph 43; Exhibit 100.02, Frayer evidence, page 58; Exhibit 110.01, Christensen Associates evidence, paragraph 43.

the Commission determined that the MFP indexes published by Statistics Canada as well as the CSLS study are unsuitable for determining TFP for either the electric or gas distribution industries.

411. The Commission has evaluated the NERA and PEG TFP studies with respect to a number of issues and criteria discussed by the parties, such as the relevant time period and sample size, the relevance of the U.S. data to Alberta companies, the use of publicly available data and transparent methodology, and the applicability of the obtained TFP number to both gas and electric companies as set out in sections 6.3.2 to 6.3.6 of this decision. Based on this evaluation, the Commission finds that NERA's study is preferable to use in this proceeding given the objectivity and transparency of the data and of the methodology used, the use of data over the longest time period available and the broad based inclusion of electric distribution companies from the United States.

412. In the Commission's view, NERA's study was more objective and transparent compared to PEG's analysis. First, as the Commission observed in Section 6.3.2 above, the choice of a sample period in PEG's study was primarily based on Dr. Lowry's personal judgment, not on objective criteria. Moreover, as set out in Section 6.3.4, PEG's lack of transparency in data processing did not allow either the other parties nor the independent consultant NERA, to fully test and verify its TFP recommendation. As such, while the Commission recognizes the value of a separate productivity study focusing on gas distributors, the drawbacks of PEG's TFP research do not allow the Commission to rely on it.

413. The Commission notes that in addition to the issues discussed in sections 6.3.2 to 6.3.7 above, PEG expressed a number of other concerns with NERA's study relating to the correct index form and the capital quantity index to use, among others.[482] Some of these issues reflect an ongoing academic debate on which consensus has not been reached, or for which there is no right or wrong answer. For instance, PEG advocated the use of a chain-weighted form of a Tornqvist-Theil index, while NERA preferred the use of a multilateral Tornqvist-Theil index.[483] Similarly, PEG indicated that the correct capital quantity measure to use should be the inflation-adjusted value of gross plant, while NERA insisted on using the net plant value.[484] Overall, the Commission considers that PEG's criticisms do not undermine the credibility of NERA's TFP study.

414. The Commission also observes that all of the companies' experts used NERA's study as a starting point for their X factor recommendations despite expressing some reservations about particular aspects of the study and offering various adjustments primarily relating to the sample period.[485]

415. In light of the above considerations, the Commission accepts NERA's methodology and finds that NERA's TFP estimate of 0.96 per cent represents a reasonable starting point for setting an X factor for the Alberta companies. Accordingly, based on NERA's study, the Commission

482 Exhibit 569.01, PEG rebuttal evidence, redlined pages; Exhibit 478, PEG rebuttal evidence, pages 11-17; Exhibit 609.02, CCA undertaking response: PEG adjustments to NERA.
483 Transcript, Volume 1, pages 76-77.
484 Transcript, Volume 1, pages 74-75 and Exhibit 461.02, AUC-NERA-16.
485 Exhibit 103.05, Cicchetti evidence, page 16; Exhibit 98.02, Carpenter evidence, page 32; Exhibit 100.02, Frayer evidence, page 79; Exhibit 110.01, Christensen Associates evidence, page 15.

finds that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric distribution companies.

416. With respect to the gas companies, as discussed in Section 6.3.6 above, the Commission agrees with Dr. Lowry's argument that it is necessary to match the output measure to the type of PBR plan (price cap or revenue-per-customer cap).[486] However, in the absence of a reliable and transparent TFP study on the gas distribution industry and information on how changes in the relevant output measures and input measures for electric and gas distribution industries compare to each other over the 1972 to 2009 study period, the Commission is not prepared to make any adjustment to NERA's TFP estimate in order to obtain a TFP estimate for the gas distribution companies.

417. The Commission observes that NERA, ATCO Gas and AltaGas agreed that NERA's study represents a reasonable starting point for determining the TFP trend for gas distributors.[487] The Commission agrees. Accordingly, the Commission finds that NERA's TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the gas distribution companies.

6.4 Adjustments to arrive at the X factor

418. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment if an output-based measure is used for the I factor.[488] Additionally, Dr. Carpenter on behalf of the ATCO companies,[489] Dr. Cicchetti on behalf of EPCOR,[490] and Dr. Schoech on behalf of AltaGas[491] expressed their views that NERA's TFP analysis based on the U.S. data needed to be adjusted for the differences in the economy-wide productivity growth between the United States, Canada and Alberta.

419. In addition to the above adjustments, parties discussed whether the companies' proposals to exclude all of or part of capital from the I-X mechanism should have any effect on the X factor. Each of these possible adjustments is addressed in the following sections of this decision.

6.4.1 Input price and productivity differential if an output-based measure is chosen for the I factor

420. Similar to the discussion in Decision 2009-035 dealing with ENMAX's FBR plan,[492] parties to this proceeding pointed out that the choice of an I factor can influence the X factor depending on the productivity that may be embedded in a particular inflation measure.

421. As Dr. Carpenter and Ms Frayer explained, there are two types of inflation measures that can be used for the I factor: input-based and output-based. Input-based measures reflect the change in the prices of goods and services purchased as inputs into the companies' production

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486 Exhibit 307.01, PEG evidence, page 12.
487 Exhibit 80.02, NERA report, pages 4 and 5; Exhibit 99.01, Carpenter evidence, page 31; Exhibit 628, AltaGas argument, page 25
488 Exhibit 461.02, AUC-NERA-17(a) and (b).
489 Exhibit 98.02, Carpenter evidence, pages 26-34.
490 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
491 Transcript, Volume 8, page 1414, lines 9-25.
492 Decision 2009-035, paragraphs 126-128.

process. A labour cost index such as AWE or AHE represents an example of an input price index since they track the changes in the wages and salaries of company's employees and contracted labour services. In contrast, output-based measures reflect the change in the prices of the basket of goods and services that are outputs of the economy and are typically purchased by final consumers rather than by companies as inputs. The CPI (consumer price index) would usually be an example of this type of measure.[493]

422. Given that the purpose of the I factor in a PBR plan is to track the prices of the inputs used by the electric or gas distribution industries (and therefore, the companies), the use of an input-based price index is preferred. However, on many occasions, the desired input price index may not be readily available or may not exist at all.[494] As a result, PBR plans may need to use output-based measures that are readily available, widely known and easy to explain to consumers, stakeholders and regulators.[495] NERA pointed out that the CPI is the most common inflation measure in PBR plans in Canada, while the GDP price index (also an output-based measure) is dominant in the United States.[496]

423. Nevertheless, using an output-based inflation index in a PBR plan may be problematic. Because the measure of output inflation already incorporates the effects of economy-wide productivity gains, such an index would not necessarily be indicative of the input price inflation likely to be experienced by the industry and, accordingly, the companies during the plan term. As a result, it may be necessary to adjust the TFP estimate when determining the X factor to correct for the difference between the output inflation included in the inflation factor and the industry input inflation.[497]

424. NERA and Dr. Carpenter explained that for practical purposes this adjustment consists of two adjustments to TFP to arrive at the X factor: a productivity differential and an input price differential.[498] In its evidence, PEG explained the logic behind those two adjustments as follows:

> The productivity differential is the difference between the MFP trends of the industry and the economy. The X will be larger, slowing the [I-X index] growth, to the extent that the MFP growth of the economy is slow. The input price differential is the difference between the input price trends of the economy and the industry. X will be larger (smaller) to the extent that the input price trend of the economy is more (less) rapid than that of the industry.[499]

425. As Fortis' expert pointed out, in this case an X factor based on TFP with these two adjustments may be interpreted as the difference between the productivity growth rate of the industry and the productivity growth rate included in the output inflation measure used. On the other hand, if an input price index is used for the I factor, no adjustment to TFP is required. In this case, the resulting X factor would reflect the productivity growth of the industry.[500]

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493 Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 33.
494 Exhibit 476.01, Carpenter rebuttal evidence, page 67.
495 Exhibit 100.02, Frayer evidence, pages 33-34.
496 Exhibit 391.02, NERA second report, paragraph 65.
497 Exhibit 476.01, Carpenter rebuttal evidence, page 67; Exhibit 100.02, Frayer evidence, page 54; Exhibit 628, AltaGas argument, pages 12-13.
498 Exhibit 461.02, AUC-NERA-17(b) and Exhibit 476.01, Carpenter rebuttal evidence, page 67.
499 Exhibit 307.01, PEG evidence, pages 20-21.
500 Exhibit 100.02, Frayer evidence, page 52.

Commission findings

426. The interaction between the I factor and the X factor described above is based on a well-established theoretical foundation, as demonstrated by the agreement of parties on the need to adjust TFP in determining an X factor if an output-based inflation measure is chosen for the purpose of the PBR plan.[501] Consequently, the parties advised that, when possible, it is preferable to use input-based price indexes for the I factor of the PBR plan, since using such indexes avoids the need for an input price differential and a productivity differential adjustment to TFP.

427. As set out in Section 5 of this decision, the Commission approved a composite I factor consisting of AWE and CPI indexes for Alberta. While the AWE index represents an example of an input-based measure, the CPI is generally regarded as an output rather an in input price index. However, as the Commission explained in Section 5.2.3 above, in the context of this proceeding, the Alberta CPI will be used only to monitor price trends for the companies' non-labour inputs. EPCOR, AltaGas and ATCO Gas submitted that because the Alberta CPI is a good proxy for the price changes for that particular group of expenditures, it may be considered an input price index for the purpose of their composite I factors.[502] The Commission agrees.

428. Accordingly, since both components of the approved I factors can be considered input-based price indexes, there is no need in this case for the Commission to consider an adjustment to TFP for an input price differential or productivity differential in the calculation of the X factor.

6.4.2 Productivity gap adjustment

429. As discussed in Section 6.3.1 above, NERA's study used a population of 72 U.S. electric and combination electric/gas companies. In these circumstances, Dr. Carpenter indicated that to the extent that utilities in Canada have different productivity expectations than utilities in the U.S., an adjustment to the NERA's TFP number would be required in a Canadian PBR context.[503]

430. Dr. Carpenter observed that there is a well-documented productivity gap between the Canadian and the U.S. economies, with Canadian productivity growth rates consistently lower than productivity growth in the U.S. For example, Dr. Carpenter pointed to a Statistics Canada study that found that average annual MFP growth was 0.9 percentage points lower in Canada than in the United States from 1961 to 2008.[504] In addition, Dr. Carpenter observed that in its TFP analysis, NERA showed that on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period.[505]

431. At the same time, the ATCO companies' expert acknowledged that while the existence of the economy-wide productivity gap has been documented by government statistics and academic studies, the specific causes of the gap are not well understood and it is not clear whether a similar

501 Transcript, Volume 1, pages 141-142; Transcript, Volume 4, pages 611-612; Transcript, Volume 8, page 1415; Transcript, Volume 11, pages 2133-2134; Transcript, Volume 13, page 2589.

502 Exhibit 630.02, EPCOR argument, paragraph 31; Exhibit 628, AltaGas argument, pages 12-13; Exhibit 648.02, ATCO Gas reply argument, paragraph 94.

503 Exhibit 98.02, Carpenter evidence, pages 25-26.

504 Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009.

505 Exhibit 98.02, Carpenter evidence, page 29.

productivity gap exists in the electric and gas utility sector. For example, Dr. Carpenter noted that studies relying on the Statistics Canada data typically define the utility sector more broadly, including power generation and transmission in the electric sector and water and sewage utilities in the gas sector.[506] Thus, these studies may not provide an accurate estimate of productivity growth for electric or gas distribution companies. As a result, Dr. Carpenter conceded that there is no evidence to permit a direct comparison of Canadian and U.S. productivity growth rates for electric or gas distribution companies.[507]

432. Despite the lack of direct empirical evidence, Dr. Carpenter concluded that it is likely that the economy-wide productivity gap between Canada and the U.S. persists at the utility sector level. Dr. Carpenter arrived at this conclusion as a result of following considerations.[508]

- First, Dr. Carpenter indicated that he was not aware of any evidence that differences in the composition of the two economies drive the different rates of productivity growth. For example, Dr. Carpenter noted that the proportion of total GDP generated by the various sectors of the Canadian and the U.S. economies is not very different.
- Second, Dr. Carpenter noted that he was not aware of any compelling evidence that there is one sector or a group of sectors in the Canadian and the US economies that drives the productivity gap. According to Dr. Carpenter, there is evidence that the productivity gap occurs in a wide range of sectors, which is likely to include the utility sector.
- Third, Dr. Carpenter observed that while there is some disagreement among researchers as to the possible explanations for the U.S.-Canada gap, he had seen no reason to believe that the productivity gap is unlikely to affect the utility sector.

433. As a result of these considerations, Dr. Carpenter indicated that NERA's TFP estimate for the U.S. companies needed to be adjusted for the observed U.S.-Canada productivity gap. Using the economy-wide productivity estimates from Statistics Canada and the U.S. Bureau of Labour Statistics presented in NERA's report, Dr. Carpenter proposed an adjustment of approximately -1.5 percentage points to NERA's TFP.[509]

434. Furthermore, Dr. Carpenter expressed his view that the recommended productivity gap adjustment was conservative for Alberta. The ATCO companies' expert noted that the CSLS report[510] and another productivity study[511] show a Canada-Alberta productivity gap, with Alberta having slower productivity growth in the utility sector and in the business sector in general. However, because ATCO Electric and ATCO Gas make up a significant part of the utility sector in Alberta, Dr. Carpenter indicated that adjustment for a Canada-Alberta productivity gap may not be appropriate since the resulting X factor would be "ATCO-specific" rather than reflective of the industry productivity trends.[512]

435. AltaGas agreed with Dr. Carpenter that in the case that the TFP analysis "did not focus on the Canadian gas distribution industry, an adjustment for the U.S.-Canada productivity gap

506 Transcript, Volume 6, page 1004, lines 4-25.
507 Exhibit 98.02, Carpenter evidence, pages 26-27.
508 Exhibit 98.02, Carpenter evidence, pages 27-29.
509 Exhibit 98.02, Carpenter evidence, page 30, Tables 2 and 3.
510 The CSLS report was discussed in Section 6.3.7 of this decision.
511 Rao, Someshwar, Andrew Sharpe and Jeremy Smith, *An Analysis of the Labour Productivity Growth Slowdown in Canada since 2000*, International Productivity Monitor, Spring 2005.
512 Exhibit 98.02, Carpenter evidence, pages 33-34.

would generally be appropriate.[513] With respect to the Canada-Alberta productivity gap, AltaGas observed that the CSLS report (from which the existence of such a gap was inferred) was conducted on an experimental basis. As such, AltaGas did not propose to make an adjustment for differences in productivity growth between Alberta and Canada.[514]

436. EPCOR submitted that neither the company itself nor its expert Dr. Cicchetti have proposed an adjustment for the productivity differences between the U.S. and Canada or between Canada and Alberta. During the hearing, Dr. Cicchetti explained that the data for Canadian companies do not exist in a fashion that would allow anyone to have an authoritative opinion on the difference in productivity between Canadian and U.S. electric distribution utilities.[515] At the same time, when establishing the components of EPCOR's PBR plan, Dr. Cicchetti urged the Commission to recognize that the actual trend in input prices for labour in Alberta are likely to be above the past trends in the U.S. reflected in NERA's data.[516] As a result, EPCOR submitted that the Commission should not increase the X factor "to something more than -1.0 per cent" that Dr. Cicchetti recommended for the company, given the difference in U.S. and Alberta labour economics.[517]

437. Fortis noted that the company did not ground its X factor approach or recommendation on the basis of a productivity gap. Furthermore, Fortis submitted that the relevant Canada to Alberta considerations in the company's proposal were with respect to the I factor, where the appropriate "Albertasizing" of input price measures was undertaken.[518]

438. The CCA did not believe that any adjustment to the X factor to account for the U.S.-Canada productivity gap was necessary. Having examined the analysis of MFP conducted in several papers by Statistics Canada, PEG found that productivity growth differences between the United States and Canada "vary so widely by industry as to render economy-wide differences in productivity growth useless in quantifying differences in productivity growth between specific industries in the two countries."[519] In addition, PEG observed that the productivity gap between the U.S. and Canada was largely due to differences in sectors that do not include utilities, such as mining and oil extraction and manufacturing.[520]

439. In a similar vein, NERA indicated that it was not aware of any evidence to point to a productivity gap between U.S. and Canadian utilities:

> NERA has seen no evidence to point to a productivity gap between US and Canadian utilities. The existence of a macroeconomic productivity gap between the US and Canada does not necessitate the existence of a productivity gap between US and Canadian utilities – or even suggest such a gap for companies, which operate as regulated utilities in markets subject to highly similar sets of accounting, administrative and legal institutional arrangements in the US and Canada.[521]

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513 Exhibit 628, AltaGas argument, page 30.
514 Exhibit 628, AltaGas argument, page 31.
515 Transcript, Volume 11, page 2009, lines 16-24.
516 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).
517 Exhibit 630.02, EPCOR argument, paragraphs 74-75.
518 Exhibit 633, Fortis argument, paragraphs 130-131.
519 Exhibit 376.01, ATCO-CCA-42(c).
520 Exhibit 376.01, ATCO-CCA-42(c).
521 Exhibit 291.02, Calgary-NERA I-9(c), Exhibit 195.01, AUC-NERA-7.

440. Calgary stated that there is fundamentally little if any difference between the productivity of the U.S. and Canadian distribution utilities.[522] Similarly, the UCA expressed its concerns with establishing the existence of a productivity gap between U.S. and Canadian distribution companies based on the difference in productivity in the overall Canadian economy compared to the overall U.S. economy. In their evidence, Dr. Cronin and Mr. Motluk presented the results of various studies of Canadian electric and gas distribution utilities showing that the TFP growth rates of Canadian distribution companies were "notably higher" than for the U.S. distribution companies as measured by NERA's TFP growth rate.[523] As such, the UCA's experts argued that there was a reverse productivity gap between U.S. and Canadian distribution companies.[524]

Commission findings

441. Parties did not dispute the fact that there presently exists a well-recognized difference between the rate at which the U.S. and the Canadian economies have been able to improve productivity (referred to as a "productivity gap"). Using macroeconomic productivity data from Statistics Canada and the U.S. Bureau of Labour Statistics, NERA showed that, on average, productivity in the U.S. economy grew 0.95 percentage points per year faster that productivity in the Canadian economy over the 1972 to 2009 period.[525]

442. At the same time, parties could not agree on whether the same productivity gap exists between the U.S. and Canadian electric and gas distribution industries. Little direct evidence on whether a gap exists is available. Dr. Carpenter and Dr. Cicchetti pointed to the fact that it is not possible to directly review the productivity gap in the electric and gas utility sectors, as no data on productivity growth for Canadian electric and gas companies exist.[526] The UCA experts proposed examining TFP growth estimates of Canadian utilities obtained from various regulatory proceedings for this purpose. However, in the Commission's view, because the TFP estimates introduced by Dr. Cronin and Mr. Motluk represent a variety of sources, methods, samples and time periods, it is uncertain whether these estimates can be directly compared to NERA's TFP calculation to make a judgment on the existence of a productivity gap for the electric and gas distribution industries between the two countries.[527] As such, the Commission will proceed with evaluating the indirect evidence of a productivity gap between U.S. and Canadian utilities.

443. On a conceptual level, the Commission agrees with NERA's and the interveners' proposition that the existence of a macroeconomic productivity gap between the U.S. and Canada does not mean that there is a productivity gap between U.S. and Canadian utilities. As Dr. Lowry explained:

> And also the thrust of my evidence is that if you look under the hood of the Canadian economy and go sector by sector, it's nothing, you know, remotely true that all the sectors are behind their American counterparts. The numbers are just all over the place. So there's very bad predictive value by saying that for a given industry just because the Canadian economy's productivity trend is slower that therefore a given sector should be slower.[528]

522 Exhibit 629, Calgary argument, page 28.
523 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 76-79 and 86-87.
524 Exhibit 634.02, UCA argument, paragraphs 134-135.
525 Exhibit 80.02, NERA report, page 20, Table 4.
526 Exhibit 476.01, Carpenter rebuttal evidence, page 41; Transcript, Volume 11, page 2009, lines 16-24 (Cicchetti).
527 Exhibit 299.02, Cronin and Motluk UCA evidence, pages 78-79.
528 Transcript, Volume 13, page 2562, lines 11-19.

444. To examine which particular sectors of the Canadian economy contribute to a productivity gap, parties relied on a number of government and academic studies. For example, Dr. Carpenter observed that one Statistics Canada study[529] found evidence of the labour productivity gap in six of the nine industries examined, including utilities and transportation, manufacturing, retail trade, information and cultural industries; and finance, insurance, and real estate. Another study[530] that Dr. Carpenter relied on identified a U.S.-Canada productivity gap in 20 of 33 categories, including electric utilities, gas utilities, mining, food, textiles, printing, and electrical machinery.[531]

445. However, the Statistics Canada study[532] referenced by the CCA's experts, PEG, did not support this conclusion and showed that "the MFP trend of the engineering sector of the economy which includes energy utilities actually exceeded that of the U.S. over a recent sample period."[533] Another study by Statistics Canada[534] quoted by PEG showed that in the 2000 to 2008 period, the decline in the business sector MFP growth rate was due chiefly to declining productivity in two industrial classifications: mining and oil and gas extraction, and manufacturing.[535] The UCA also presented the results of an academic study[536] showing that for the period from 1961 to1995, Canada was "significantly more productive than the United States in coal mining, construction, tobacco, petroleum refining, electric utilities, and gas utilities."[537]

446. Without engaging in a debate on the methodology, time period and relevance of the academic studies discussed in this proceeding,[538] the Commission observes that there is no consensus in the literature on whether a productivity gap exists for the utility sector in general or for the electric and gas distribution sectors in particular. On a related issue, Dr. Carpenter pointed out that there remains a disagreement among the researchers as to the possible explanations for the U.S.-Canada productivity gap.[539]

447. Furthermore, as Dr. Carpenter indicated, some of the academic studies on productivity referenced by the parties in this proceeding refer to the Canadian utility sector in general, which includes power generation and transmission in the electric utilities sector and water and sewage systems in the natural gas utilities sector.[540] As such, it is uncertain whether the productivity of the utilities sector reported in the studies is an accurate reflection of the electric and gas distribution companies' TFP growth.

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529 Baldwin, John and Wulong Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends*, Statistics Canada, August 2009 (No. 25), Statistics Canada.

530 Gu, Wulong and Mun Ho, *A Comparison of Industrial Productivity Growth in Canada and the United States*, Published in Industry-level Productivity and International Competitiveness between Canada and the United States, 2001.

531 Exhibit 98.02, Carpenter evidence, page 28.

532 Baldwin, Gu and Yan, *Relative Multifactor Productivity Levels in Canada and the United States: A Sectoral Analysis*, The Canadian Productivity Review, June 2008 (No. 19), Statistics Canada.

533 Exhibit 636, CCA argument, paragraph 102.

534 Baldwin and Gu, *Productivity Performance in Canada, 1961 to 2008: An Update on Long-term Trends,* The Canadian Productivity Review, August 2009 (No. 25), Statistics Canada.

535 Exhibit 636, CCA argument, paragraph 102.

536 Lee, Frank C., and Jianmin Tang. 2000. *Productivity Levels and International Competitiveness between Canadian and U.S. Industries.* American Economic Review, 90(2): 176-179.

537 Exhibit 634.02, UCA argument, paragraphs 136-138.

538 Exhibit 476.01, Carpenter rebuttal evidence, pages 42-46; Exhibit 650, AltaGas reply argument, paragraph 87.

539 Exhibit 98.02, Carpenter evidence, page 29.

540 Exhibit 98.02, Carpenter evidence, page 26; Exhibit 476.01, Carpenter rebuttal evidence, page 45.

448. In light of the conflicting evidence from the government and academic research, and the uncertainty of whether the results of such research can be used for establishing the existence of a productivity gap between U.S. and Canadian distribution utilities, the Commission considers that no definitive conclusion can be reached on the existence of such a gap. Further, the Commission finds it to be significant that parties observed the business, operational and regulatory similarities between utilities in both jurisdictions. For example, NERA commented on the similarity of the institutional frameworks in which the Canadian and U.S. utilities operate. As NERA explained:

> [F]rom the constitutional foundation through to administrative practices, accounting practices and judicial review, Canada and the United States have virtually indistinguishable regulatory environments – so much so that the US *Hope* and *Bluefield* decisions are even cited in Canadian rate cases.[541]

449. Dr. Cicchetti also pointed to similarities in the business environment between the utilities in the two countries by observing that electric and gas distribution companies in both the United States and Canada "are certainly the last remaining holdout in the U.S. context of unionized employees."[542]

450. In light of these considerations, the Commission finds that no adjustment to NERA's TFP is necessary to account for the observed economy-wide productivity gap between the U.S. and Canada. The Commission observes that Dr. Carpenter was not aware of any jurisdiction in Canada that has adjusted a TFP estimate in setting the X factor in recognition of the productivity gap between the two countries.[543]

451. With respect to a Canada-Alberta productivity gap, the Commission notes that Dr. Carpenter's conclusions as to the existence of such a gap were largely derived from the examination of the CSLS study.[544] However, as the Commission explained earlier in this section and in Section 6.3.7, because the CSLS study used the same methodology and underlying data that Statistics Canada employed in calculating its MFP indexes, it is not clear to what degree the results of this study are reflective of the productivity trends in the electric and gas distribution industries.

452. More importantly, the Commission explained in Section 6.2 of this decision that the X factor should reflect the average rate of productivity growth in the industry. Accordingly, the Commission agrees with Dr. Carpenter's observation about the size of the ATCO companies and concludes that because the companies in this proceeding make up a large part of the utility sector in Alberta, an adjustment for a Canada-Alberta productivity gap (in the utility sector) would result in an X factor that would reflect the companies' own experience rather than industry productivity trends.[545]

453. Dr. Cicchetti proposed that when setting the X factor for Alberta companies, some recognition be given to the fact that the actual trend of input prices for labour in Alberta is likely to be above the past trends in the U.S. that are reflected in NERA's TFP estimates.[546] In

541 Exhibit 391.02, NERA second report, page 20.
542 Transcript, Volume 11, page 2071, lines 3-6.
543 Transcript, Volume 4, page 635, lines 7-11.
544 Exhibit 98.02, Carpenter evidence, page 33.
545 Exhibit 98.02, Carpenter evidence, pages 33-34.
546 Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

EPCOR's view, the consequence of this would be that NERA's TFP growth rate would be higher than the actual TFP growth rate for Alberta.[547]

454. The Commission has a number of concerns with the EPCOR proposition. First of all, Dr. Cicchetti did not provide any information on the relative labour inflation in Alberta and the United States for NERA's study period to support his conclusion that labour inflation in Alberta has been consistently higher than labour inflation in the U.S. over this entire period.

455. Furthermore, the actual impact of labour inflation on the TFP estimate is not so direct as to warrant an immediate upward adjustment to NERA's estimates. NERA explained that its overall input index (in the form of a Tornqvist-Theil volume index) primarily captures changes in input volume.[548] Because NERA used the number of employees as a labour quantity measure,[549] the resulting TFP estimate is largely, but not completely, insulated from the effect of labour inflation. NERA explained that its overall input index "is affected by input prices to the extent that the input expenses are the shares by which the input volumes are weighted."[550] Since NERA used nominal dollars to construct the input price shares,[551] adjusting for higher labour inflation (assuming that the labour inflation in Alberta was consistently higher than in the United States) would result in a higher share of labour in NERA's input index. However, a higher share of labour in the overall input index does not necessarily lead to a reduction to TFP. For example, if the rate of growth in the labour index (i.e., labour quantity) were lower than the rate of growth of the capital and materials indexes (quantities of capital and materials), assigning more weight to the labour index would actually result in a lower overall input index. Holding the output index constant, this would result in a higher TFP growth.

456. In the absence of any analysis on how historical Alberta labour inflation would affect NERA's TFP estimate, the Commission cannot accept EPCOR's proposition that an adjustment to the TFP factor is necessary to account for the difference in U.S. and Alberta labour economics.

6.4.3 Effect on the X factor of excluding capital from the application of the I-X mechanism

457. Because EPCOR's proposed PBR plan indexes only operating costs and excludes capital costs, Dr. Cicchetti noted that a PFP (partial productivity factor) measuring only changes in O&M productivity was a relevant measure to use instead of TFP as a basis for EPCOR's X factor.[552] The ATCO companies agreed with this logic and submitted that if all capital expenditures were to be excluded from indexing under the PBR plan, a different X factor would likely be required based on the PFP associated with O&M.[553]

[547] Exhibit 630.02, EPCOR argument, paragraphs 74-75.
[548] Exhibit 195.01, AUC-NERA-3(a) and (d).
[549] As NERA explained in its second report, before 2002, NERA used number of employees for labour quantity. Because FERC Form 1 no longer contains employee data after 2002, NERA estimated the number of employees using the inflation-adjusted distribution payroll growth for the years 2002 to 2009. (Exhibit 391.02, NERA second report, page 10). In either period, labour quantity is measured by a number of employees, and is not reflective of labour inflation.
[550] Exhibit 195.01, AUC-NERA-3(d).
[551] Exhibit 195.01, AUC-NERA-3(b).
[552] Exhibit 103.05, Cicchetti evidence, page 20.
[553] Exhibit 631, ATCO Electric argument, paragraph 102 and Exhibit 632, ATCO Gas argument, paragraph 112.

458. The UCA argued that the same reasoning applies to the exclusion from indexing of a portion of capital expenditures. Because NERA's TFP estimate was based on the entirety of the distribution companies' inputs (i.e., capital, labour and materials), the UCA argued that the exclusion of some or all capital from the I-X mechanism would require an adjustment to NERA's TFP and the resulting X factor.[554] At the same time, the UCA observed that the issue of what the relevant X factor should be in this case was not addressed in this proceeding, and a separate process was required:

> However, if the Commission determines that there is need for a capital adjustment outside of the I-X mechanism, then a separate proceeding is definitely required. The proceeding would have to examine the appropriate X factor having regard to the exclusion of a material portion of capital from the I-X mechanism. This alternative creates additional regulatory burden. It would create uncertainty for the Applicants and the ratepayers. The UCA does not recommend this alternative.[555]

459. PEG observed that to the extent that the capital expenditures excluded from indexing are sizable and involve the "normal kinds of [capital expenditures] undertaken by the sampled utilities," it may be necessary to raise the TFP estimate.[556] To support its view, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP growth to increase from 1.32 per cent to 1.53 per cent.[557]

460. In response, the ATCO companies submitted that based on the structure of their PBR plans, there is no need to adjust the TFP (and the resulting X factor). Specifically, the ATCO companies noted that while some capital expenditures were included as flow-through factors under the companies' respective plans, the vast majority (approximately 85 per cent for ATCO Electric and 95 per cent for ATCO Gas) of their revenues were covered under the I-X portion of the plan. As such, the ATCO companies argued that their PBR plans were comprehensive, and thus no adjustment to the X factor was required.[558]

461. Similarly, AltaGas indicated that under the revenue-per-customer cap proposed by the company, the impact of capital expenditures removed from the I-X mechanism and included in the proposed flow-through factor represented only around five per cent of the company's total revenue requirement. AltaGas argued that given the relative size, scope and the effective isolation of the projects included in the flow-through factor from other elements of the company's plan, there was no reason to adjust the X factor for the exclusion of some part of capital.[559]

Commission findings

462. The Commission agrees in principle with the CCA's and the UCA's view that because NERA's study measures changes in output compared to changes in all of the companies' inputs (that is, labour, materials and capital), NERA's TFP estimate may not be precisely applicable to PBR plans that exclude all or a part of capital from the application of the I-X mechanism. However, for the reasons explained below, the Commission has not made any adjustment to

[554] Exhibit 634.02, UCA argument, paragraph 204.
[555] Exhibit 634.02, UCA argument, paragraph 205.
[556] Exhibit 307.01, PEG evidence, page 60.
[557] Exhibit 307.01, PEG evidence, page 29.
[558] Exhibit 631, ATCO Electric argument, paragraph 103 and Exhibit 632, ATCO Gas argument, paragraph 113.
[559] Exhibit 628, AltaGas argument, pages 31-32.

NERA's TFP estimate to account for capital that is excluded from the application of the I-X mechanism.

463. With respect to excluding all capital from the application of the I-X mechanism, the Commission explained in Section 2.3 that it did not accept EPCOR's proposal to exclude capital and apply the I-X mechanism only to the O&M and other non-capital costs. As such, no consideration of the partial productivity factors of the type proposed by Dr. Cicchetti is required in determining the X factor for EPCOR's proposed PBR plan.

464. With respect to the exclusion of some capital, as further discussed in Section 7.3.2.4 of this decision, the Commission's preferred method of dealing with companies' concerns regarding unusual capital expenditures is through the use of capital trackers. The Commission acknowledges that, in theory, because the capital expenses subject to these trackers will be not be subject to the I-X mechanism, NERA's TFP number may need to be adjusted.

465. However, the Commission observes that the direction of any TFP adjustment to account for the exclusion of some of the capital is not clear, as demonstrated by the parties' conflicting evidence on this subject. Dr. Cicchetti's analysis showed that excluding capital from NERA's TFP estimate results in a more negative PFP trend, and therefore the X factor when capital is excluded from the application of the I-X mechanism should be lower than if capital were included.[560] In contrast, PEG showed that for its sample of companies, excluding 10 per cent of capital expenditures causes TFP to rise. Accordingly, to the extent that the capital expenditures excluded from indexing are sizable, the CCA experts advocated a higher X factor.[561]

466. Additionally, the Commission indicated in Section 7.3.4 below that it is not approving any of the capital factors proposed by the companies as part of this decision. In Section 7.3.4, the Commission has invited the companies to file their capital proposals in their first capital tracker filing on or before November 2, 2012. In its submissions, the UCA was referring to the exclusion of a "material portion of capital" from the application of the I-X mechanism.[562] AltaGas and the ATCO companies argued that their proposed capital flow-through factors (which, in AltaGas' view were of a nature similar to NERA's definition of a capital tracker) would not have a large effect on the overall revenue requirement.[563]

467. In light of this conflicting evidence and the resulting uncertainty as to the materiality and the direction of any adjustment to account for the exclusion of some capital from the I-X mechanism, the Commission will not be making any adjustments to TFP during the PBR term to account for the fact that some capital may be excluded from the application of the I-X mechanism.

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560 Exhibit 103.05, Cicchetti evidence, pages 22-24.
561 Exhibit 307.01, PEG evidence, pages 29 and 60.
562 Exhibit 634.02, UCA argument, paragraph 205.
563 Exhibit 628, AltaGas argument, page 32; Exhibit 631, ATCO Electric argument, paragraph 103; Exhibit 632, ATCO Gas argument, paragraph 113.

6.5 Stretch factor

6.5.1 Purpose of the stretch factor

468. Generally speaking, a stretch factor is an additional percentage applied to the X factor, thereby increasing the overall value for X and thus slowing the price or revenue cap growth determined by the I-X indexing mechanism.[564]

469. Parties to this proceeding differed in their interpretation as to the purpose of the stretch factor and based their recommendations accordingly. Nevertheless, most parties to this proceeding agreed that the rationale behind the stretch factor is to share with customers the benefits of the expected acceleration in productivity growth as the company transitions from a cost of service ratemaking system to performance-based regulation. Dr. Cicchetti explained the logic behind this reasoning as follows:

> In North America, an industry productivity trend that is estimated using historical data will overwhelmingly reflect the productivity experience of an industry that has been regulated using cost of service methods. [...] A principal rationale for PBR is to create stronger performance incentives compared with cost of service regulation. This, in turn, implies that when utilities become subject to PBR, it is expected that they will achieve incremental productivity gains compared to what has been observed under traditional cost of service regulation. The productivity “stretch factor” reflects the expectation that productivity growth will increase, at least temporarily, under incentive regulation and adding this “stretch” goal to an estimate of the historical productivity trend embodies an estimate of these expected, incremental productivity gains in the approved X-factor.[565]

470. Another EPCOR expert, Dr. Weisman, further elaborated on this reasoning and emphasized that the stretch factor is designed to ensure that consumers share in part of the efficiencies created by moving from the cost of service to the PBR regime:

> DR. WEISMAN: The typical rationale, and one that I would agree with, is that when you move to a more high powered regulatory regime, such as price cap regulation, that this will fundamentally change the incentives of the firm, that it will be able to enhance its efficiencies, and the stretch factor is designed to ensure that consumers share in part of those efficiencies. So it basically bounces up our historical view of productivity growth to account for the change of the enhanced incentives that accompany price cap regulation relative to traditional cost-of-service regulation.
> Q. So it's good for that period of time when you move from cost of service into incentive-based regulation? Is that fair?
> A. DR. WEISMAN: Generally the focus is on the transition. You probably heard the so-called low-hanging fruit argument, that the -- in the initial transition the efficiency gains what we can change, how we can innovate are more obvious and apparent than they are later on.[566]

471. AltaGas,[567] NERA,[568] the UCA[569] and Calgary,[570] supported this rationale behind the stretch factor. Accordingly, these parties supported the inclusion of a stretch factor in the

564 Exhibit 98.02, Carpenter evidence, page 34; Exhibit 307.01, PEG evidence, page 16.
565 Exhibit 103.05, Cicchetti evidence, pages 27-28.
566 Transcript, Volume 9, page 1766, lines 4-22.
567 Exhibit 110.01, AltaGas application, paragraph 45 and Transcript, Volume 9, page 1689, lines 19-24.
568 Exhibit 195.01, AUC-NERA-12(a) and Transcript, Volume 1, page 116, lines 21-24.
569 Transcript, Volume 17, page 3287, lines 14-25.

companies' PBR plans. The parties' specific recommendations as to the size of the stretch factor are discussed in the following section of this decision.

472. In Ms. Frayer's view, which Fortis adopted, a stretch factor is a mechanism to adjust the company's revenue or rates each year to reflect firm-specific expected productivity gains vis-à-vis the gains expected for the industry as a whole. In other words, according to Ms. Frayer, a stretch factor "creates an incremental incentive for productivity, in order to "catch-up" with the rest of industry, in the case of a company that is underperforming."[571] In that regard, Fortis argued that because of its strong productivity performance in recent years (as demonstrated by the continued reduction in controllable operating costs per customer since 2004), there was no "low-hanging fruit" for the company to pick under PBR.[572]

473. The CCA and its expert, Dr. Lowry, indicated that both the operating efficiency of the company and the difference between the incentive power of the current regulation and the PBR plan should form part of the consideration as to whether to add a stretch factor.[573] Similarly, Dr. Carpenter expressed his view that both of these considerations are relevant in determining whether a stretch factor is required:

> If there is evidence to suggest that a particular utility is less efficient than the industry as a whole, and if the incentives for improving efficiency are likely to be much stronger in the future than they have been in the past, then it might be reasonable to expect that utility to be able to achieve more rapid productivity growth than the historical trend rate measured in a TFP study. A stretch factor may then be appropriate.[574]

474. However, the Dr. Lowry and Dr. Carpenter did not agree on whether a stretch factor should be assigned to Alberta companies. In Dr. Carpenter's view, it is not clear whether the PBR regime will create much stronger incentives for efficiency than the existing cost of service regime since the current regulation in Alberta contains "significant efficiency incentives because of the time between rate cases and the forward-looking test periods."[575] As such, the ATCO companies argued that a stretch factor should not be applied to their PBR plans.[576]

475. In contrast, Dr. Lowry and his colleagues at PEG argued that the current regulatory system in Alberta, under which the companies file rate cases every two years, has "weak performance incentives."[577] Accordingly, Dr. Lowry noted it is reasonable to expect that there will be some productivity acceleration in Alberta with the adoption of a PBR regime and, as a result, a stretch factor should be included in the companies' PBR plans.[578]

476. Finally, in discussing whether a stretch factor should be a part of the companies' PBR plans, parties to this proceeding pointed to an inter-relationship between a stretch factor and an ESM (earnings sharing mechanism). Specifically, all the companies contended that a stretch factor and an ESM were mutually exclusive and preferred to keep only the one alternative of

570 Exhibit 298.02, Calgary evidence, paragraph 133 and Transcript, Volume 15, page 2935, lines 18-25.
571 Exhibit 100.02, Frayer evidence, page 79.
572 Exhibit 633, Fortis argument, paragraphs 144-146.
573 Exhibit 636, CCA argument, paragraph 108 and Transcript, Volume 13, pages 2564-2565.
574 Exhibit 476.01, Carpenter rebuttal evidence, page 62.
575 Exhibit 476.01, Carpenter rebuttal evidence, page 58.
576 Exhibit 631, ATCO Electric argument, paragraph 108; Exhibit 632, ATCO Gas argument, paragraph 118.
577 Transcript, Volume 13, page 2564, lines 6-10 and Exhibit 307.01, PEG evidence, page 46.
578 Transcript, Volume 13, page 2564, lines 3-10 and Exhibit 636, CCA argument, paragraph 118.

their choice.[579] Accordingly, EPCOR and AltaGas argued that an ESM should not be a part of their plans, given that their PBR proposals contained a stretch factor.[580] Conversely, in the view of the ATCO companies and Fortis, the inclusion of an ESM in their PBR plans provided an additional justification for not imposing a stretch factor.[581]

477. On this issue, NERA commented that, although there may be some aspects of a trade off between an ESM and a stretch factor, it does not view an ESM and a stretch factor as mutually exclusive.[582] The CCA and the UCA experts shared this view as demonstrated by the fact that PEG's incentive power model and the X factor menu advocated by Dr. Cronin and Mr. Motluk included both an ESM and a stretch factor.[583]

478. Calgary also offered that there is no mutual exclusivity between an ESM and a stretch factor. In Calgary's view, a stretch factor is intended to deal with the attempt to capture the additional efficiencies resulting from the transition from the cost of service regime to PBR. In contrast, the ESM is intended to address the proper sharing of any efficiencies derived from operating under the I-X mechanism that are achieved during the PBR term.[584] Calgary noted that a number of PBR plans in North America have both of these elements, as shown in NERA's second report.[585]

Commission findings

479. The Commission agrees with the rationale for a stretch factor put forward by EPCOR, NERA, AltaGas, the UCA and Calgary. The purpose of a stretch factor is to share between the companies and customers the immediate expected increase in productivity growth as companies transition from cost of service regulation to a PBR regime.

480. The ATCO companies and the CCA agreed that this reasoning forms part of the consideration when adding a stretch factor. As such, the Commission observes that this definition of stretch factor has been accepted by all parties to this proceeding, except Fortis.

481. In Fortis' view, a stretch factor should be added if a particular company were found to be less efficient than the industry as a whole. The ATCO companies and the CCA also noted that this rationale should be considered when determining the need for a stretch factor. However, as set out in Section 6.2 of this decision, the Commission does not wish to engage in this type of analysis for the purposes of PBR in Alberta because of the practical and theoretical problems associated with comparing efficiency levels among companies. Therefore, the Commission did not include the consideration of the companies' comparative levels of efficiency in its determination on the need for a stretch factor.

482. The Commission agrees with Dr. Weisman that the transition from cost of service regulation to PBR provides an opportunity to realize more easily-achieved efficiency gains (the

579 Exhibit 98.02, ATCO Electric application, paragraph 45; Exhibit 99.01, ATCO Electric application, paragraph 41; Exhibit 529, AltaGas corrections and amendments to application, page 4; Exhibit 100.02, Fortis application, paragraphs 83-84; Exhibit 103.02, EPCOR application, paragraphs 84-85.
580 Exhibit 103.02, EPCOR application, paragraphs 84-85; Exhibit 529, AltaGas corrections and amendments to application, page 4.
581 Exhibit 98.02, Carpenter evidence, page 35; Exhibit 100.02, Fortis application, paragraph 85.
582 Exhibit 195.01, AUC-NERA-12(d).
583 Transcript, Volume 13, page 2579, lines 17-21; Transcript, Volume 17, page 3188, lines 13-19.
584 Exhibit 629, Calgary argument, page 60.
585 Exhibit 391.02, NERA second report, Table 3, page 30.

"low hanging fruit") due to increased incentives.[586] In the Commission's view, two issues are salient when considering the need for a stretch factor. The first issue is whether NERA's TFP estimate, on which the X factors for the Alberta companies are based, provides a good estimate for the productivity growth under PBR. As Dr. Cicchetti explained, in the case that an industry TFP trend is estimated using historical data that predominantly reflect the productivity experience under cost of service regulation, such a TFP target may need to be "stretched" to account for higher incentives under PBR.[587] However, it is not clear the extent to which NERA's data include both cost of service and PBR forms of regulation,[588] and there was no evidence on the record of this proceeding upon which to make such an adjustment.

483. The second issue to consider is whether there is a potential for the Alberta companies to collect the "low-hanging fruit" when transitioning from the current cost of service regulation to a PBR framework. In that regard, the Commission does not share Dr. Carpenter's view that the efficiency incentives under the current cost of service price setting framework in Alberta and PBR are going to be largely the same.

484. On the same topic, Fortis and the ATCO companies also argued that there will be no "low-hanging fruit" to pick under PBR because of the companies' strong productivity performance in recent years.[589] However, as the CCA pointed out, it is possible that the companies are unable to appraise the productivity gains that are achievable under PBR.[590] Dr. Weisman addressed this matter in an academic article that he co-authored as follows:

> With very limited potential rewards but significant disallowance risks, the traditional regulatory model strongly encourages the prudent use of tried-and-true operating practices and technologies. It thus provides very limited incentives, if not explicit disincentives, to look beyond the status quo to discover and employ new, innovative operating practices and technologies. This is why the provision of enhanced incentives can stimulate a discovery process that enables regulated firms to become more efficient than they previously knew how to be.[591]

485. The Commission observes that having analysed its recent experience under PBR, ENMAX also pointed to a number of efficiency improvements and cost-minimising measures that were realized since the transition to a regulatory regime with stronger efficiency incentives. Notably, ENMAX indicated that the company would not have undertaken these productivity initiatives under a traditional cost of service regulatory framework.[592]

486. Finally, the Commission notes that the companies characterized the inclusion of a stretch factor (or a lack thereof) as an alternative to an ESM. In this regard, the Commission agrees with NERA and the interveners that although there is some trade-off between an ESM and a stretch

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586 Transcript, Volume 9, page 1766, lines 4-22.
587 Exhibit 103.05, Cicchetti evidence, pages 27-28.
588 Exhibit 299.02, Cronin and Motluk UCA evidence, page 79, footnote "c".
589 Exhibit 633, Fortis argument, paragraphs 144-146; Exhibit 631, ATCO Electric argument, paragraph 271; Exhibit 632, ATCO Gas argument, paragraph 296.
590 Exhibit 645, CCA reply argument, paragraph 47.
591 Exhibit 500.02, Weisman, Dennis L., and Pfeifenberger, Johannes P., *Efficiency as a Discovery Process: Why Enhanced Incentives Outperform Regulatory Mandates*, The Electricity Journal, January-February 2003, page 60.
592 Exhibit 297.01, ENMAX evidence, pages 16-18.

factor, they are not mutually exclusive.[593] This is demonstrated by the fact that a number of PBR plans in North America have both of these components.[594] Nevertheless, as set out in Section 10 of this decision, the Commission determined that an ESM should not be part of the companies' PBR plans. Accordingly, the inclusion of an ESM in the PBR plans of the companies cannot provide an additional justification for not imposing a stretch factor.

487. In light of the above considerations, the Commission agrees with EPCOR, AltaGas and the interveners that a stretch factor should be a part of the PBR plans for the Alberta companies.

6.5.2 Size of the stretch factor

488. Parties acknowledged that unlike TFP estimates, stretch factors are commonly set based upon regulatory judgment and evidence from other jurisdictions rather than on a theoretical basis.[595] However, in the parties' view, this judgement has to be informed by the empirical evidence to accord with best regulatory practices.[596]

489. In this respect, Dr. Cicchetti found informative the average level of the stretch factor assigned to electric distributors in Ontario. The Ontario Energy Board, in its third generation incentive regulation plan, set the stretch factors at 0.2 per cent, 0.4 per cent and 0.6 per cent for the most efficient, the average efficient and the least efficient distributors, respectively. The average of the stretch factors imposed by the Ontario Energy Board is 0.4 per cent. Dr. Cicchetti noted that this was also the stretch factor approved by the Commission for ENMAX in Decision 2009-035.[597] Given Dr. Cicchetti's view that his recommended O&M PFP was of a "conservative nature," and in conjunction with not having an ESM, EPCOR's expert recommended that the company's PBR plan include a stretch factor of 0.2 per cent that lies at the mid-point between a stretch factor of zero (Dr. Cicchetti's preferred value), and the 0.4 per cent assigned to ENMAX.[598]

490. The UCA also relied on the Ontario Energy Board's determination on the stretch factor. The UCA indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[599]

491. AltaGas indicated that it is prepared to dispense with the ESM with the addition of a "modest stretch factor of between 0.1-0.2 per cent."[600] Dr. Schoech explained that this recommendation reflected his evaluation of how the X factor should change if an ESM is removed from the plan.[601]

593 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 13, page 2579, lines 17-21 (Dr. Lowry); Transcript, Volume 17, page 3188, lines 13-19 (Dr. Cronin); Exhibit 629, Calgary argument, page 60.
594 Exhibit 391.02, NERA second report, Table 3, page 30.
595 Exhibit 195.01, AUC-NERA-12(d); Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
596 Exhibit 103.05, Cicchetti evidence, page 28; Exhibit 634.02, UCA argument, paragraph 152; Transcript, Volume 13, page 2567, lines 1-10 (Dr. Lowry).
597 Decision 2009-035, paragraph 185.
598 Exhibit 103.05, Cicchetti evidence, pages 30-31.
599 Exhibit 634.02, UCA argument, paragraph 146.
600 Exhibit 529, AltaGas corrections and amendments to application, page 4.
601 Transcript, Volume 9, page 1689, lines 9-16.

492. PEG indicated that its research suggests that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent. In developing its stretch factor recommendations, PEG examined regulatory precedent and noted that the average explicit stretch factor approved for PBR plans of energy companies with rate escalation mechanisms informed by productivity research is about 0.50 per cent.[602] In addition, PEG developed an incentive power model that estimates the typical cost performance improvements that will be achieved by companies under stylized regulatory systems. Calibrating this model for the circumstances of Alberta companies produced a stretch factor value of 0.19 per cent.[603] Based on the results of PEG's research, the CCA recommended that all companies be assigned the 0.19 per cent stretch factor that resulted from PEG's incentive power model.[604]

493. Based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[605]

494. Similar to the discussion about the size of the X factor, parties commented on whether the presence and the magnitude of a stretch factor have any effect on the incentives of PBR plans. EPCOR, AltaGas and the ATCO companies submitted that the strength of the incentives under a PBR plan is not tied to the magnitude of the X factor (including the stretch).[606] NERA and the CCA supported this view.[607]

495. In contrast, Calgary argued that inasmuch as the companies are going to be incented to find capital and operating efficiencies under PBR relative to the cost of service regulation, a stretch factor "will play a key role as an additional driver to achieve those efficiencies."[608] In a similar vein, the UCA submitted that a stretch factor should incent a company to "obtain maximum efficiency improvements."[609]

496. Fortis' evidence on this matter was contradictory. On one hand, Fortis argued that "the level of X, regardless of whether that level includes some notion of stretch, does not determine if the incentive properties of PBR grow or diminish. Whatever X is, or more accurately the result of I-X is, the incentive to attain and better that result exists."[610] On the other hand, Fortis submitted that "the imposition of a stretch factor [...] by its nature and effect could only increase the perceived incentive to cut costs in any available manner."[611]

602 Exhibit 307.01, PEG evidence, page 45.
603 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
604 Exhibit 636, CCA argument, paragraph 106.
605 Exhibit 629, Calgary argument, page 33.
606 Exhibit 630.02, EPCOR argument, paragraph 86; Exhibit 628, AltaGas argument, page 34; Exhibit 631, ATCO Electric argument, paragraph 112; Exhibit 632, ATCO Gas argument, paragraph 122.
607 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.
608 Exhibit 641, Calgary reply argument, paragraph 132.
609 Exhibit 634.02, UCA argument, paragraph 157.
610 Exhibit 644, Fortis reply argument, paragraph 86.
611 Exhibit 633, Fortis argument, paragraph 157.

Commission findings

497. As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a "definitive analytical source" like the TFP study represents.[612]

498. The UCA's experts recommended that the Commission assign stretch factors of between 0.2 and 0.6 per cent, similar to the Ontario Energy Board's determination in its third generation incentive regulation plans.[613] Dr. Cicchetti also found informative the average level of the stretch factor assigned to electric distributors in Ontario, and recommended a stretch factor of 0.2 per cent.[614] PEG proposed that stretch factors for Alberta companies should lie in the range of 0.19 to 0.5 per cent.[615] A similar range of 0.13 to 0.5 per cent was advocated by Calgary.[616] AltaGas recommended a stretch factor of 0.1 to 0.2 per cent.[617]

499. Taking into account the fact that the companies are moving from a cost of service regulatory framework to PBR, and being cognizant of the uncertainties associated with the change in regulatory framework, the Commission is taking a conservative approach to setting a stretch factor. Accordingly, the Commission considers that a stretch factor for Alberta companies should be on the lower end of the 0.2 to 0.6 per cent ranges recommended by PEG and the UCA's experts. The Commission observes that the CCA expressed its preference for a stretch amount on the lower side of the 0.19-0.5 per cent range recommended by its experts, PEG.[618] The Commission has considered the recommended stretch factors and finds a 0.2 per cent stretch amount to be reasonable. This stretch factor should apply to the companies' plans for the duration of the PBR term.

500. Finally, the Commission agrees with the parties who argued that while the size of a stretch factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs.[619] Similar to a discussion in Section 6.1 of this decision, the Commission considers that PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes).[620]

6.6 X factor proposals and the Commission determinations on the X factor

501. As discussed previously in this section, the X factor proposals in this proceeding reflected the parties' views as to the purpose of and approaches to determining the X factor, the relevant productivity estimates to use and the need for any adjustments, as well as considerations on the need for a stretch factor. Table 6-2 below shows that the parties' recommendations for an X factor are based on a variety of time periods and TFP indexes that the parties considered relevant.

612 Transcript, Volume 1, page 115, lines 6-19 (NERA). On this subject, see also Exhibit 103.05, Cicchetti evidence, page 28; Transcript, Volume 9, page 1688, lines 18-23 (Dr. Schoech); Transcript, Volume 4, pages 776-778 (Dr. Carpenter).
613 Exhibit 634.02, UCA argument, paragraph 146.
614 Exhibit 103.05, Cicchetti evidence, pages 30-32.
615 Exhibit 307.01, PEG evidence, page 45 and Exhibit 478, PEG rebuttal evidence, page 24.
616 Exhibit 629, Calgary argument, page 33.
617 Exhibit 628, AltaGas argument, page 33.
618 Exhibit 636, CCA argument, paragraph 106.
619 Exhibit 628, AltaGas argument, page 34;
620 Transcript, Volume 1, page 117, lines 10-15 (NERA); Exhibit 636, CCA argument, paragraph 112.

Table 6-2 Summary of the X factor proposals

	ATCO Electric/ ATCO Gas[621]	EPCOR[622]	Fortis[623]	AltaGas[624]	CCA[625]
Starting point	-0.28 to -1.09	-1.0	-1.0	-1.0 to -1.7	1.32 for gas companies 1.08 to 1.23 for electric companies
Productivity research relied upon	NERA's TFP	PFP based on NERA's data	Statistics Canada MFP index and NERA TFP	Statistics Canada MFP index and NERA TFP	PEG's TFP for gas companies NERA's TFP for electric companies
Time period	1994-2009 and 1999-2009	1999-2009	2000-2009	2000-2009	1996-2009 (PEG data) 1989-2007 (NERA data)
Adjustment for the U.S.-Canada productivity gap	-1.31 to -1.73	--	--	--	--
Stretch factor[626]	No	0.2	No	0.1 to 0.2	0.19
Proposed X factor (in per cent)	**-2.0**	**-1.0**	**-1.0**	**-1.3**	**1.08 to 1.32**

Note: Numbers do not add up due to a number of assumptions and qualifications that parties incorporated in their X factor proposals (for example, choice of a mid-point value for a range of X, application of a stretch factor only if an ESM was excluded from the plan, etc.).

502. Calgary recommended an X factor in the range of 1.0 to 1.7 per cent based on the results of NERA's and PEG's productivity studies.[627] As well, based on the record of this proceeding, Calgary recommended that the stretch factor be in the range of 0.13 per cent to 0.5 per cent.[628]

503. IPCAA did not make a specific recommendation on the X factor except to mention that a negative X factor unduly increases the risk of the companies over-earning.[629]

504. The UCA's experts, Dr. Cronin and Mr. Motluk, recommended using the X factor and ROE menu discussed in the Ontario Energy Board's *2000 Draft Rate Handbook*.[630] As set out in Section 6.2, the Commission did not accept the UCA's menu approach. The UCA also indicated that if the menu approach to the X factor is not adopted, it recommends stretch factors for the

621 Exhibit 98.02, Carpenter evidence, page 32, Table 3.
622 Exhibit 103.05 Cicchetti evidence, page 16.
623 Exhibit 100.02, Frayer evidence, pages 78-79.
624 Exhibit 110.01, Christensen Associates evidence, pages 13-15.
625 Exhibit 636, CCA argument, paragraphs 60-62.
626 Exhibit 631, ATCO Electric argument, paragraph 106; Exhibit 632, ATCO Gas argument, paragraph 116; Exhibit 630.02, EPCOR argument, paragraph 81; Exhibit 633, Fortis argument, paragraph 142; Exhibit 628, AltaGas argument, page 33; Exhibit 636, CCA argument, paragraph 106.
627 Exhibit 629, Calgary argument, page 24.
628 Exhibit 629, Calgary argument, page 33.
629 Exhibit 635, IPCAA argument, pages 2-3 and Exhibit 642, IPCAA reply argument, paragraphs 5-6.
630 http://www.oeb.gov.on.ca/documents/cases/RP-1999-0034/handbook0.html.

companies of between 0.2 and 0.6 per cent based on the current Ontario third generation PBR plan approach.[631]

Commission findings

505. As noted earlier in this section, the parties' X factor proposals were based on a variety of productivity indexes, approaches, and sample periods that they considered to be the most relevant in determining the X factor.

506. There was some discussion about whether the X factor to be used in a PBR plan necessarily has to be positive. The companies contended that there is nothing inherently wrong with a negative X factor. All companies proposed negative X factors in their respective PBR applications. Calgary did not agree with this conclusion and argued that a negative X factor does not provide the proper incentives to reduce costs.[632] IPCAA observed that a lower X factor would lead to a higher risk of company over-earning.[633]

507. On this issue, the Commission agrees with the companies' argument that, in theory, the X factor does not necessarily have to be always positive. As NERA's and EPCOR's experts explained during the hearing, a negative TFP (and the resulting X factor) just means that a particular industry grows more slowly in its productivity than the economy as a whole or that input costs are growing faster in the industry than in the economy.[634] Because the economy-wide productivity represents the average productivity of different industries comprising the national economy, some of the industries must be below average and some above. For instance, Dr. Makholm and Dr. Schoech pointed to the construction industry as an example of a sector with slower productivity growth.[635]

508. In Section 6.2 of this decision, the Commission reiterated its preference for an approach to setting the X factor based on the long-term rate of productivity growth in the industry. The Commission dismissed the alternative approaches to determining the X factor, such as the building blocks approach proposed by Fortis and the efficiency benchmarking and menu approaches proposed by the UCA.

509. In Section 6.3 of this decision, the Commission examined multiple aspects of the parties' TFP recommendations and determined that the results of NERA's TFP study represent a reasonable starting point for establishing a productivity estimate for Alberta electric and gas distribution companies. Based on the results of NERA's study, the Commission determined that a long-term industry TFP of 0.96 per cent represents a reasonable basis for determining the X factors to be used in the PBR plans of the electric and gas distribution companies. In this proceeding, parties discussed several potential adjustments to TFP to arrive at the X factor, some of which would have resulted in a negative X factor.

510. Specifically, NERA explained that the theory behind PBR plans may require an input price differential and a productivity differential adjustment to TFP if an output-based measure is used for the I factor.[636] However, the Commission explained in Section 6.4.1 above that because

631 Exhibit 634.02, UCA argument, paragraph 146.
632 Exhibit 629, Calgary argument, page 30.
633 Exhibit 304.01, IPCAA evidence, page 2.
634 Transcript, Volume 3, page 487, lines 20-22 and Volume 11, page 1987, line 17 to page 1988, line 11.
635 Transcript, Volume 3, page 488, lines 24-25, Volume 9, page 1678, lines 17-25.
636 Exhibit 461.02, AUC-NERA-17(a) and (b).

both components of the approved I factors can be considered input-based price indexes, no adjustment to TFP is required.

511. Additionally, Dr. Carpenter on behalf of the ATCO companies indicated that NERA's TFP analysis based on U.S. data needed to be adjusted for a productivity gap between the U.S. and Canadian economies.[637] Dr. Schoech on behalf of AltaGas also noted that this productivity gap warrants consideration.[638] As well, Dr. Carpenter and Dr. Cicchetti urged the Commission to consider the possible adjustment for the productivity performance of the Alberta economy when setting the X factor for the companies.[639] The Commission has reviewed the issue of productivity gap in Section 6.4.2 of this decision and determined that no adjustment to NERA's TFP is necessary to account for the differences in the economy-wide productivity growth between the U.S. and Canada, or Canada and Alberta.

512. The Commission has considered IPCAA's suggestion that a stretch factor be used to adjust for 2012 rates for historical over-earning. Give the approach the Commission has taken to the requested adjustments to going-in rates requested by the companies (see Section 3.4), the Commission will not make an adjustment to the stretch factor for that purpose. In Section 3.4, the Commission rejected adjustments to going-in rates to reflect selected actual results on 2012 because those adjustments could not be made without concurrently reviewing all actual results for 2012. The Commission will not assume what the results of such a review might be and seek to capture assumed 2012 productivity gains through an increased stretch factor.

513. Parties also discussed the effect on X of excluding all or part of capital from the I-X mechanism, as set out in Section 6.4.3. In that regard, because the Commission did not accept EPCOR's proposal to exclude capital from its PBR plan, no consideration of the partial productivity factors, of the type proposed by Dr. Cicchetti, is required in determining the X factor for the companies. With respect to the exclusion of only some capital, the Commission determined that no adjustments to TFP will be made during the PBR term to account for the possible exclusion of some capital from the I-X mechanism.

514. Based on the above, the Commission finds that no adjustments to the industry TFP growth rate are required when establishing the X factors for the companies. Accordingly, the Commission finds that the X factor to be used in the PBR plans of the electric and gas distribution companies prior to consideration of a stretch factor is 0.96 per cent.

515. Furthermore, as set out in Section 6.5 of this decision, the Commission determined that a stretch factor of 0.2 per cent will apply to the companies' PBR plans for the duration of the PBR term. Accordingly, the Commission finds that the total X factor for the electric and gas distribution companies, inclusive of a stretch factor, will be 1.16 per cent.

637 Transcript, Volume 4, pages 595-596.
638 Transcript, Volume 8, page 1414, lines 9-25.
639 Exhibit 98.02, Carpenter evidence, pages 33-34; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-9(b).

7 Adjustment to rates outside of the I-X mechanism

7.1 Introduction

516. The Commission recognizes the need to make provision for recovery of a limited number of costs outside of the I-X mechanism. It is common for PBR plans to make special provision to reflect the cost impact of significant unforeseen events that are outside the ability of the regulated entity to control. Approved costs of this nature are recovered through a Z factor rate adjustment. In addition, the companies have proposed a capital factor for the recovery of certain specific capital project costs as well as Y factor rate adjustments to permit the flow through to customers of third party charges that are beyond the control of the companies, Commission directed costs, deferral accounts and certain other costs. This section will review each of the proposals to deal with costs outside of the I-X mechanism.

7.2 Z factors

517. A Z factor is ordinarily included in a PBR plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

518. The Commission considered the criteria for when the impact of an exogenous event would qualify for a Z factor adjustment to rates in Decision 2009-035 and accepted the following proposal put forward by Dr. Cronin:[640]

> With respect to exogenous events, the Commission considered the evaluation criteria proposed by Dr. Cronin, and has determined that the following criteria for an exogenous adjustment should be adopted.
>
> 1) The impact must be attributable to some event outside management's control;
> 2) The impact of the event must be material. It must have a significant influence on the operation of the utility otherwise the impact should be expensed or recognized as income, in the normal course of business;
> 3) The impact of the event should not have a significant influence on the inflation factor in the FBR formulas; and
> 4) All costs claimed as an exogenous adjustment must be prudently incurred.

519. Applying these criteria, if an exogenous event has an economy-wide impact, the cost of that impact will be reflected in and recovered through the I factor. Providing the company with additional revenues through a Z factor adjustment in circumstances where the event has economy-wide impacts would result in a double-counting of the impact of the exogenous event. The criteria adopted by the Commission in Decision 2009-035 also speak to the recovery of costs after they have been incurred and subsequently found by the Commission to have been prudently incurred.

520. All of the companies' proposed plans include Z factors and generally agreed with the continued use of the criteria established in Decision 2009-035.[641]

[640] Decision 2009-035, Section 9.3, paragraph 247, page 54.

521. NERA stated that generally PBR plans have Z factors to permit "[u]tilities to recover the costs of unforeseeable events with material impacts."[642] However, NERA also suggested that Z factors should be limited to exogenous factors that impact the entire industry "like a tax change, or a change in investment tax credit, or something else that would lift or lower the price that the industry would have to compete against if we were talking about a competitive business."[643] A Z factor should not be used to address the impact of an exogenous event which affected the company alone.[644]

522. All interveners accepted that Z factors are a necessary component of a PBR plan.[645] The primary concern of interveners was to limit the use of Z factors by having clearly defined criteria and appropriate materiality thresholds. The UCA suggested the continued use of the criteria from Decision 2009-035 because those criteria were working well in the ENMAX plan, and there is no evidence to the contrary.[646] Calgary proposed an alternative set of criteria that were substantially similar to the four criteria adopted in Decision 2009-035, and added a criterion requiring the company to promptly report the event when first discovered.[647]

Commission findings

523. The Commission considers it necessary to include a Z factor in the PBR plan to account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan. The Commission continues to support the criteria established in Decision 2009-035 to determine if the impacts of an exogenous event qualify for Z factor treatment, with one clarification. The Commission considers that for the negative impact of an exogenous event to qualify for cost recovery, the extent of the impact must, by necessary implication, be unforeseen prior to the occurrence of the event. This criterion is necessary to distinguish the cost impacts of exogenous events that are not foreseeable from the cost impacts of other events that are beyond the company's control but are foreseeable and therefore may qualify for Y factor treatment as discussed in Section 7.4 below. In Decision 2009-035 the Commission also made a distinction between exogenous adjustments and flow-through items by stating:[648]

> With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them.

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641 Exhibit 628.01, AltaGas argument, Section 9.1, page 47; Exhibit 630.02, EPCOR argument, Section 9.1, paragraph 159, page 59; Exhibit 631.02, ATCO Electric argument, Section 9.2, paragraph 205, page 54; Exhibit 632.01, ATCO Gas argument, Section 9.2, paragraph 214, page 70; Exhibit 100.02, Fortis application, Section 7, paragraph 118, page 34.

642 Exhibit 391.02, NERA second report, Section IV-C-3, paragraph 71, page 35.

643 Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.

644 Transcript, Dr. Makholm, Volume 1, pages 179-180.

645 Exhibit 634.02, UCA argument, Section 9.1, paragraph 209, page 38; Exhibit 636.02, CCA argument, Section 9.1, paragraph 145, page 59; Exhibit 942.01, IPCAA reply argument, Section 9.0, paragraph 12, page 2; Exhibit 629.01, Calgary argument, Section 9.1, page 42.

646 Exhibit 634.02, UCA argument, Section 9.2, paragraph 214, page 38.

647 Exhibit 629.01, Calgary argument, Section 9.2, page 43.

648 Decision 2009-035, Section 9.3, paragraph 251, page 55.

524. Accordingly, the Commission considers that the following criteria will apply when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

(1) The impact must be attributable to some event outside management's control.
(2) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.
(3) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.
(4) All costs claimed as an exogenous adjustment must be prudently incurred.
(5) The impact of the event was unforeseen.

525. The Commission considers that all of the above criteria must be met in order for an item to qualify for a Z factor rate adjustment.

526. Inclusion of a Z factor based on clearly defined criteria is consistent with the Commission's PBR principles. The Commission observes that when an exogenous event occurs within a competitive industry that is not generally felt within the economy as a whole, the companies within the industry will generally adjust their prices in response to the event. A Z factor will permit the regulated distribution companies in Alberta to do the same. The Commission notes that Dr. Makholm agreed with this characterization.[649]

527. With respect to the opinion of Dr. Makholm that a Z factor should not be available to deal with the impacts of a company specific exogenous factor because it would not parallel competitive markets, the Commission notes that no such restriction was imposed in Decision 2009-035. Further, the Commission considers that allowing a company specific exogenous factor to potentially qualify for Z factor treatment is in keeping with the fourth Commission PBR principle which states that the design of PBR plans should recognize the unique circumstances of each regulated company. Also, allowing recovery of the costs of a company specific exogenous event is consistent with providing the company with a reasonable opportunity to recover its prudently incurred costs. Accordingly, the impact of company specific exogenous events will not be excluded from consideration for Z factor treatment.

528. The Commission considers that Z factors should be symmetrical in that they should apply to exogenous events with both additional costs that the company needs to recover and also reductions to costs that need to be refunded to customers. The Commission agrees with the CCA and considers it necessary to allow the Commission and interveners to apply for Z factor adjustments to rates where circumstances warrant.

7.2.1 Z factor materiality

529. Materiality may be considered on an event-by-event basis or cumulatively. Under the ENMAX FBR plan, materiality is evaluated on an event-by-event basis.[650] Most of the companies in this proceeding proposed that materiality be evaluated on a cumulative basis. That is, if the sum of the effects of a number of exogenous events in a year would have a material impact on the company, they should be considered as though they were one event for Z factor purposes.

[649] Transcript, Dr. Makholm, Volume 1, page 179, lines 5-9.
[650] Decision 2009-035, Section 9.3, paragraph 231, page 51.

530. The following table sets out the materiality thresholds of the Z factor as approved for ENMAX in Decision 2009-035 and as proposed by each of the companies in this proceeding:

Table 7-1 Summary of companies Z factor materiality proposals

	ENMAX[651]	AltaGas[652]	ATCO Electric[653]	ATCO Gas[654]	EPCOR[655]	Fortis[656]
Threshold	$1.0 million	Variable (approx. $0.2 million)[657]	$0.5 million	$0.5 million	$1.0 million distribution $0.5 million transmission	$0.5 million
Basis for determining the threshold	Size of revenue requirements	Annual impact on ROE ≥ +/- 25 basis points	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria	Rule 005 variance threshold criteria[658]
Cumulative	No	Yes	Yes	Yes	Yes	No

531. Concerns were raised by interveners over having materiality thresholds set too low, particularly when materiality is measured on a cumulative basis, because it allows companies to qualify for Z factor adjustments on too frequent a basis. It was suggested by Calgary's witness, Mr. Matwichuk that AUC Rule 005[659] is not the appropriate source for finding the criteria to determine the materiality thresholds for Z factor adjustments, and if comparisons to PBR plans in other jurisdictions are made, a higher threshold would be used.[660] The UCA suggested that the materiality thresholds should be established by taking 0.25 per cent of net assets, which would result in significantly higher threshold levels.[661]

532. The CCA stated that it is appropriate to address the materiality of Z factors on an individual event basis in order to achieve consistency with the process established in Decision 2009-035.[662] Dr. Lowry submitted that having low materiality thresholds that could result in frequent Z factor applications is contrary to the spirit of PBR. Dr. Lowry stated the following at the oral hearing:

> I can tell you too that, you know, in some jurisdictions, including the Ontario Energy Board, they're not very encouraging to the utilities to come in even for Z factor proposals as violating the spirit of the PBR.[663]

Commission findings

533. Setting a Z factor threshold too low invites parties to submit applications on too frequent a basis, and undermines the regulatory efficiency that PBR seeks to achieve. Setting a Z factor

651 Decision 2009-035, Section 9.3, paragraph 248, page 54.
652 Exhibit 110.01, AltaGas application, Section 7.2, paragraph 84, page 26.
653 Exhibit 98.02, ATCO Electric application, Section 7, paragraph 206, page 7-1.
654 Exhibit 99.01, ATCO Gas application, Section 2.6, paragraph 112, page 40.
655 Exhibit 103.02, EPCOR application, Section 2.3.4.1, paragraphs 134-140.
656 Exhibit 219.02, AUC-ALLUTILITIES-FAI-19.
657 Transcript, Mr. Mantei, Volume 8, page 1487.
658 Transcript, Mr. Lorimer, Volume 12, page 2238.
659 Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
660 Transcript, Mr. Matwichuk, Volume 15, page 2953.
661 Exhibit 634.02, UCA argument, Section 9.2, paragraph 217, page 39.
662 Exhibit 636.01, CCA argument, Section 9.3.1, paragraph 152, page 61.
663 Transcript, Dr. Lowry, Volume 14, page 2673.

threshold too high may limit a company's reasonable opportunity to recover prudently incurred costs, or conversely may prevent customers from realizing the benefit of a reduction in costs.

534. Exogenous events may occur during the PBR term but by definition they are exceptional occurrences which may either add costs to, or remove costs from, the provision of utility service. Additionally, not all events beyond the control of the company will qualify under other Z factor criteria, thereby further reducing the number of already rare events that could result in a rate adjustment outside of the I-X mechanism. Given the exceptional nature of a qualifying exogenous event and the equally exceptional measure of authorizing a recovery outside of the I-X mechanism, the Commission considers that the PBR principles require a relatively high threshold and that this threshold should apply to each event unless otherwise permitted in exceptional circumstances.

535. The Commission considers that the approach to establishing a materiality threshold based on the impact to ROE as proposed by AltaGas is reasonable. However, the Commission finds that the materiality threshold should be higher. In order to establish the threshold the Commission has calculated the impact on ROE that the dollar threshold established for ENMAX represented in 2006 (going-in rates). Accordingly, the Commission establishes the threshold as the dollar value of a 40 basis point change in ROE on an after tax basis calculated on the company's equity used to determine the revenue requirement on which going-in rates were established (2012). This dollar amount threshold is to be escalated by I-X annually. The companies are directed to calculate and file the 2012 threshold amount along with supporting calculations in the compliance filing to this proceeding.

7.2.2 Process for considering a Z factor application

536. Having separate Z factor applications from the PBR annual filings may result in a need for more applications, and therefore may increase the administrative burden. However, if separate Z factor applications can be completed prior to the PBR annual filings, the annual filing process will not be complicated with potentially contentious Z factor items.

537. The companies generally agreed that addressing Z factors as part of the annual PBR rate adjustment filing process, rather than through a separate regulatory process, would be in the best interests of regulatory efficiency.[664] Fortis raised concerns that a Z factor application may require a protracted review, and as such, including Z factors as part of the annual PBR rate adjustment filing process may not be optimal.[665]

538. The UCA stated that "[t]o maximize regulatory efficiency, Z factor applications should be made at the same time as deferral and other PBR filings."[666] Calgary addressed the issue of how to process Z factor applications when it included a new criterion for Z factors that "the utility will be required to report promptly at the first discovery of an event and then apply for disposition of the accumulated savings or costs at the time of annual reporting."[667] In addition,

[664] Exhibit 632.01, ATCO Gas argument, Section 9.3, paragraph 219, page 71; Exhibit 631.01, ATCO Electric argument, Section 9.3, paragraph 210, page 55; Exhibit 630.02, EPCOR argument, Section 9.3, paragraph 168, page 63; Exhibit 628.01, AltaGas argument, Section 9.3, page 48.

[665] Exhibit 633.01, Fortis argument, Section 9.3, paragraph 180, page 83.

[666] Exhibit 634.02, UCA argument, Section 9.3, paragraph 220, page 40.

[667] Exhibit 629.01, Calgary argument, Section 9.2, page 43.

the CCA stated that "the utilities and stakeholders should both be eligible to file Z factor proposals."[668]

539. The Commission outlined the process for Z factor applications in Decision 2009-035.

> In order to ensure fairness to all stakeholders, EPC or other parties are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. The Commission also directs that the impact of any proposed exogenous adjustment be initially captured in a separate account pending a ruling from the Commission. The impact of any proposed adjustment is to be measured from the time the event occurred. The disposition of the account would follow the Commission's ruling on the proposed adjustment.[669]

Commission findings

540. The Commission finds that the process established in Decision 2009-035 is satisfactory. Accordingly, companies are directed to notify the Commission of all proposed exogenous adjustments as soon as possible after the event that gives rise to them is identified. Further, Z factor applications should be submitted as soon as possible after the costs associated with the exogenous event have been incurred or the savings have been realized.

541. A party may file a Z factor application at any time. However, in order to minimize the number of rate adjustments during the year, unless otherwise permitted, the Commission directs that Z factor rate adjustment applications be filed as part of the annual PBR rate adjustment filing. Please see Section 15.1.2 for a more detailed explanation of how the inclusion of Z factor amounts will be included in the annual PBR rate adjustment filing process.

542. In Decision 2009-035 the Commission recognized that some Z factors may result from changes in circumstances that carry forward into future periods.

> The Commission recognizes that, in some cases, a "Z" adjustment for an extraordinary event will be transitory and will not be subject to the I minus X adjustment. In other cases, the extraordinary event may require a "Z" adjustment that is subject to the I minus X adjustment going forward. The Commission will make this determination on a case by case basis.[670]

543. The Commission recognizes that some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis.

7.3 Capital factors

7.3.1 Need for a capital factor

544. All of the companies argued that they are experiencing some cost pressures on capital expenditures that will require special treatment under PBR. There was some agreement among NERA and the experts representing the companies and interveners that certain types of unusual

668 Exhibit 636.01, CCA argument, Section 9.1, paragraph 145, page 59.
669 Decision 2009-035, Section 9.3, paragraph 250, page 55.
670 Decision 2009-035, Section 9.3, paragraph 249, page 54.

capital expenditures may require capital factors as part of a PBR plan to provide for sources of revenue in addition to the revenue generated by the I-X mechanism.

545. The companies offered several reasons why capital factors are required, including the costs being outside of the control of the company, the costs to build capital being significantly higher than historic norms, the need to build specific large projects, and high growth rates of the system. Another reason that was cited by several of the companies was a surge in replacement activities requiring an unusually high level of capital expenditures during the PBR term.[671] Because of the long term nature of utility assets, the cycles in which the companies purchase capital assets are much longer than the length of the PBR term. The evidence and testimony indicated that installation of large amounts of facilities during high growth periods in the past creates an echo effect when those facilities come to the end of their useful lives and must be replaced in current dollars with large replacement projects. Consequently, the companies submitted that if a utility is at a stage where it must invest more than the historical rate of capital asset growth or capital asset replacement assumed in the X factor, a special capital factor may be required.[672]

546. Experts representing the interveners acknowledged that under some circumstances special treatment of capital may be required, although most of the interveners took issue with the extent to which special capital treatment had been proposed.[673] There was concern expressed that double-counting may occur in circumstances where the companies should be able to recover the capital expenditures through the I-X mechanism, but are also provided with relief through a capital factor.[674] The double-counting may occur because the I-X mechanism already provides funding for capital projects and the addition of a capital factor outside of the formula would provide that funding again. The CCA also argued that companies have some flexibility in the timing of replacement expenditures without affecting safety or reliability, so utilities may have the ability to defer some replacement capital expenditures instead of seeking a capital factor adjustment.[675]

547. One of the concerns with approving capital factors is that the efficiency incentives created by a PBR plan may be reduced because the incentives to find efficiencies by substitution among various types of inputs (expenses and capital) may be lessened. In an exchange with Commission counsel, Dr. Makholm addressed how significant of a concern this is.

> Q. If the Commission was to accept company proposals that excluded significant capital components, does that mean that the X factor, if it was the same as your TFP estimate, would be wrong?
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> A. DR. MAKHOLM: It wouldn't mean that the TFP growth number that we've calculated, that's then used for the X factor, would be wrong. It would call into question

671 Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 97, page 36; Exhibit 631.01, ATCO Electric argument, Section 8.3, paragraph 146, page 40; Exhibit 628.01, AltaGas argument, Section 5.4, page 32.

672 Exhibit 98.02, ATCO Electric application, Section 5, paragraph 46, page 5-1; Exhibit 99.01, ATCO Gas application, Section 2.4, paragraph 45, page 20; Exhibit 628.01, AltaGas argument, Section 8.2, pages 38 to 39; Exhibit 630.02, EPCOR argument, Section 8.2, paragraph 96, page 35

673 Exhibit 629.01, Calgary argument, Section 8.3, page 40, Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 49, Exhibit 634.02, UCA argument, Section 8.3, paragraph 182, page 33.

674 Transcript, Dr. Makholm, Volume 1, page 162.

675 Exhibit 636.01, CCA argument, Section 8.1, paragraph 118, page 46.

> the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.
>
> The theory upon which this kind of PBR formula is based doesn't apply to a kind of regime that would only target, for instance, O&M costs. So in that respect, the formula is wrong. The application of PBR in this context, drawing upon a competitive paradigm, is wrong; not the calculation of the TFP growth itself.[676]

548. The UCA agreed with NERA's opinion with respect to the impact on PBR incentives that results from the use of capital factors.

> The creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market. For the examples listed, the factors affecting the forecast are not beyond the utility's control, in fact the decision to proceed is entirely a utility management decision. Management must weigh the costs and benefits of all options, including the status quo, and decide on a course of action.[213] If there is flow-through treatment, the incentive to examine alternatives will be eliminated.[677]
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> [213] Exhibit 0300.02, Evidence of Russ Bell at A26.

Commission findings

549. The Commission recognizes that the TFP study used to determine the X factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan. The capital proposals of the companies were all quite different. Some companies asked for considerably more capital to be treated outside of the I-X mechanism than others.

550. The Commission shares the concerns raised by NERA and interveners that a capital factor must be carefully designed in order to maintain the efficiency incentives of PBR, and also to avoid double-counting. At issue are the types and levels of capital expenditures that can reasonably be expected to be recovered through the I-X mechanism. The Commission finds that a mechanism that permits the recovery of specific types of capital outside of the I-X mechanism should be included in a PBR plan. In the sections of this decision that follow, the Commission addresses these issues by adopting a capital factor that, to the greatest extent possible, seeks to maintain the incentive properties of PBR and avoids double-counting.

7.3.2 Methodologies for addressing capital

551. A number of alternatives for a capital factor were explored during the proceeding. These included determining the average rate of capital growth in the TFP study and providing for

[676] Transcript, Volume 1, page 143.
[677] Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, pages 35-36.

capital in addition to that amount as required, modifying the X factor in consideration of a need for higher capital spending, excluding all capital from going-in rates and the I-X mechanism, and providing compensation for capital needs outside of the normal course of the company's operations by way of a capital tracker.

7.3.2.1 The average rate of capital growth in the TFP study

552. Dr. Carpenter approached the issue of identifying the amount of capital expenditures that the I-X mechanism can support by proposing that the capital factor be calibrated by comparing the capital requirements of the company to a benchmark level established by the median level of growth in plant observed in the utilities in the NERA TFP study.[678] Dr. Carpenter examined capital investment information about the companies in NERA's TFP study to estimate that the median level of annual growth in plant was 4.5 per cent over the relevant time period of the NERA TFP study that he used to determine the X factor he proposed.[679]

553. There were several issues identified with respect to the approach suggested by Dr. Carpenter.

554. Dr. Makholm commented on Dr. Carpenter's analysis as follows:

> Simple trends from past data series not having to do with our type of TFP growth study is what he is proposing as a way of creating -- I can't remember whether it was his Y or K factor, I'm not sure, one of those two. I think in our evidence and in responses to data request responses -- data requests, we drew a line between those types of things and the specific ring fenced engineering-based justified capital expenditures that consumed our 15 or 20 minutes before the break. For our purposes, at least for my purposes, using that kind of trend to project capital input over the course of a PBR plan is not very reliable. I wouldn't do it.[680]

555. NERA also stated:

> Under this logic additional adjustments would need to be made to account for the fact that the regulated firm's labor input and material input may be growing at different trend rates than the 72 utilities in the NERA sample. If, however, adjustments are made to each input to account for the differences between the trend rates of the regulated firm and the 72 utilities the result would be that regulated prices would be tied to actual productivity changes of the regulated firm rather than the industry's productivity. This means that the PBR incentive properties would be similar to the incentive properties under cost of service regulation. An important linchpin of performance based regulation and price cap regulation is that the X factor represents the productivity of the industry and not the productivity of the regulated company.[681]

556. NERA also calculated a different capital growth rate of 1.32 per cent for 1972 to 2009 based on the capital index used in its TFP study.[682] NERA stated "[w]e deal with capital quantity inputs measured in a very idiosyncratic way with one hoss shay techniques, and I think what you'll find in response to AUC NERA 15 that we're trying to dissuade anybody from taking the

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[678] Transcript, Dr. Carpenter, Volume 4, page 643.
[679] Transcript, Dr. Carpenter, Volume 4, page 643.
[680] Transcript, Dr. Makholm, Volume 1, page 155.
[681] Exhibit 195.01, AUC-NERA-8(a).
[682] Exhibit 195.01, AUC-NERA-8(b).

trends in capital quantity input we use to arrive at TFP growth analysis from being used to project new investments in whatever over the course of PBR planning."[683] Dr. Ros went on to explain:

> Can I just add productivity growth is the change in outputs and change in the three different inputs. So what Dr. Carpenter has observed is investment, net investment, which is not an input in the TFP study. And your question doesn't follow in the sense you're not mentioning anything about what's going on with output or other input at the same time. But in addition to that, it seems to be implying that in order for a TFP [PBR] plan to be effective you have to track exactly the type of changes that the utilities are likely to experience over the next five years, which does away with the incentive properties of performance-based ratemaking.[684]

557. Dr. Lowry also explained the impact that customer growth has on capital, and that customer growth for the Alberta utilities is more rapid than it is for the typical utility.[685] In theory, a company could be experiencing significantly higher capital growth than 4.5 per cent, but if the capital expenditures are required to add new customers and additional load to the system, there would be offsetting impacts to outputs in the calculation of TFP, and productivity growth would not necessarily be significantly impacted.[686]

558. ATCO Electric employed Dr. Carpenter's analysis to develop the ATCO K factor proposal. That proposal was based on a three plank approach. The first plank was intended to include the level of capital expenditures the I-X mechanism can support, which ATCO Electric determined to be 4.9 per cent annual growth.[687] The second plank was comprised of the remaining amount of capital growth in its current four year capital forecast, which was to be funded by the ATCO K factor. ATCO K factor programs were selected on the basis that they were stable and predictable and could be forecast for a four year period. The third plank was comprised of capital projects that do not occur on a routine basis and, therefore, could not be accurately forecasted. The end result of the three plank approach was that ATCO Electric prepared an overall capital forecast, and proposed a method by which that forecast could be recovered in the PBR plan. Mr. Freedman explained the ATCO Electric approach as follows:

> When we did our forecast of the rate base growth on its own, that showed us that we were closer to 10 percent. So when we were designing the planks, we were just looking at that. We tested the results and the outcomes of all of that afterwards, after we designed the planks to see it was in. What the results were going to give us with these planks was still in the area of reasonableness, and we showed those results in section 16 of the application.[688]

559. Mr. Freedman further explained in a discussion with Commission counsel how the determination of the 4.9 per cent that could be funded from application of the I-X mechanism was determined:

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683 Transcript, Dr. Makholm, Volume 1, page 154.
684 Transcript, Dr. Ros, Volume 1, page 157.
685 Transcript, Dr. Lowry, Volume 13, page 2605.
686 Exhibit 307.01, CCA evidence of PEG, Section 4.1, page 61.
687 Dr. Carpenter had calculated a 4.5 per cent median annual investment growth rate for the companies in the NERA TFP study. ATCO Electric chose 4.9 per cent for its first plank because of the types of capital projects it could identify.
688 Transcript, Mr. Freedman, Volume 7, page 1263.

> So when we looked at the capital maintenance programs and the programs that fell within that definition, we looked at the dollar impact of that. We looked at the results that were arising from that through -- and we would see that through -- in Section 16 of our application. And given that the 4.5 percent was part of a range and that was considered. We could have gone more aggressive but we didn't want to -- we didn't want to gray it up with putting some programs in that may be not quite as stable and predictable and readily factorable. So it could have been more aggressive to get it down to the 4 1/2 percent, but looking at the results that were being generated with the overall plan, ATCO Electric believed that it could put forward the programs as we've selected.
> Q. The 4.9 fell out of that analysis; is that right?
> A. MR. FREEDMAN: Correct.[689]

560. Under its approach ATCO Electric forecasted a total amount of revenue requirement first, and then developed rates (in this case using a PBR formula) to ensure that it is collecting the amount of revenue requirement needed to fund the forecasted amounts over the PBR term.

561. With particular reference to the ATCO Electric K factor, the UCA pointed out that the requirement for business cases for capital spending would have been subject to extensive review under cost of service regulation, and that the same level of testing would be required under PBR if the ATCO Electric K factor approach were used.[690]

Commission findings

562. The Commission finds that the evidence of capital investment growth of the companies included in NERA's total factor productivity study can not be used to determine the average amount of capital expenditures that could be recovered through the I-X mechanism because the Commission agrees with Dr. Makholm's, Dr. Ros' and Dr. Lowry's criticisms that such an approach does not account for the variability of capital investments and other inputs in relation to outputs from year to year. In addition, the Commission agrees with Dr. Makholm's observation that a simple trend analysis of average capital investment is an unreliable predictor of the amount of capital that can be funded through the I-X mechanism. Accordingly, the Commission rejects Dr. Carpenter's approach to determining the amount of capital growth that should be recovered through the I-X mechanism.

563. Because the ATCO Electric approach forecasts the total amount of capital revenue requirement over the PBR term to ensure that it is collecting the amount of revenue needed to fund its forecast capital expenditures, the Commission considers that the adoption of the ATCO Electric proposal would amount to retaining cost of service regulation for all capital but with a four year forecast. The Commission would not only be required to test the projects that comprise the ATCO Electric K factor, but it would also need to test the projects covered by the 4.9 per cent. If the projects that make up the 4.9 per cent were not tested, ATCO Electric could select which projects and types of capital expenditures should be included in the 4.9 per cent thereby avoiding scrutiny of possible double-counting of costs already in the K factor. If the Commission were to direct ATCO Electric to provide details for all capital projects including those captured by the 4.9 per cent, it would represent a return to cost of service regulation for all capital for a four year forecast term, reducing the efficiency incentives that PBR creates and failing to reduce the regulatory burden.

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689 Transcript, Mr. Freedman, Volume 4, pages 685-686.
690 Exhibit 634.02, UCA argument, Section 8.2, paragraph 180, page 32.

7.3.2.2 Modifying the X factor to accommodate the need for higher capital spending

564. There was some discussion that that the X factor could be modified to provide sufficient revenues to cover a higher level of capital investment growth than provided for in the I-X mechanism.

565. In the view of Dr. Carpenter, when developing the X factor from a TFP study it is necessary to take into account the forecasted investment needs of the specific company for which the PBR plan is being designed.[691] As such, Dr. Carpenter appeared to suggest that a smaller X factor was required for the companies that expect a higher than usual level of capital expenditures during the PBR term. At the same time, Dr. Carpenter explained that he did not recommend this adjustment, since the ATCO companies proposed to deal with higher than usual capital expenditures by means of their K factor:

> DR. CARPENTER: ...And I think we also would have to take into account whether or not unusually high [capital expenditures] growth requirements over the plan term would require an X adjustment. Now, in ATCO's case X is not being adjusted for [capital expenditures]. Instead in ATCO Electric's case a K factor has been employed to deal with that issue.
> Q. And in the absence of the K factor you would be recommending an adjustment to the X in addition to the productivity gap?
> A. DR. CARPENTER: One may have to, yes.[692]

566. Fortis and AltaGas stated that if the Commission were to decide not to include capital flow-through factors in the PBR formula, it would be necessary to adjust the X factor to allow the financing of these capital projects under the I-X mechanism.[693] The CCA stated that it would be open to experimentation with such an approach because it has been used in PBR plan designs in other jurisdictions.[694]

567. At the same time, AltaGas acknowledged that this approach would be a "British-style building blocks" approach to developing the X factor, and would unnecessarily complicate the derivation of the formula.[695] Similar to the ATCO Companies, EPCOR, Fortis and AltaGas preferred to deal with unusual capital expenditures by way of flow-through factors, and not by adjusting the X factor.[696]

568. NERA explained that under this approach, the X factor is calculated as the value that would set the customer rates at a level to recover the company's cost of service revenue requirement over a forecast period.[697] In Dr. Makholm's view, forecasts that extend as far into the future as the length of a PBR term become vague, and undermine the effectiveness of a PBR plan.[698] Dr. Makholm concluded:

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[691] Exhibit 476.01, Carpenter rebuttal evidence, page 10.
[692] Transcript, Volume 3, page 592, lines 4-13.
[693] Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 138.
[694] Exhibit 636.01, CCA argument, Section 8.4, paragraph 136, page 55
[695] Exhibit 628, AltaGas argument, page 32 and Exhibit 247.01, AUC-ALLUTILITIES-AUI-7(a).
[696] Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(b); Exhibit 628, AltaGas argument, page 32 and Exhibit 633, Fortis argument, paragraph 139.
[697] Exhibit 391.02, NERA second report, pages 27-28.
[698] Transcript, Volume 1, page 160 and Volume 3, page 502, lines 9-17.

> I think as I've -- as we have tried to distinguish between adjustments to X -- that is, Y factors or K factors -- cognizant of what goes on in Britain, where X is a true-up measure for long-term forecasts, it's our conclusion that it is better to leave X to do what X is designed in North America to do, which is to reflect total factor productivity growth and let other elements of ratemaking reflect unusual or special-case or needed capital expenditures.[699]

Commission findings

569. The companies acknowledged that any attempt to adjust the X factor for the investment needs of a specific company requires a detailed forecast of a company's capital expenditures and the associated revenue requirement, billing determinants, and even inflation over the PBR term.[700] As NERA and AltaGas pointed out, this approach essentially amounts to adopting the building blocks method employed by the regulators in the U.K.[701]

570. In Section 6.2 above, the Commission rejected the use of a building blocks approach and restated its preference for an approach to setting the X factor based on the long term average rate of productivity growth in the industry. Accordingly, the Commission finds that the X factor should not include any adjustments to deal with company-specific forecast capital expenditures.

7.3.2.3 Exclude all capital from going-in rates and the I-X mechanism

571. Due to the complexities of establishing what capital spending should be included and excluded from the I-X mechanism, EPCOR recommended that, in its case, all capital should be excluded from going-in rates and consequently not be subject to the I-X mechanism. Such an approach essentially splits the revenue requirement of the company so that capital is dealt with in a traditional cost of service manner, and the remainder of the revenue requirement is subject to the I-X mechanism and other PBR formula variables. The K factor proposed by EPCOR encompasses all capital.

572. EPCOR was unique amongst the companies in its proposal to exclude all capital from the I-X mechanism. The other companies proposed a limited number of capital factors that were more targeted at specific types of projects. EPCOR argued that it is faced with unique circumstances in that it must replace a more significant portion of its system during the PBR term.[702] While EPCOR considered the options of including all capital within the I-X mechanism and using capital trackers for special circumstances, EPCOR concluded that the regulatory burden would be significantly reduced if it excluded all of its capital from the I-X mechanism because there are too many projects that have complex interrelationships requiring capital tracker treatment.[703]

573. NERA expressed the view that the negative impact on incentives that excluding a significant portion of capital has is significant enough to bring into question whether PBR should

[699] Transcript, Volume 1, page 119, lines 9-17.
[700] Exhibit 233.01, AUC-ALLUTILITIES-EDTI-7(a), Exhibit 201.01, AUC-ALLUTILITIES-AE-7(a), Exhibit 633, Fortis argument, paragraph 78.
[701] Exhibit 247.01 AUC-ALLUTILITIES-AUI-7(a).
[702] Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraphs 105-107, pages 39-41.
[703] Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.

be allowed to proceed. Several interveners supported the opinion of NERA.[704] Dr. Makholm addressed the issue saying:

> It would call into question the basis for the PBR regime itself because, as you just recounted as our answer, the use of a total factor productivity study embraces the idea that different factors of production are substitutable and the substitution of different factors of production over time constitute one of the areas of TFP growth.[705]

Commission findings

574. The Commission has previously considered the EPCOR approach for the complete exclusion of capital from its PBR plan, and rejected this approach for the reasons set out in Section 2.3. The Commission is concerned that excluding all capital or a large portion of the company's capital expenditures from going-in rates and the I-X mechanism would significantly dampen the efficiency incentives of a PBR plan.

7.3.2.4 Capital trackers

575. In its second report and in response to the capital factor proposals made by the companies, NERA referred the Commission to the growing use by some U.S. regulators of capital trackers that allow a regulated firm to track and begin to recover the costs associated with certain capital projects more quickly and more efficiently than in a normal rate case.[706] NERA indicated that capital trackers are "used in various situations where the typical regulatory rate case provides an inadequate mechanism to adjust rates in response to increased investment in infrastructure."[707] NERA indicated that capital trackers could be used in conjunction with a PBR plan to deal with certain special capital requirements. NERA described the purpose and use of capital trackers as follows:

> Capital trackers are used to recover the costs of a classified, pre-approved set of infrastructure investments. The tracker does not include all infrastructure investments, rather only infrastructure investments that meet the classifications set at the on-set of the tracker; all other infrastructure investments are recovered in the company's next rate case proceeding. A "qualified investment" is an investment that meets the pre-set conditions for inclusion in the asset tracker. Typically, the proposed accounts included in a capital tracker go beyond the scope of routine investments required to support existing infrastructure. Qualified investments are specific, non-routine investments recovered outside of the normal rate case proceeding.[708]

576. NERA favoured an approach that did not rely on calculating the dollar amount of capital that could or could not be accommodated by the I-X mechanism. Rather, it focused on the nature of the projects and whether those projects are consistent with the past practices of the company. NERA said that unusual projects may need special capital treatment, but "because everybody's rates are based on their own books and records in base rates, and if the company has been doing

704 Exhibit 629.01, Calgary argument, Section 8.6, page 41; Exhibit 636.01, CCA argument, Section 8.6, paragraph 138, page 56; Exhibit 634.02, UCA argument, Section 8.2, paragraph 175, page 31.
705 Transcript, Dr. Makholm, Volume 1, page 143.
706 Exhibit 391.02, NERA second report, Section 4, paragraphs 86-91, pages 41-43.
707 Exhibit 391.02, NERA second report, Section 4, paragraph 88, page 42.
708 Exhibit 391.02, NERA second report, Section 4, paragraph 90, page 43.

whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense."[709]

577. NERA described the capital tracker mechanism by stating that "the basic idea of a capital tracker is to recover the costs of qualified infrastructure investments incurred between rate cases through an asset tracker."[710] This means that once a capital project has been identified as a capital tracker the costs associated with the project are tracked and a cost of service revenue requirement calculation is performed for the project to determine the amount of revenue the company requires. That revenue requirement is collected by the company through rate adjustments outside of the I-X mechanism.

578. When asked why a capital tracker is any better than any other exclusion of capital from the I-X mechanism, and in particular a PBR plan which excludes capital entirely, Dr. Makholm stated:

> That's a fair question. Capital trackers are there because there's not an administrative and practical way in the commission's judgment to deal with certain kinds of aged infrastructure any other way than to have a rate base case. That issue of capital affects PBR jurisdictions as much as it affects any other jurisdiction.
>
> The difference between that kind of targeted engineering-based approach to particular kinds of aged infrastructure or lumpy prospective capital and the proposals from one of the utilities to do an O&M only rate cap plan I think are large and manifest.
>
> One takes a piece of prospective capital expense and subjects it to the microscope of justification and engineering so that the public is well served through the efficient replacement of infrastructure that the public needs. That is specific and targeted.
>
> The other type, which is apply PBR only to O&M, is neither specific nor targeted, it's general. And for practical purposes, I think observers can distinguish between those two kinds of methods of regulation.[711]

579. NERA stated that one of the main benefits of the capital tracker approach is that, by limiting the trackers to a few very specific items it maintains the incentive properties of PBR for most of the plan, while still recognizing that some relief may be required for companies to handle lumpy investments.[712]

580. The capital tracker approach was supported by several other parties.[713] In addition, most of the parties agreed that a capital tracker approach is reasonable for inclusion in a PBR plan. Even EPCOR, which discarded capital trackers as a viable option for its own plan, acknowledged that the incentive properties of capital trackers are superior to the exclusion of all capital from the I-X mechanism it proposed.[714]

709 Transcript, Volume 1, page 162.
710 Exhibit 391.02, NERA second report, Section 4, paragraph 89, page 42.
711 Transcript, Dr. Makholm, Volume 1, pages 146-147.
712 Transcript, Dr. Makholm, Volume 1, pages 146-147.
713 Transcript, Dr. Weisman, Volume 10, pages 1906-1907; Transcript, Mr. Camfield, Volume 8, page 1457; Transcript, Ms. Frayer, Volume 12, page 2395; Transcript, Dr. Lowry, Volume 13, page 2627; Transcript, Mr. Bell, Volume 18, pages 3274-3275.
714 Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 106, page 33.

581. While agreeing with the underlying premise for a capital tracker, ATCO Electric expressed its concern about the inability to determine the amount of capital that can be funded outside of the I-X mechanism.[715] EPCOR raised a related concern when it argued that its analysis had shown that a capital tracker approach "proved unworkable due to the complex interrelationships between baseline capital and new capital and the lack of any credible basis upon which to separate the two in a well-defined, defensible manner."[716] EPCOR concluded that the issues around splitting capital costs were substantial enough to warrant excluding all capital from the I-X mechanism.

582. ATCO Electric stated that the capital tracker approach is an alternative it could work with.

> However, if ATCO Electric's approach is not acceptable to the Commission then a well defined tracker mechanism that encompasses ATCO Electric's programs currently included in ATCO Electric's K factor would be an alternative that ATCO Electric could work with.[717]

583. Some companies proposed to deal with some capital expenditures through capital Y factors on the basis that the level of expenditures was so significant that the I-X mechanism could not handle them. The ATCO Electric and ATCO Gas material-capital-unique-in-nature Y factors and the AltaGas AMR (automated meter reading) implementation Y factor are examples of this. There was some recognition by ATCO Gas,[718] ATCO Electric[719] and AltaGas,[720] that their proposed Y factor capital costs may not meet the typical criteria for assessing capital trackers or Y factors but they argued that the significance of the costs is so substantial that the projects can be justified on the basis of materiality alone given that there is an assumption that the projects are in the public interest.

584. The UCA recommended that these types of capital Y factors not be allowed on the basis that "[t]he creation of a flow-through shifts the risk to customers and is in violation of AUC Principle 1, that a PBR plan should incent behavior similar to a competitive market."[721] The CCA also expressed concern with the impact of these capital Y factors on the incentive properties of PBR, saying that "to the extent these costs are recovered as incurred, the de-linking of revenues from costs, being one of the foundations of any PBR plan, is weakened."[722]

585. Several companies requested capital Y factors for capital expenditures that are outside of the control of the company. Examples of this are the Fortis externally driven capital Y factor,[723] the ATCO Electric distribution contributions to transmission,[724] and the ATCO Gas transmission driven costs.[725] One of the arguments used to support the flow-through treatment of these particular capital costs was that utility companies have unique obligations to undertake such

715 Exhibit 631.01, ATCO Electric argument, Section 8.2, paragraph 125, page 35.
716 Exhibit 630.02, EPCOR argument, Section 8.2.1, paragraph 102, page 38.
717 Exhibit 631.01, ATCO Electric argument, paragraph 163, page 49.
718 Exhibit 632.01, ATCO Gas argument, Section 8.3, paragraph 190, page 61.
719 Exhibit 211.01, NERA-AE-17.
720 Exhibit 247.01, AUC-ALLUTILITIES-AUI-10.
721 Exhibit 634.02, UCA argument, Section 8.3, paragraphs 193 and 196, page 35.
722 Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 167, page 69.
723 Exhibit 100.02, Fortis application, Section 6.2, paragraphs 103-105, pages 29-30.
724 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 104-112, pages 6-6 to 6-7.
725 Exhibit 99.01, ATCO Gas application, Section 2.5.2.2, paragraphs 93-102, pages 34-36.

projects that a competitive firm would not encounter. Fortis explained that "as a result of its obligation to serve, FortisAlberta does not have the discretion to decline or delay such expenditures, unlike competitive firms."[726]

Commission findings

586. The Commission has determined that a mechanism to fund certain capital-related costs outside of the I-X mechanism through a capital factor is required. In the preceding sections the Commission has generally rejected the methodologies proposed by the companies for addressing this requirement. The Commission considers that the potential erosion of the incentive properties of PBR that arise from adopting the approaches to capital factors proposed by the companies are significant enough to warrant the use of the capital tracker approach to address special capital funding requirements. The Commission considers that the targeted criteria-based nature of a capital tracker limits the number of projects that are outside of the I-X mechanism, and as a result, the incentive properties of PBR are preserved to the greatest extent possible. Therefore, the Commission accepts that the use of capital trackers, as proposed by NERA and as recognized by several other parties as a viable option, is the best of the alternatives proposed for dealing with capital expenditures outside of the I-X mechanism. Accordingly, the Commission will include a capital tracker mechanism in the PBR plans.

587. A capital tracker mechanism in a PBR plan is warranted in circumstances where the company can demonstrate that a necessary capital replacement project or capital project required by an external party cannot reasonably be expected to be recovered through the I-X mechanism. The Commission concludes that a structured criteria-based approach provides the most objective method for assessing whether projects qualify as capital trackers.

588. Many of the proposals for capital factors in the form of K factors, the AltaGas MP factor, or Y factored capital expenditures are PBR plan variables that attempt to track the costs and corresponding revenue requirement of specific assets, and recover the revenue requirement outside of the I-X mechanism. Regardless of what a company originally called the capital factor variable, as long as the variable isolates the revenue requirement impact of the underlying qualifying assets (including depreciation, return on equity, cost of debt and income tax) to be incorporated into the PBR plan outside of the I-X mechanism, the factor is in the nature of a capital tracker and will be considered and tested as a capital tracker. The non-specific K factor proposed by EPCOR[727] is an obvious exception because it does not involve tracking specific capital assets. For consistency, all capital trackers will be recovered through a K factor variable in the PBR formula for all companies.

589. Dr. Makholm discussed the types of considerations the Commission should take into account in establishing the criteria for a capital tracker:

> Q Well, the incentive formula will produce a certain revenue stream and the incentives that result from the imposition of this regime will create savings through efficiencies through the company. So the effective revenue that a utility would have would be a mixture of the I minus X portion of the formula; it would be a function of growth in revenues, growth in customers, growth in revenues; a function of depreciation that has fallen off -- assets that are fully depreciated but yet the depreciation expense remains in rates. It would also be a function of all the efficiencies that can be achieved throughout

726 Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 76, page 14.
727 Exhibit 630.02, EPCOR argument, Section 8.1, paragraph 91, page 34.

the term. How does a regulator know when a ring fenced proposal for a tracker comes to them whether or not there's sufficient resources available through the operation of the PBR formula with all the incentives that are instilled through to it to cover the costs of that and how will they know when there isn't enough revenue to cover that?

A. DR. MAKHOLM: They'll know if the company can make good enough case that the derogation from a plan inherent in employing a tracker is genuine and worth the effort. And we have seen cases where that is the case, and one of them, a prime one, is cast iron pipe.

Q. We're all kind of dancing around the same question, but it's a very interesting discussion, so I'll try to advance it a bit further. So assume with me for a moment that a utility is able to put together the state of the art capital tracker application, ring fenced, engineering data to support it, and it has been doing that same type of activity for many years.

A. DR. MAKHOLM: Well, why then would they require a tracker if they've been doing that activity for many years? If they have been -- I don't mean to butt in, but if they have done, then that activity will be reflected in their base rates.

Q. And that's -- okay. So, in other words, it has to be something unusual, out of the normal course of the utility as opposed to what the industry group that formed the basis for the TFP study that carries on?

A. DR. MAKHOLM: Well, sure. Because everybody's rates are based on their own books and records in base rates, and if the company has been doing whatever it is that we're describing consistently over the course of many years, it's in their base rates, and hence the base rates ought to be able to reflect that capital expense. It's what isn't in base rates that's idiosyncratic and out of phase and deferred and lumpy that the formula wouldn't be able to cover, and that's the dividing line for derogating from a formula that's supposed to cover everything, is whether or not you decide by looking that there's a certain category of costs or a certain practical nature of any particular company's activities that lead it to conclude and convince the Commission that a straight-forward formula of the RPI minus X plus Z variety won't do.[728]

590. In an exchange with Calgary's counsel, Dr. Makholm clarified several qualifying criteria for capital trackers:[729]

Q. There was discussion yesterday with Mr. McNulty that these kinds of trackers would not – would not be or were not included in the base or the going-in rates; correct?
A. DR. MAKHOLM: Yes.
Q. And that they were idiosyncratic in nature. Yes?
A. DR. MAKHOLM: Yes.
Q. That, again referencing the between-rate-cases aspects, they were outside -- or were incurred outside of a rate case proceeding. Yes?
A. DR. MAKHOLM: Yes.
Q. They were incurred outside the ordinary course of business of the utility?
A. DR. MAKHOLM: Yes.

[728] Transcript, Volume 1, pages 160-163.
[729] Transcript, Volume 2, page 339.

Q. And they were incurred outside of or unrelated to past practices of the utility. Did I hear that right yesterday?
A. DR. MAKHOLM: Yes.
Q. Are there any others that I've missed?
A. DR. MAKHOLM: No, not that I can recall.

591. In addition to the criteria identified above, there was some discussion of other characteristics that should be exhibited by projects that qualify for special capital treatment. For projects to be considered atypical, NERA stated that the costs associated with the projects should be substantial.[730] NERA also suggested that any projects should be supported by an engineering analysis.[731] In addition, as stated by the CCA "investments to meet customer and load growth trigger revenue growth and are largely self-funding,"[732] therefore these projects should not be eligible for capital tracker treatment if they result in customer and load growth because the incremental costs should be funded by other features of the PBR formula.

592. Based on the foregoing, the Commission adopts the following criteria for capital trackers:

(1) The project must be outside of the normal course of the company's ongoing operations.

(2) Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.

(3) The project must have a material effect on the company's finances.

593. The Commission considers that the party recommending the capital tracker must demonstrate that all of the criteria have been satisfied in order for a capital project to receive consideration as a capital tracker. Accordingly, the Commission rejects the proposals to permit capital factors on the basis of materiality alone or on the basis that the project is externally driven alone, as was suggested by some of the companies proposing capital-related Y factors.

The project must be outside of the normal course of the company's ongoing operations

594. The first criterion is required to avoid double-counting between capital related costs that should be funded by way of a capital tracker and those that should be funded through the I-X mechanism. This criterion is also required to ensure that capital tracker projects are of sufficient importance that the company's ability to provide utility service at adequate levels would be compromised if the expenditures are not undertaken. Projects that do not carry this level of importance are likely subject to a reasonable level of management discretion, therefore allowing special treatment for this type of capital would eliminate the incentive for the company to examine all alternatives.[733] Therefore, this criterion would require that an engineering study be filed to justify the level of capital expenditures being proposed. That is, the company must demonstrate that the capital expenditures are required to prevent deterioration in service quality and safety, and that service quality and safety cannot be maintained by continuing with O&M and capital spending at levels that are not substantially different from historical levels. The company will also be required to demonstrate that the capital project could not have been undertaken in the past as part of a prudent capital maintenance and replacement program.

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730 Transcript, Dr. Makholm, Volume 1, page 171.
731 Transcript, Dr. Makholm, Volume 1, page 147.
732 Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.
733 Exhibit 634.02, UCA argument, Section 8.3, paragraph 196, page 36.

Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

595. The second criterion generally limits the scope of eligible capital projects to those required for replacement of aged infrastructure that has come to the end of its useful life and those that are required by third parties, such as projects ordered by government agencies. It excludes projects required to accommodate customer or demand growth because a certain amount of capital growth is expected to occur as the system grows and system growth generates new sources of revenue that offset the costs of the new capital. The new sources of revenue can come in the form of increased customers and load growth,[734] and also through contributions in aid of construction as prescribed by maximum investment level (MIL) policies.[735]

596. NERA stated that just because a capital expenditure is externally driven is not sufficient to justify a separate capital factor for it. Dr. Makholm identified the fact that even though it may be externally driven, the items may already be covered by the I-X mechanism if a similar level of costs is reflected in going-in rates.

> I would have to agree only on the condition that I've stated before, which is they're not reflected in the normal course of business reflected in the revenue requirement. They are specific and unusual enough to carve out and deal with separately. You have to appreciate our perspective, that for a distribution company everything is externally driven in one fashion or another. It's driven by the public services need for lights, and that the quantity of service that a utility provides isn't up to it; it's up to what the public requires, because all these distributors are set up to serve all-comers. So just saying externally driven doesn't do it for me. You would have to say externally driven, unusual enough not to be reflected in the cost of service as a going-forward exercise, and capable of being carved out as a limited feature so as not to disrupt unnecessarily the basic features of the PBR plan, which is to provide some regulatory lag and incentives.[736]

597. The UCA stated that externally driven capital expenditures do not meet the test of a capital tracker on the basis that the projects are not limited in nature, externally driven capital is included in going-in rates, the projects are not outside the ordinary course of utility business, and externally driven capital is related to the past practices of a utility.[737]

598. The CCA argued that supplemental capital expenditure funding may be required if it can be substantiated by solid evidence for investments "due to events beyond the utility's control such as highway relocations or the construction of a new transmission line."[738]

599. The Commission is aware that some of the capital costs for distribution utilities would otherwise not be required were it not for the activities of transmission or system operator entities or other external parties, and that the costs to the distribution utilities can be material and can vary significantly from year-to-year. Due to a company's obligation to provide service there is no opportunity for the company to turn down the project on the basis that company could not recover its costs because the project may not meet the capital tracker criteria, and therefore the company would be exposed to not receiving adequate compensation for undertaking the project.

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[734] Exhibit 636.01, CCA argument, Section 8.1, paragraph 117, page 46.
[735] Transcript, Volume 7, page 1310.
[736] Transcript, Dr. Makholm, Volume 2, page 330.
[737] Exhibit 634.02, UCA argument, Section 8.3, paragraph 199, page 36.
[738] Exhibit 636.01, CCA argument, Section 8.2, paragraph 122, page 50

600. Fortis indicated that the expenditures included in its Y factor for externally driven capital arise in the normal course of business.[739] While the obligations to perform the work exist for the companies, the Commission considers that a company must demonstrate that such costs are significantly different than historical trends to qualify for capital tracker treatment, otherwise there is a likelihood for double-counting.

The project must have a material effect on the company's finances

601. The third criterion is required to limit the use of capital trackers. NERA stated that the costs associated with capital trackers should be substantial due to the regulatory burden associated with the administration of the tracker.[740] The Commission considers that a utility may be frequently undertaking a number of small projects that may have the appearance of being atypical. However, the fact that the utility is undertaking a certain level of atypical projects on a consistent basis may result in that level of small unique projects being considered to be in the normal course of operations. The Commission also considers that it would not be suitable to group together several dissimilar projects into a single large project to give the appearance of materiality. However, a number of smaller related items required as part of a larger project might qualify for capital tracker treatment.

7.3.3 Implementation of capital trackers

7.3.3.1 Isolation of capital trackers from other fixed assets

602. The inclusion of capital trackers in the PBR plan presents a potential for double-counting if capital costs that should be funded by the I-X mechanism are also funded by the revenue provided through a capital tracker. To avoid the possibility of double-counting some parties proposed a method whereby the revenue requirement associated with historical costs (depreciation, return on capital and taxes) are removed from the going-in rates, thereby eliminating any possible impact of dealing with the capital tracker-related expenditures outside of the I-X mechanism.

603. Some of the proposed PBR plans proposed to isolate historical capital costs associated with certain capital expenditures for the PBR term. Fortis proposed to isolate the historical AESO contributions from going-in rates, and then take the revenue requirement associated with all AESO contributions to calculate that portion of its externally driven capital expenditures Y factor.[741] Fortis stated that it is not able to isolate the historical costs for the other types of capital expenditures that comprise the externally driven capital expenditures Y factor, due to the level of detail available in its asset ledgers.[742] AltaGas proposed a different form of adjustment to its major projects factor with the same underlying purpose, to avoid double-counting. To achieve this AltaGas proposed a reduction to the annual major projects factor calculation to exclude the revenue requirement impact associated with similar capital expenditures made between December 31, 2009 and December 31, 2012.[743]

604. Because capital trackers typically represent a surge in capital spending that will be followed by a period of slower than average capital spending, and therefore the company's future revenue requirements should be less than they otherwise would have been in the absence of the

[739] Exhibit 474.01, Fortis rebuttal evidence, Section 2.5, paragraph 73, page 14.
[740] Transcript, Dr. Makholm, Volume 1, page 171.
[741] Exhibit 100.02, Fortis application, Section 6.2, paragraph 105, page 30.
[742] Exhibit 222.17, CCA-FAI-8(b).
[743] Exhibit 110.01, AltaGas application, Section 6.0, paragraph 69, page 19.

capital tracker, there were some concerns raised over how long the projects should remain outside of the I-X mechanism. PEG suggested that if certain capital expenditures are excluded from the I-X mechanism in a PBR plan, then those capital expenditures should remain outside of the I-X mechanism in the next rate plan as well. PEG explained:

> The Y factoring of capex cost is sometimes advocated on the grounds that the capex in question is a one-time surge. To the extent that this is true, it should also be noted that the productivity growth of the company should accelerate once the surge is complete because the surge will cause the rate base to grow more slowly after it is completed. If PBR should accommodate a revenue surge now to help finance the capex, it should then reflect the slower revenue (requirement) growth that later results and thereby improve customer finances. One way to accomplish this is to have the costs of capex (e.g. depreciation and return) that are excluded from one indexing plan be recovered outside of indexing in the next rate plan as well.[744]

605. Other parties generally objected to this suggestion by PEG because it creates unnecessary complexity in subsequent PBR plans. These parties recommended that, the capital expenditures associated with the capital tracker should be included with the rest of rate base in the rebasing process.[745]

Commission findings

606. The Commission considers that the reduction to the capital tracker to eliminate the impact of similar expenditures included in going-in rates as proposed in the AltaGas major projects factor may be a reasonable method for addressing the issue of double-counting. However, the merits of any such proposal would need to be assessed as part of the approval process for individual capital trackers.

607. The Commission does not find that a company should remove the impact of historical costs associated with expenditures similar in nature to approved capital trackers from going-in rates as proposed by Fortis for its AESO contributions. The Commission considers that it is necessary to maintain the incentive properties of PBR to the greatest extent possible by keeping the maximum amount of capital expenditures subject to the I-X mechanism.

608. The Commission accepts the arguments that the complexity of isolating certain capital expenditures in perpetuity beyond the PBR term outweighs the benefits suggested by PEG. Therefore, the Commission requires that the revenue requirement impact of the capital tracker expenditures be recorded outside of the I-X mechanism only during the course of the current PBR term.

7.3.3.2 Method for determining capital tracker amounts

609. Some parties have objected to the use of capital trackers on the basis that they result in too much regulatory burden.[746] On the other hand, capital trackers are a reasonable method for retaining the efficiency incentive properties of PBR as discussed in Section 7.3.2.4.

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744 Exhibit 307.01, PEG evidence, Section 2.2.6, page 24.

745 Exhibit 631.01, ATCO Electric argument, Section 8.5, paragraphs 201-202, page 53; Exhibit 632.01, ATCO Gas argument, Section 8.5, paragraph 212, page 68; Exhibit 628.01, AltaGas argument, Section 8.5, page 43.

746 Exhibit 646.02, EPCOR reply argument, Section 8.1, paragraph 108, page 34; Exhibit 634.02, UCA argument, Section 8.4, paragraph 205, page 37.

Dr. Makholm stated that if a capital tracker is required to address the legitimate concerns of a company, the negative impact on administrative burden should not be a concern.[747] Given the criteria outlined for capital trackers in Section 7.3.2.4 it is clear that a relatively rigorous testing of capital trackers must occur.

610. Some of the companies have suggested that it would be administratively more efficient to not review the forecast for capital factors on an annual basis. The ATCO Electric K factor proposed to use forecasts at the outset of the PBR term that remain unchanged for the duration of the plan.[748] ATCO Electric and ATCO Gas suggested that not truing up the forecasts for capital factors introduces some superior incentive properties by allowing the companies to beat their approved forecasts.[749] The CCA supported the use of fixed forecasts on the basis that fixing the forecast would provide strong capital expenditure containment incentives. However, the CCA acknowledged that there would be an incentive for the companies to exaggerate their capital needs and therefore there would need to be a strong evidentiary record supporting the capital forecasts.[750]

611. Some of the companies suggested that their capital factors be reforecast periodically. Examples of this include the ATCO material-investments-unique-in-nature,[751] the Fortis externally-driven-capital Y factor,[752] and the AltaGas system reliability projects component of the major projects factor.[753] AltaGas also proposed a formulaic annual adjustment mechanism for the system safety projects component of its major projects factor.[754]

612. Another approach proposed to avoid the regulatory burden of reviewing forecasts is to only deal with capital trackers on a retrospective basis after the company has decided to proceed with the project and has made the capital expenditure. ATCO Gas proposed that this approach be used for its urban mains replacement (UMR) Y factor project.[755] Dr. Makholm suggested that a capital tracker should be based on items that are known and measurable rather than general forecasts to ensure that the tracker is specifically targeted.[756] Dr. Makholm suggested that if a tracker is limited to costs that are truly required to be recovered outside of the I-X mechanism, the efficiency incentives of a PBR formula will be lost.[757] Dr. Makholm explained one of the shortcomings of relying on capital forecasts is the incentive to overstate capital forecasts in saying:

> The other way is to find a formula that perhaps has incentives that are like the incentives in the UK that I described, that leave rise five years from now to the commission feeling that it's been hoodwinked with forecasts that haven't turned out to be what was actually spent. They may not have been hoodwinked, but how are you going to tell?[758]

747 Transcript, Dr. Makholm, Volume 3, page 506.
748 Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 39, page 13.
749 Transcript, Ms. Wilson, Volume 7, page 1280.
750 Exhibit 636.01, CCA argument, Section 8.3.2, paragraph 127, page 52.
751 Transcript, Ms. Wilson, Volume 4, page 759.
752 Transcript, Mr. Delaney, Volume 11, pages 2152-2154.
753 Exhibit 110.01, AltaGas application, Section 6.3, paragraph 78, page 22.
754 Exhibit 110.01, AltaGas application, Section 6.2, paragraphs 75-76, pages 21-22.
755 Exhibit 389.01, ATCO Gas application updates, Section 2.3, paragraph 12, page 7.
756 Transcript, Dr. Makholm, Volume 1, page 175.
757 Transcript, Dr. Makholm, Volume 1, page 168.
758 Transcript, Dr. Makholm, Volume 3, page 506.

Commission findings

613. The Commission acknowledges that a reduction in the frequency of capital reviews would achieve a reduction in administrative burden. In addition, the Commission acknowledges that the use of long term forecasts as proposed by ATCO Electric for its K factor does create some efficiency incentives. However, in the absence of a true-up, the Commission considers the incentives for a company to exaggerate its capital needs, as identified by the CCA, to be a major drawback to such an approach, and accordingly on that basis long term forecasts will not be used for capital trackers.

614. The Commission recognizes that superior efficiency incentives would be created if the companies were required to make capital investment decisions and undertake the investment prior to applying for recovery of their costs by way of a capital tracker. However, the Commission recognizes that parties and the Commission have very little experience with capital trackers and, therefore, will not require that this approach be used by the companies during the first PBR term.

615. Accordingly, unless a company chooses to undertake investment prior to applying for recovery of its costs by way of a capital tracker, the company will be expected to provide a forecast with its capital tracker application. The company will only be permitted to collect the forecast amounts for the capital tracker on an interim basis, and a true-up to the actual amount of the capital tracker will occur after the capital expenditures have been made. As a result, these companies will still have some efficiency incentives due to the risk of regulatory disallowances in the true-up process if expenditures are not prudently incurred.

7.3.4 Commission findings on the capital factors proposed by the companies

616. The capital projects proposed by the companies for capital factor or capital Y factor treatment may or may not satisfy the criteria for a capital tracker established by the Commission in this decision. Neither the companies nor other parties have had the opportunity to evaluate whether these projects satisfy the Commission's criteria. Accordingly, the Commission makes no finding as to whether any of the capital projects proposed by the companies satisfy the Commission's criteria. The companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission's capital tracker criteria

7.4 Y factor

617. In a PBR plan, Y factor costs are those costs that do not qualify for capital tracker treatment or Z factor treatment and that the Commission considers should be directly recovered from customers or refunded to them. Y factor costs in turn, could either be costs the company is required to pay to a third party (such as the AESO) or other Commission-approved costs incurred by the company for flow through to customers.

618. In Decision 2009-035 the Commission approved the flow-through of certain costs incurred by ENMAX along with the established collection of these costs outside the I-X mechanism. The Commission stated:[759]

> With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them. The Commission approves the following three items for flow-through treatment.
>
> - SAS rates in the distribution tariff
> - TAC Deferral Account
> - AESO load settlement costs

619. In Decision 2010-146[760] (the ENMAX compliance filing decision), the Commission approved the addition of the Commission's own administrative fee as a flow-through cost. Although not considered material, the Commission found it to be similar in nature to other flow-through amounts approved by the Commission.[761]

620. As a result of these criteria, under the ENMAX FBR plan, a cost might qualify to be collected as a flow-through cost outside of the I-X mechanism if the amount was foreseeable and regularly incurred in the normal course of business but the quantum and requirement to pay the cost was outside of the control of management. In addition, the amounts approved by the Commission should be material.

621. In this proceeding, each of the companies proposed the treatment of several accounts outside of the I-X mechanism. The companies designated all of these costs as Y factors. The Y factor accounts proposed by the companies substantially exceeded the number of flow-through items approved in Decision 2009-035.

622. The proposed Y factor costs included existing flow-through accounts similar to those approved in the ENMAX decision, deferral accounts that had been approved under cost of service rate regulation, new deferral accounts and unusual capital expenditures. The companies argued that all of these costs should be recovered as Y factors because these costs are highly volatile, recurring or have previously been approved by the Commission for flow-through treatment. More importantly, all of these costs were considered by the companies to be outside the funding capacity of the I-X mechanism.

623. In its review of these companies' Y factor proposals, NERA commented that the inclusion of a comprehensive set of deferral accounts was unusual in PBR plans,[762] and that an

759 Decision 2009-035, Section 9.3, paragraph 251, page 55.
760 Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010
761 Decision 2010-146, Section 9.1.1, paragraph s 97-100, page 16.
762 Exhibit 391.02, NERA second report, Section IV-D-2, paragraph 83, page 40.

overly broad set of Y factor accounts reduces efficiency incentives under PBR.[763] Interveners generally agreed with NERA's observations.

624. The CCA noted "that some utilities (most notably AE and AG) propose excessive use of Y factors."[764] The UCA recommended "that the ENMAX type flow-through items, like system access charges, AESO load settlement costs, transmission costs from upstream pipelines, the UCA assessment, the AUC assessment should continue as flow-through"[765] but objected to the wide use of deferral accounts. The UCA submitted that the Commission should not approve a number of the proposed Y factor accounts, stating that the Commission has previously ruled that deferral accounts should be approved only when they are demonstrably necessary.[766] IPCAA generally supported the recommendations of the UCA with respect to Y factors.[767] Calgary suggested that the ATCO Gas PBR plan should "retain the integrity of PBR through the reliance on the (I – X) mechanism, to the greatest extent possible."[768]

625. All of the companies commented that changes to their risk profiles could occur if deferral accounts that exist under cost of service were not continued as Y factors under PBR.[769] IPCAA also identified this as a factor to be considered.[770] The companies also expressed a preference for the use of Y factors instead of Z factors because of the greater uncertainty associated with approval of Z factors.[771]

626. Several parties suggested that the exogenous adjustment criteria approved in Decision 2009-035 could also be used to evaluate the deferral accounts proposed as Y factors under PBR.[772] While parties acknowledged the suitability of utilizing a set of criteria for evaluating Y factors, there was some discrepancy regarding how to apply the criteria. Some companies argued that Y factors should be approved if some, but not necessarily all, of the Y factor criteria were met. The criterion suggested by some of the companies as not needing to apply in all circumstances is the "outside-of-management-control" criterion.[773] Some interveners disagreed with the companies, and argued that items that are within management's control should not be eligible for Y factor treatment.[774]

763 Exhibit 391.02, NERA second report, Section IV-E-7, paragraph 113, page 51.
764 Exhibit 636.01, CCA argument, Section 10.1, paragraph 159, page 64.
765 Exhibit 634.02, UCA argument, Section 10.1, paragraph 231, page 41.
766 Exhibit 300.02, UCA evidence of Russ Bell, A20, page 23.
767 Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.
768 Exhibit 629.01, Calgary argument, Section 10.1, page 46.
769 Exhibit 476.01, ATCO Electric rebuttal evidence, paragraph 35, page 11; Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 28-29, page 8; Exhibit 473.02, EPCOR rebuttal evidence, A19, page 25; Exhibit 477.01, AltaGas rebuttal evidence, Section 7, paragraph 82, page 29; Exhibit 633.01, Fortis argument, Section 1.0, paragraph 36, page 9.
770 Exhibit 369.01, AUC-IPCAA-4.
771 Exhibit 633.01, Fortis argument, Section 10.5, paragraph 207, page 96; Exhibit 631.01, ATCO Electric argument, Section 10.4, paragraph 244, page 61; Exhibit 632.01, ATCO Gas argument, Section 10.5, paragraph 271, page 84; Transcript, Mr. Mantei, Volume 9, page 1550; Transcript, Mr. Gerke, Volume 11, page 1792.
772 Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a); The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.
773 Exhibit 211.01, NERA-AE-17; Exhibit 204.02, AUC-ALLUTILITIES-AG-11; Exhibit 248.02, AUC-ALLUTILITIES-AUI-10.
774 Exhibit 629.01, Calgary argument, Section 10.2, page 47; Exhibit 634.02, UCA argument, Section 10.1, paragraph 230, page 41.

Commission findings

627. There was no dispute among the parties that certain third party costs similar to those approved in Decision 2009-035 should qualify to be flowed through to customers. As well, most parties supported the flow through of costs similar to the Commission's administration fee.

628. The Commission agrees that the criteria approved in Decision 2009-035 should apply be to Y factor costs in this decision. The Commission agrees with parties that the types of third party flow-through costs approved in Decision 2009-035 should also be approved on a flow-through basis in this proceeding.

629. For Y factor costs that are not third party flow-through costs, some parties suggested that the deferral account criteria set out by the EUB in Decision 2003-100[775] be used as the criteria for approval.[776] In Decision 2003-100 the EUB stated:[777]

> The Board does not consider there to be a definitive Board policy regarding the use of deferral accounts. Rather, the Board's practice has been to evaluate the use of a deferral account on a case-by-case basis, on its own merit. The Board notes that ATCO Pipelines and the interveners suggested several criteria for the Board to consider in this situation including:
>
> - Materiality of the forecast amount,
> - Uncertainty regarding the accuracy and ability to forecast the amount,
> - Whether or not the factors affecting the forecast are beyond the utility's control,
> - Whether or not the utility is typically at risk with respect to the forecast amount.
>
> The Board notes that the criteria were suggested to address differing views with respect to risk, rate fluctuations, intergenerational inequity, and the Board's historical approach to deferral accounts. The Board considers that the suggested criteria are reasonable…

630. The criteria in Decision 2003-100 are similar to the exogenous adjustment criteria approved by the Commission in Decision 2009-035.[778] In both decisions the lists included criteria related to materiality and the events being beyond management's control. There was recognition from several parties that the exogenous adjustment criteria from Decision 2009-035 could be used to evaluate the deferral accounts proposed as Y factors under PBR.[779]

631. The ability to recover costs outside of the I-X mechanism should be an extraordinary remedy for cost recovery. If however, the company has no ability to influence the amount of certain costs and those costs are material in nature and not otherwise recoverable under the I-X mechanism, incentives are unaffected. Accordingly, the Commission adopts and clarifies the criteria established in Decision 2009-035 for the identification of eligible Y factor costs as follows:

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775 Decision 2003-100: ATCO Pipelines, 2003/2004 General Rate Application – Phase I, Application No. 1292783, December 2, 2003.

776 Exhibit 632.01, ATCO Gas argument, Section 10.2, paragraph 226, page 73; Exhibit 300.02, UCA evidence of Russ Bell, A20, page 22.

777 Decision 2003-100, Section 7.2.1, pages 115-116.

778 Decision 2009-035, Section 9.3, paragraph 247, page 54.

779 Exhibit 219.02, AUC-ALLUTILITIES-FAI-11; Exhibit 233.01, AUC-ALLUTILITIES-EDTI-11(a); Exhibit 248.02, AUC-ALLUTILITIES-AUI-11(a). The CCA suggests similar criteria in Exhibit 636.01, CCA argument, Section 10.2.1, paragraph 163, page 67.

1) The costs must be attributable to events outside management's control.
2) The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3) The costs should not have a significant influence on the inflation factor in the PBR formulas.
4) The costs must be prudently incurred.
5) All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

632. The Commission considers that all criteria must ordinarily be satisfied before a cost will be considered for Y factor treatment. In addition to those Y factors that meet the above criteria, the Commission will allow companies to recover as Y factor rate adjustments specific costs incurred at the direction of the Commission and flow-through costs that are similar in nature to the flow-through items approved for ENMAX in Decision 2009-035. The Commission considers that having fewer Y factor accounts will make the PBR plans easier to administer. Y factors will only be approved in circumstances where there is a demonstrable need for them.

633. The Commission acknowledges the arguments made by some parties that denying certain Y factor accounts could impact the risk profiles of the companies. The Commission addresses consideration of the potential for risk impacts of PBR in Section 7.4.2.6.1 of this decision.

7.4.1 Materiality of Y factors

634. The UCA recommended the disallowance of several Y factor accounts on the basis that the amounts associated with the accounts are not material. The UCA suggested that "only if a proposed deferral account is to account for the potential of an error in forecasting that could produce a gain or loss of substantial magnitude, should the Commission then use the other criteria to determine if deferral treatment is warranted."[780]

635. While most parties acknowledged that assessing the materiality of Y factors is appropriate, EPCOR disagreed stating that:

> EDTI's proposed Y factor does not include a materiality threshold limit. Such a threshold limit is not required as the deferral accounts and reserve accounts included in EDTI's Y factor are related to costs that are material. These deferral and reserve accounts have already been approved by the Commission using materiality as one of the criteria for approval. Generic proceedings do not require a materiality threshold as, if the subject matter of the proceeding were not material, the Commission would not hold a generic proceeding in relation to it.[781]

Commission findings

636. Due to the high degree of similarity in the purpose and assessment of Y factors and Z factors, unless otherwise determined by the Commission, the Commission considers that the materiality threshold established in Section 7.2.1 for Z factors should also apply to Y factors.

[780] Exhibit 300.02, UCA evidence, A20, page 23.
[781] Exhibit 237.01, CCA-EDTI-5.

7.4.2 Specific proposed Y factors

637. The companies proposed a variety of different Y factor accounts in this proceeding, some of which existed, as flow-through accounts and deferral accounts, prior to the implementation of PBR and others which are new. Interveners raised many concerns over the proposed Y factor accounts. In general, the objections raised by interveners were raised on the basis that the proposed accounts did not meet certain eligibility criteria.

638. The UCA provided many recommendations with respect to specific Y factor accounts in its evidence. Specifically the UCA recommended the denial of the following Y factors accounts proposed by the companies:[782]

- Variable Pay Program
- Expansion of Defined Benefit Pension plan
- Changes in Weather Deferral Account
- Changes in Load Balancing Deferral Account
- Production Abandonment Costs
- Distribution to Transmission Contributions
- Vegetation Management
- Head Office Cost Allocation Percentages
- AUC Rule 026 Deferrals-IFRS
- Exchange Rate Deferral
- Design, Development and implementation of a Demand Side Management (DSM) Program.
- ATCO Centre Calgary Lease.

639. Calgary only commented on ATCO Gas' accounts, and had a more general approach of only recommending the continued use of two deferral accounts with the belief that all other accounts are not appropriate to be used under PBR. Calgary recommended that only transmission costs and income tax deductible capital costs should be allowed.[783]

640. IPCAA recommended "that only those deferral accounts considered in the recent GCOC proceeding should be approved in this proceeding, in order to maintain consistency between the Commission's findings in the GCOC decision and the risk profile of the utilities."[784] In addition, in reply argument, IPCAA stated that it generally supported the UCA's arguments concerning all matters related to Y factor accounts (such as deferral accounts, reserves and flow-through items).[785]

641. The CCA provided a number of specific recommendations in its argument,[786] however several companies objected to the inclusion of the recommendations in argument on the grounds that the recommendations could not be properly tested due to the lateness of their introduction to the proceeding.[787] The Commission will only give weight to the CCA recommendations it

782 Exhibit 634.02, UCA argument, Section 10.1, paragraph 228, page 41.
783 Exhibit 629.01, Calgary argument, Section 10.1, page 46.
784 Exhibit 369.01, AUC-IPCAA-4.
785 Exhibit 642.01, IPCAA reply argument, Section 10.0, paragraph 13, page 2.
786 Exhibit 636.01, CCA argument, Section 10, pages 64-110.
787 Exhibit 644.01, Fortis reply argument, Section 1.0, paragraph 19, page 3; Exhibit 648.02, ATCO Gas reply argument, Section 10.2, paragraph 327, page 93; Exhibit 647.01, ATCO Electric reply argument, Section 1, paragraph 31, page 10.

determines are based on the prior record of the proceeding, and will not consider new proposals or supporting evidence that were introduced for the first time in argument.

Commission findings

642. The Commission has reviewed the various Y factor accounts requested by the companies, and has grouped the accounts into seven different categories:

(1) Accounts that should be approved for flow-through treatment on the basis that they are similar to the flow-through items approved for ENMAX based on the Commission's findings in Section 7.4 above.

(2) Accounts that are a result of Commission directions, and therefore are eligible for flow-through treatment even though they may not satisfy certain criteria for Y factors.

(3) Accounts that meet the Y factor criteria, and therefore are eligible for flow-through treatment.

(4) Events where the impacts are unforeseen, and therefore are better to be assessed as Z factors.

(5) Accounts that are not eligible for Y factor treatment because they do not satisfy the outside-of-management-control criterion.

(6) Accounts that are not eligible for Y factor treatment because they do not satisfy the inflation criterion.

(7) Accounts that involve capital expenditures and are therefore better to be assessed as capital trackers.

643. The Commission considers that in many cases companies have asked for Y factors that are common amongst them. Because these accounts can be grouped together, the Commission will assess groupings of similar Y factor accounts for several companies in the sections that follow.

644. Some of the companies withdrew their requests for certain Y factor accounts during the course of the proceeding.[788] Accounts that the companies have removed have not been included in the assessments in the following sections because it is assumed that the accounts will not be utilized during PBR.

[788] Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8 (withdrew deferral account for production abandonment costs and short term deferral accounts for IFRS implementation, NGTL/AP integration, Calgary head office lease); Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4 (withdrew deferral accounts for demand side management and natural gas system settlement code); Exhibit 633.01, Fortis argument, Section 10.2, paragraph 193, page 89 (withdrew exchange rate deferral account).

7.4.2.1 Accounts that are similar in nature to flow-through items approved for ENMAX

7.4.2.1.1 AESO flow-through items

645. All electric distribution companies accessing the electric transmission system in the province are charged by the AESO[789] for transmission services provided in relation to customers in their distribution service area. Accordingly, the distribution tariff of the electric distribution companies in this proceeding includes two components:[790]

- the distribution component, designed to recover the costs of owning and operating the distribution system; and
- the transmission component, designed to recover the AESO tariff charges to the distribution company.

646. ATCO Electric, Fortis and EPCOR indicated that while the rates covering the distribution component will be determined by the I-X mechanism, the AESO transmission access charges should be treated as flow-through items. The companies pointed out that the AESO charges have been subject to deferral account treatment under cost of service rate regulation and they proposed to continue using the existing deferral account mechanisms (with one modification, as further discussed below) to recover these costs under PBR. Historically, the companies used slightly different names for deferral accounts for the AESO charges, but the purposes for the costs are essentially the same:

Table 7-2 AESO flow-through items for electric distribution utilities

ENMAX[791]	ATCO Electric	EPCOR	Fortis
AESO load settlement costs	AESO load settlement costs[792]	AESO load settlement deferral account[793]	AESO load settlement cost reserve[794]
SAS rates in the distribution tariff	System access service payments[795]	System access service rates[796]	AESO system access service[797]
TAC deferral account		Transmission charge deferral account[798]	AESO charges deferral account[799]
Balancing Pool allocation refund rider	Balancing Pool adjustment[800]	Balancing Pool rider	Balancing Pool adjustment rider[801]

789 The AESO is a not-for-profit organization that plans and operates the transmission system in Alberta. http://www.aeso.ca/index.html.
790 Exhibit 633, Fortis argument, page 142.
791 Decision 2009-035, Section 9.3, paragraph 251, page 55.
792 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 119-122, page 6-10.
793 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.
794 Exhibit 100.02, Fortis application, Section 6.1.1, page 26.
795 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 92-103, pages 6-2 to 6-6.
796 Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.
797 Exhibit 100.02, Fortis application, Section 13.1, paragraph 160, page 45.
798 Exhibit 103.02, EPCOR application, Section 3.3, paragraphs 254-255, pages 81-82.
799 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 163-165, pages 46-47.
800 Exhibit 98.02, ATCO Electric application, Section 14, paragraph 265-266, page 14-2.
801 Exhibit 100.02, Fortis application, Section 13.1, paragraphs 166-168, page 47.

Commission findings

647. In Decision 2009-035, the Commission agreed with ENMAX that the company has no control over the AESO charges and approved flow-through treatment of these costs for the purposes of ENMAX's FBR plan.[802] All of the electric distribution companies are subject to the same types of costs and therefore the Commission considers that these costs satisfy the Y factor criteria enumerated above. The Commission also considers that achieving consistency with the flow-through items approved in the ENMAX FBR plan is fair and reasonable. Accordingly, the Commission finds that the AESO related cost items, as presented in Table 7-2 above, will be treated as flow-through items for the purposes of the PBR plans of Fortis, EPCOR and ATCO Electric.

648. To the extent that the companies have existing rider mechanisms to pass through these costs to customers, for billing consistency those existing mechanisms will continue under PBR.

7.4.2.1.2 Inclusion of volume variance in the transmission access charge deferral accounts

649. In their PBR proposals, the electric distribution companies proposed one modification to their existing transmission access charge deferral accounts. Currently, these deferral accounts reconcile only forecast to actual variances related to the AESO price changes. The companies bear the risk of forecast to actual variances related to transmission volumes (as measured by certain billing determinants such as metered energy, customer load, peak demand, etc.). In other words, if the AESO were to change its rates, the companies would be kept whole across its forecast volumes through a deferral account. However, the companies accept the risk of the actual volumes being lower or higher than forecast.[803] This arrangement can be generally represented as:

Transmission Access Deferral =
Forecast volume × (Actual AESO prices - Forecast AESO prices)

650. The companies indicated that they do not have any meaningful control over transmission volumes as they are completely driven by customer load requirements that can vary from year to year and month to month.[804] IPCAA agreed that the companies have "little if any control over customer loads."[805] IPCAA also observed that the only practical option to control transmission volumes can create risks that customer loads will be interrupted:

> Since utilities have and should have no direct control over customer load, their only practical option is to shift load between summer and winter peaking PODs [points of delivery] to minimize AESO tariff demand ratchets. Since distribution is largely radial in nature [Exhibit 306.01 page 2], this is rarely possible; urban utilities, with their denser service areas, are the only entities with meaningful substation switching options. However such switching creates significant risks that customer loads will be interrupted.[806]

651. Furthermore, the companies indicated that transmission volumes have become increasingly difficult to forecast due to a more complex AESO tariff structure. ATCO Electric

802 Decision 2009-035, paragraph 251.
803 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 95-97.
804 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 98; Exhibit 633, Fortis argument, page 142.
805 Exhibit 635, IPCAA argument, paragraph 99.
806 Exhibit 635, IPCAA argument, paragraph 102.

noted that the structure of the AESO's tariff has changed over the years shifting from energy related costs to demand-related costs which are more difficult to forecast.[807] In particular, ATCO Electric observed that the change in demand-related costs has increased from 42 per cent of the total AESO costs in 2004 to 78 per cent of the total system access service (SAS) costs.[808] Fortis shared these concerns.[809]

652. ATCO Electric and Fortis also expressed their view that the complexity of forecasting the transmission volumes will be more pronounced under PBR, since the companies will be forecasting billing determinants over longer periods of time (i.e., over the PBR term).[810] In that regard, Fortis submitted that in the absence of volume true-up, the company would need to update its transmission volumes forecast annually to effectively attempt to manage this transmission risk. In Fortis' view, this annual update was not consistent with "regulatory streamlining envisioned for PBR."[811]

653. Fortis also observed that one of the reasons the Commission relied upon for imposing volume risk on Fortis in Decision 2012-108[812] was that it might provide an additional incentive for the company to more accurately forecast its distribution billing determinants. In that regard, Fortis submitted that this determination was made in the context of a cost of service regime and would be less applicable to PBR. In Fortis' view, under PBR, forecasting of transmission volumes will be less critical in terms of sharing any risks between customers and the company.[813] ATCO Electric also agreed that the "circumstances associated with forecasting risk under PBR are significantly different than under cost of service regulation."[814]

654. Based on these considerations, EPCOR, ATCO Electric and Fortis proposed that their transmission access charge deferral accounts include both price and volume variances under PBR.[815] In other words, the companies requested that the AESO charges be treated as a full dollar-for-dollar flow-through item in their PBR plans. Under this arrangement, the actual transmission costs incurred will equal the actual transmission revenues received. This arrangement can be generally represented as:

Transmission Access Deferral =
(Actual volume - Forecast volume) × (Actual AESO prices - Forecast AESO prices)

655. The CCA noted that in two recent decisions, Decision 2011-375[816] and Decision 2012-108, the Commission determined that volume variances should not be included in the transmission cost deferral accounts in a cost of service rate design regime. In the CCA's

807 Transcript, Volume 4, pages 728-729.
808 Exhibit 631, ATCO Electric argument, paragraph 336.
809 Transcript, Volume 12, page 2243, lines 5-23.
810 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 99; Exhibit 633, Fortis argument, pages 143-144.
811 Exhibit 633.01, Fortis argument, pages 143-144.
812 Decision 2012-108: FortisAlberta Inc. Application for Approval of a Negotiated Settlement Agreement in respect of 2012 Phase I Distribution Tariff Application, Application No. 1607159, Proceeding ID No. 1147, April 18, 2012.
813 Transcript, Volume 12, page 2242, lines 5-16 and page 2244, lines 7-14.
814 Exhibit 639, ATCO Electric reply argument, paragraph 369.
815 Transcript, Volume 10, page 1874, lines 19-21 (EPCOR); Exhibit 633, Fortis argument, pages 143-144; Exhibit 631, ATCO Electric argument, paragraph 337.
816 Decision 2011-375: EPCOR Distribution & Transmission Inc. 2010-2011 Phase II Distribution Tariff Application, Application No. 1606833, Proceeding ID No. 980, September 15, 2011.

view, the Commission's determinations "apply as much in a cost of service environment as they do in the PBR regime."[817] Accordingly, the CCA argued that the companies' transmission access charge deferral accounts should continue to include price variance only.[818]

656. The UCA noted that in Decision 2012-108, the Commission indicated that it will "consider the merits of volume reconciliation for distribution utilities under the PBR regime in due course, following the issuance of a decision on Proceeding ID No. 566."[819] As such, the UCA recommended that the Commission continue with a generic proceeding for examining the issue of volume true-up as referenced in Decision 2012-108.[820]

657. IPCAA also noted the Commission's determination in Decision 2012-108 referenced by the UCA and recommended that the implementation of comprehensive PBR be delayed until incentives are developed that will encourage the distribution companies "to prudently minimize the transmission and distribution facilities installed in their service area."[821]

Commission findings

658. As observed by the UCA and IPCAA, in Decision 2012-108 the Commission reaffirmed its intention to consider the issues related to volume reconciliation under the PBR framework on a consistent basis for all distribution companies following the issuance of a decision in this proceeding.[822] However, having considered the evidence filed by the parties, the Commission agrees with Fortis' and ATCO Electric's view that a determination on volume reconciliation under PBR can be made in this proceeding.[823]

659. The Commission agrees with ATCO Electric's and Fortis' explanation that transmission volumes are driven by customer load requirements. Furthermore, as stated in a number of recent decisions, the Commission agrees with the electric distribution companies' assessment that they have no meaningful control over transmission volumes due to the specifics of the current structure of the AESO system access rates (more heavily oriented to demand-related charges versus energy-related charges) and the companies' limited ability to undertake seasonal switching of loads between points of delivery.[824] IPCAA came to the same conclusion.[825]

660. Nevertheless, analysing EPCOR's and Fortis' cost of service rate applications, the Commission concluded that these companies were able to forecast transmission volumes with reasonable accuracy, as demonstrated by relatively small volume variances in their respective deferral accounts.[826] However, in that case the companies were updating their billing determinants forecasts every two years, in their rate applications. The Commission agrees with ATCO Electric's and Fortis' arguments that the same level of precision will not likely be attainable if the companies will be forecasting their billing determinants for the duration of the

[817] Exhibit 636, CCA argument, paragraph 402.
[818] Exhibit 636, CCA argument, paragraphs 404-405.
[819] Decision 2012-108, paragraph 127.
[820] Exhibit 634.02, UCA argument, paragraph 433.
[821] Exhibit 635, IPCAA argument, paragraph 104 and Exhibit 642, IPCAA reply argument, paragraph 608.
[822] Decision 2012-108, paragraph 127.
[823] Exhibit 644, Fortis reply argument, paragraphs 182-183; Exhibit 639, ATCO Electric reply argument, paragraph 368.
[824] Decision 2011-375, paragraph 188 and Decision 2012-108, paragraph 115.
[825] Exhibit 635, IPCAA argument, paragraphs 99 and 102.
[826] Decision 2011-375, paragraph 189 and Decision 2012-108, paragraph 117.

PBR term. Therefore, the Commission will require the companies to file forecast billing determinants for the following year as part of their annual PBR rate adjustment filings.

661. More importantly, the Commission explained in recent decisions dealing with EPCOR's and Fortis' rate applications, that under a cost of service regulatory framework, the distribution revenue requirement established in Phase I applications is divided by the forecast billing determinants for the test period to design customer rates. In other words, the accuracy of customer rates and the companies' ability to recover their approved revenue requirement is highly dependent on the accuracy of their billing determinants forecasts.

662. Furthermore, under the current regulatory framework, the electric distribution companies accept the risk related to the difference between the forecast and actual billing determinants when recovering their approved distribution revenue requirement. In these circumstances, the Commission determined that under a cost of service rate making framework, the absence of volume true-up on transmission charges would provide a stronger financial incentive to the companies to accurately forecast their billing determinants to ensure reasonable recovery of both the distribution tariff revenue and transmission access charges. Overall, taking into account the impact of forecast billing determinants on customer rates and the companies' revenues, the Commission considers that under cost of service rate making, regulatory efficiencies stemming from a more rigorous billing determinants forecast outweigh the potential disadvantages of the companies bearing risk on transmission volumes.[827]

663. In contrast, under PBR, the companies' costs will not be driving their revenues. As set out in Section 4 of this decision, under the price cap plans approved for ATCO Electric, EPCOR and Fortis, customer rates for each year will be established by way of the I-X mechanism, regardless of a company's actual costs and the amount of energy transported through a company's system. In these circumstances, forecasting of billing determinants will have a minimal impact on customer rates.[828] As Fortis observed:

> And we would note that under PBR that all falls away. Under PBR we essentially have rates for the distribution component of costs increasing I minus X. We have billing determinant volumes growing on an actual basis, and the product of those two things are really the revenues that FortisAlberta will receive for its distribution service.[829]

664. Accordingly, the Commission agrees with Fortis' view that under PBR, there is no purpose for maintaining the true-up of transmission flow-through accounts of electric distribution companies limited to price-only.

665. IPCAA expressed concerns that the current deferral account mechanism creates "unnecessary cost uncertainty, delay, and administrative costs."[830] In that regard, as outlined in Bulletin 2012-04,[831] the Commission had initiated a review of the electric distribution companies'

[827] Decision 2011-375, paragraph 191 and Decision 2012-108, paragraphs 120-121.
[828] As set out in Section 4, under a price cap plan, billing determinants will be used nonetheless to apportion to customers other components of the PBR formula, outside of the (I-X) mechanism such as flow-through items, capital trackers, Z factors, etc.
[829] Transcript, Volume 12, page 2242, lines 5-16.
[830] Exhibit 635, IPCAA argument, paragraph 103.
[831] Bulletin 2012-04, Commission-initiated electric transmission quarterly rider process review, Proceeding ID No. 1678, March 29, 2012.

transmission quarterly rider mechanisms.[832] As part of that review, ATCO Electric, ENMAX, EPCOR and Fortis filed their applications to standardize their respective transmission access charge rider mechanisms. In the Commission's view, these applications address, among other things, the types of issues identified by IPCAA in this proceeding. For example, the companies are proposing to move to a prospective approach to setting their quarterly riders. Under this method, the transmission component of the companies' rates in any quarter will be reflective of the AESO charges in that particular quarter. As such, it will no longer be the case that transmission charges will be based on a calculation "whose results are unknowable until the utility releases them months after the fact."[833] Furthermore, the companies are proposing to standardize and simplify their quarterly riders, so that these applications can be reviewed with minimal scrutiny, reducing time delay and the administrative cost of dealing with these riders.[834] The Commission intends to address IPCAA's concerns in Proceeding ID No. 1678.

666. In light of the above considerations, the Commission approves the inclusion of volume variance in the transmission flow-through accounts of the electric distribution companies for the purposes of their PBR plans. The Commission expects that with this modification, the AESO related cost items will be dollar-for-dollar flow-through items in the companies' PBR plans. At the time of their annual transmission deferral reconciliation, the companies must ensure that the actual transmission revenues received equal the actual transmission costs incurred. As noted in the previous section of this decision, subject to this modification, the Commission directs Fortis, EPCOR and ATCO Electric to use their existing deferral mechanisms to flow through the transmission access costs to customers under PBR.

667. As indicated in Decision 2012-108, the Commission is committed to considering the issues related to volume reconciliation under the PBR regime on a consistent basis for all electric distribution companies.[835] The Commission considers that the same reasoning for including volume variances in ATCO Electric's, EPCOR's and Fortis' transmission charge deferral accounts under PBR applies to ENMAX as well. As such, the Commission directs ENMAX to bring this matter forward to the Commission as part of the next application dealing with the company's transmission access charge deferral account.

7.4.2.1.3 Transmission flow-through for gas utilities

668. The Commission considers that certain flow-through items requested by the gas companies serve a similar purpose, and have similar mechanisms to the AESO flow-through items approved for the electric distribution utilities. The transmission costs deferral account requested by ATCO Gas[836] falls into this category. ATCO Gas simply flows through the transmission rates charged by the transmission service provider to customers. ATCO Gas has requested volume variances to be included in this account under PBR for reasons that are similar to the electric distribution companies' requests to include volume variances in the transmission flow-through accounts. The Commission approves flow-through treatment using the existing rider mechanism for the transmission costs deferral account, and also approves the inclusion of volume variances in the account. AltaGas has also proposed to continue to address its gas procurement function and costs related to transportation by third parties separately from the

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832 Proceeding ID No. 1678.
833 Exhibit 635, IPCAA argument, paragraph 103.
834 Proceeding ID No. 1678, Exhibit23.02, Exhibit 24.01, Exhibit 25.01 and Exhibit 26.02.
835 Decision 2012-108, paragraph 127.
836 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, pages 24-25.

I-X mechanism through its existing gas costs recovery rate and third party transportation rate mechanisms.[837] The Commission approves AltaGas' treatment.

7.4.2.1.4 Farm transmission costs

669. Fortis intends to continue its existing practice of flowing through farm transmission costs to the AESO based on a prescribed formula.[838] Other flow-through items associated with AESO transactions have been approved as part of this decision, and it is therefore suitable for these costs to receive flow-through treatment.

7.4.2.2 Accounts that are a result of Commission directions

670. All of the companies included Y factor accounts or indicated the requirement for future Z factors related to future decisions issued by the Commission. The UCA acknowledged the need for a utility to have the opportunity to recover the costs related to changes in regulation.[839] As discussed in Section 7.4, an exemption to certain Y factor criteria will be permitted for certain cost items that have been incurred by a company in compliance with a direction of the Commission.

7.4.2.2.1 AUC assessment fees

671. In Decision 2010-146, the Commission approved flow-through treatment of AUC assessment fees for ENMAX under its FBR plan.[840] AUC assessment fees are common to all of the companies, and all of them asked for deferral or flow-through treatment of these fees.[841] Some of the companies did not request a specific flow-through account for these costs, as they had grouped these costs together with their hearing costs deferral account. The Commission will continue with flow-through treatment of AUC assessment fees. For those companies that included these fees in another deferral account with other types of costs, these companies are directed to separately identify the AUC assessment fees component in their Y factor calculations.

7.4.2.2.2 Effects of regulatory decisions

672. Several companies requested Y factors to flow through the impacts of regulatory decisions.[842] The Commission finds that regulatory efficiency would be achieved if the companies are able to treat the financial impact of items the Commission has already determined to be necessary as Y factor adjustments. The Commission therefore finds that the financial effects to companies that are clearly identified in a Commission direction may, with approval of the Commission, be included as Y factor adjustments in the annual PBR rate adjustment filings process. Specific changes related to generic cost of capital proceedings are discussed in Section 7.4.2.6.1 below.

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837 Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

838 Exhibit 100.02, Fortis application, Section 6.3, paragraphs 106-108, page 30.

839 Exhibit, 300.02, UCA evidence of Russ Bell, A21, page 33.

840 Decision 2010-146, Section 9.1.1, paragraph 100, page 16.

841 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 152, page 6-16; Exhibit 100.02, Fortis application, Section 6.1.3, paragraph 95, page 27; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23; ATCO Gas includes AUC administration costs in hearing costs according to Transcript, Volume 6, pages 918-919.

842 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 200-203, page 6-28; Exhibit 99.01, ATCO Gas application, Section 2.5.2.6, paragraph 108-109, page 38; Exhibit 100.02, Fortis application, Section 6.4.4, paragraphs 114-115, page 32; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.

7.4.2.2.3 Hearing costs

673. All of the companies requested Y factor treatment for hearing costs presently collected through their hearing cost deferral accounts.[843] The Commission considers that intervener costs approved to be paid pursuant to AUC cost decisions are a result of directions from the Commission, and therefore are eligible for collection through a Y factor adjustment. The Commission considers that management has a reasonable level of control over its internal hearing costs, and therefore the company portion of hearing costs will be subject to the I-X mechanism.

674. The company portion of the hearing costs that will be subject to the I-X mechanism will be the average awarded company hearing costs for the years 2009, 2010 and 2011. This amount will be included in going-in rates for the purpose of determining the rates for 2013 replacing the amounts presently included in the revenue requirement for 2012 for the hearing cost deferral account. Intervener costs will be treated as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.4 AUC tariff billing and load settlement initiatives

675. EPCOR included a Y factor for AUC tariff billing and load settlement initiatives.[844] The Commission considers that because these costs are a result of Commission directions they will be approved as a flow-through Y factor account to be reconciled in the annual PBR rate adjustment filings.

7.4.2.2.5 UCA assessment fees

676. The gas companies are required to make payments for UCA assessment fees. These are similar in nature to the AUC assessment fees and accordingly the Commission considers flow-through treatment to be warranted. The Commission understands that ATCO Gas included UCA fees as part of its hearing costs[845] and that AltaGas has requested a PBR deferral account that includes both AUC and UCA assessments.[846] To the extent that ATCO Gas and AltaGas included these fees in another deferral account with other types of costs, these companies are directed to separately identify the UCA assessment fees component in their Y factor calculations.

7.4.2.3 Accounts that meet the Y factor criteria and are eligible for flow-through treatment

677. The Commission has examined the following proposed Y factor accounts and finds that they satisfy the Y factor criteria established in Section 7.4 and therefore are eligible for flow-through treatment.

7.4.2.3.1 Municipal fees

678. Several companies indicated that they intend to continue with either a deferral account or flow-through treatment for franchise fees and property taxes. Fortis requested that its municipal

[843] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 152-155, page 6-16 to 6-17; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23; Exhibit 100.02, Fortis application, Section 6.1.3, paragraphs 95-96, pages 27-28; Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51; Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

[844] Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.

[845] Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.1, paragraph 58, page 23.

[846] Exhibit 110.01, AltaGas application, Section 7.1.1, paragraph 81, page 23.

franchise fee riders and its Rider A-1 municipal assessment riders continued.[847] Continuation of existing rider mechanisms to collect municipal fees was also proposed by ATCO Electric[848] and ATCO Gas.[849] In addition, EPCOR requested a property, business and linear tax deferral account.[850] Because these costs satisfy the Y factor criteria they will be treated as a flow-through item. Where there is an existing rider mechanism the companies are directed to use that mechanism and, in the absence of an existing rider mechanism, the companies will dispose of balances in a deferral account as part of the annual PBR rate adjustment filings process.

7.4.2.3.2 Load balancing

679. ATCO Gas requested continuation of its load balancing deferral account (LBDA). The UCA recommended the continued use of the load balancing deferral account, but recommended that ATCO Gas' suggestion to true-up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.[851] Because the account meets the Y factor criteria, the Commission determines that ATCO Gas may continue to use its load balancing deferral account in its current form. The Commission considers that the continued use of a threshold approach, as proposed by the UCA, is necessary to minimize the regulatory burden of reviewing applications. Therefore, during the PBR term, the existing process for dealing with the load balancing deferral account will continue as described by ATCO Gas where "the recovery or refund of the LBDA balance is triggered if either of the North or South accounts exceeds $5 million (receivable or payable) for six consecutive months, or if either account exceeds $10 million in any one month."[852] ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.3 Weather deferral

680. ATCO Gas requested continuation of its weather deferral account (WDA). The reduction to the risk that ATCO Gas faces with respect to weather was recognized in a previous GCOC proceeding in the form of a 100 basis points reduction to the equity thickness of ATCO Gas.[853] The weather deferral account not only protects ATCO Gas in years when its earnings would otherwise be negatively impacted by warmer than normal weather, but it also protects customers in years when colder than normal weather would require them to pay higher utility bills. The UCA recommended the continued use of the weather deferral account, but recommended that ATCO Gas' suggestion to true up the account every year instead of waiting until the account exceeds specified threshold levels should be denied.[854] Because the adjustment to risk has already been reflected in going-in rates, because the account meets the Y factor criteria, and because the account can have benefits for both the company and customers, ATCO Gas may continue to use its weather deferral account in its current form without annual true-ups. ATCO Gas described the current process as follows: "a WDA rate rider application is triggered to recover or refund the balance if and when either the North or South accounts is at or greater than $7 million

847 Exhibit 100.02, Fortis application, Section 13.1, paragraph 149, page 41.
848 Exhibit 207.01, AUC-BOTHATCO-AE-6.
849 Exhibit 206.02, AUC-BOTHATCO-AG-6.
850 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-1, page 51.
851 Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.
852 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.7, paragraph 72, page 28.
853 Transcript, Ms. Wilson, Volume 7, page 1321.
854 Exhibit 634.02, UCA argument, Section 10.1, paragraph 249, page 45.

(receivable or payable) on April 30 of each year."[855] ATCO Gas is directed to use a separate rider outside of the PBR formula to settle balances with customers.

7.4.2.3.4 Production abandonment

681. ATCO Gas withdrew its request for this account in its application update subject to the results of the review and variance on Decision 2011-450.[856] The issue is currently under consideration in other proceedings, and the Commission considers that in the interim this deferral account will continue as a Y factor. Pending the results of other proceedings reviewing the recoverability of production abandonment costs, the Commission will reassess whether the continuation of this Y factor under PBR is necessary. In the interim, while the issues around this deferral account are being addressed in other proceedings, ATCO Gas is directed to continue to track the balance associated with this deferral account. The settlement of the balance will not occur until the other proceedings have determined the proper treatment.

7.4.2.3.5 Income tax impacts other than tax rate changes

682. Several companies requested various income tax Y factor accounts. These accounts include:

- The income tax deductible capital cost deferral account and the deduction of deferrals for income taxes requested by ATCO Electric.[857]
- The income tax deductible capital costs requested by ATCO Gas.[858]
- The CRA re-assessment deferral and the income tax payable flow-through requested by Fortis.[859]
- The income tax timing differences flow-through account requested by AltaGas.[860]

683. The Commission will address the portion of the Y factor account relating to income tax rate changes in Section 7.4.2.6.2. All of the remaining income tax Y factor accounts relate to the treatment of temporary tax differences or the reassessment of prior income tax returns. The Commission understands that these types of adjustments only affect the earnings of regulated entities due to the use of the flow-through income tax method, and that most companies in other industries normalize their income tax expenses to reflect the impact of changes to future income tax liabilities and assets.

684. Calgary proposed that ATCO Gas should continue with deferral treatment for income tax deductible capital costs on the basis "that utility management cannot manage the level of expenditure for these items despite bona fide, competent and good faith efforts."[861] The UCA suggested that the continuation of income tax deferral accounts is appropriate, and noted that in

855 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.6, paragraph 69, pages 27-28.
856 Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.
857 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 123-145, pages 6-10 to 6-15, and paragraph 147, page 6-15.
858 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.8, paragraph 75, page 29.
859 Exhibit 100.02, Fortis application, Section 6.1.5, paragraphs 99-100, page 28 and Section 6.4.3, paragraph 113, page 32.
860 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
861 Exhibit 629.01, Calgary argument, Section 10.2, page 48.

Decision 2009-214,[862] the Commission expressed its intention to initiate a proceeding which will address consistent income tax methodologies for all utilities.[863]

685. As noted by the UCA, the Commission, in Decision 2009-214, indicated that it intends to initiate a proceeding which will address consistent income tax methodologies for all utilities. The Commission confirms its intention to initiate a generic income tax proceeding following the release of this decision. In the interim, the Commission considers that material changes in income tax expenses that result from the treatment of temporary tax differences or the reassessment of prior income tax returns should be passed on to customers until such time as any change in income tax methodology may be directed by the Commission. Accordingly, the income tax Y factor accounts respecting the treatment of temporary tax differences or the reassessment of prior income tax returns requested by ATCO Gas, ATCO Electric, Fortis and AltaGas are approved. These changes will be addressed through Y factor adjustments as part of the annual PBR rate adjustment filings.

7.4.2.4 Accounts that are unforeseen events, and therefore should be assessed as Z factors instead

686. The discussion on specific items in this section is not intended to obligate the Commission to approve Z factor treatment in future proceedings for any of the items discussed. This section simply identifies the types of items that have been proposed as Y factors by the companies, but which should be tested as Z factors because of their unforeseen and infrequent nature. When Z factor applications are submitted the merits of each item will be tested in detail as to whether or not they actually qualify. The following accounts fall into this category.

7.4.2.4.1 Self-insurance/reserve for injuries and damages

687. Fortis,[864] EPCOR,[865] ATCO Electric[866] and ATCO Gas[867] all requested that their self-insurance deferral accounts be continued as Y factors. While there may be some activity in these accounts on an annual basis, the primary purpose of these accounts is to capture the effects of major events that are not covered by insurance. The Commission considers that during the PBR term the significant events that the companies are concerned about could be addressed as Z factors while the non-significant events should be covered by the I-X mechanism. The Commission will allow the companies to include a provision in their going-in rates calculated as follows. The provision will be equal to the average value of each event that was included in their deferral account or as an adjustment to their reserve account for the most recent five-year period. This amount is to be reflected in the companies going-in rates. The companies are directed to identify this adjustment to going-in rates in their compliance filings and the Commission will make a determination in the compliance filing decision as to whether or not the adjustment is reasonable.

862 Decision 2009-214: ATCO Gas, 2008-2009 General Rate Application Phase I, Income Tax Module, Application No. 1553052, Proceeding ID. 11, November 12, 2009.
863 Exhibit 300.02, UCA evidence of Russ Bell, A21, page 30.
864 Exhibit 100.02, Fortis application, Section 6.1.4, paragraphs 97-98, page 28.
865 Exhibit 103.02, EPCOR application, Section 2.3.5, Table 2.3.5-2, page 51.
866 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 156-162, pages 6-17 to 6-18.
867 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.2, paragraph 59, page 24.

7.4.2.4.2 Depreciation rate changes

688. Fortis,[868] ATCO Electric,[869] ATCO Gas[870] and AltaGas[871] all requested Y factors related to depreciation changes. The companies requesting these Y factors indicated that depreciation studies do not occur on an annual basis. However, even when new depreciation studies are performed, it is not certain that significant changes in depreciation rates will result. If a substantial change does occur, the change may be a result of changes in management assumptions, which would cause the change to not be eligible for flow-through treatment in the form of either a Y factor or Z factor. However, if the change results from some circumstance that is outside of management control, the change may be eligible for Z factor treatment. Due to the unforeseeable nature of depreciation changes, the infrequent occurrence, and the uncertainty as to whether the changes would be eligible for flow-through treatment, depreciation changes will not be treated as a Y factor.

7.4.2.4.3 International Financial Reporting Standards (IFRS)/accounting changes

689. Fortis[872] and AltaGas[873] requested Y factor treatment for accounting changes. The Commission considers that impacts associated with major changes to accounting standards, whether it is the initial adoption of IFRS or any other modifications to accounting standards, should be infrequent. Other than the initial adoption of IFRS, it is unforeseeable when subsequent major changes to accounting standards will occur. In addition, Fortis recognized that the majority of the AUC Rule 026[874] changes it would need to make are required for financial reporting purposes, and that regulatory reporting would likely not be affected.[875] As a result, the Commission determines that because of the infrequent and unforeseeable nature of accounting changes, they should be assessed as Z factors.

7.4.2.4.4 Acquisitions

690. ATCO Electric,[876] ATCO Gas[877] and AltaGas[878] all requested several different types of acquisitions to be treated as Y factors including: REA acquisitions, gas co-op acquisitions, and municipal annexations. The UCA objected to the flow-through treatment of these accounts on the basis that a company should only make an acquisition when it is economically beneficial for the company to do so, and therefore allowing flow-through treatment is not necessary.[879] The Commission considers that under certain circumstances it may not actually be left to the discretion of management as to whether or not the acquisition is made. In those circumstances, it may be necessary to assess the impact of an acquisition through a Z factor application. Acquisitions within the control of management would not generally qualify as either a Z factor or a Y factor.

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868 Exhibit 100.02, Fortis application, Section 6.4.1, paragraph 110, page 31
869 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 194-195, pages 6-26 to 6-27.
870 Exhibit 99.01, ATCO Gas application, Section 2.5.2.4, paragraph 104, page 37.
871 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
872 Exhibit 100.02, Fortis application, Section 6.1.2, paragraph 92-94, pages 26-27.
873 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
874 Rule 026: *Rule Regarding Regulatory Account Procedures Pertaining to the Implementation of the Internal Financial Reporting Standards*, effective December 20, 20122 (Rule 026).
875 Transcript, Mr. Lorimer, Volume 11, page 2161.
876 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 191-191, page 6-26.
877 Exhibit 99.01, ATCO Gas application, Section 2.5.2.3, paragraph 103, page 37.
878 Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.
879 Exhibit 634.02, UCA argument, Section 10.1, paragraphs 277-282.

7.4.2.4.5 Defined benefit pension plan

691. In its 2010 Pension Common Matters application the ATCO utilities (ATCO Gas, ATCO Electric and ATCO Pipelines) applied for deferral account treatment for their pension expenses. In Decision 2010-189,[880] the Commission approved a deferral account for each ATCO utility to recover the special payments required to amortize an unfunded liability associated with the defined benefit portion of the Canadian Utilities Limited defined benefit pension plan.[881] In Decision 2010-553,[882] the Commission further explained that the purpose of the special payment deferral accounts is to capture the impact of timing differences that may arise between when special payment amounts are approved by the Alberta Superintendent of Pensions and consequently paid by the ATCO utilities and when amounts are approved by the Commission for inclusion in revenue requirement.[883] These differences were captured in a deferral account to keep both customers and shareholders whole.

692. ATCO Gas and ATCO Electric requested an expansion of their special payment deferral accounts by way of Y factor treatment associated with their defined benefit pensions plans.[884] AltaGas requested the creation of a pension deferral account with respect to their defined benefit pension plan costs.[885] These companies argued that when actuarial evaluations are made they can result in significant changes to the funding of the plan. Further, it is not simple to isolate changes resulting from special payment requirements resulting from an under funding of the plan from current service or other funding requirements.

693. The UCA recommended denial of the expansion of existing pension deferral accounts. The UCA referenced Decision 2010-189 where the Commission recognized the difference between special payments and current service pension costs, and the Commission determined that current service pension costs are no different than other compensation costs and therefore should not receive deferral treatment.[886]

694. The Commission agrees with the UCA that current service pension costs are no different from other compensation costs and accordingly denies the requested expansion of the ATCO Gas and ATCO Electric special payment deferral accounts and the creation of a pension deferral account for AltaGas.

695. With respect to the existing special payment deferral accounts of ATCO Gas and ATCO Electric distribution, the Commission considers that under a PBR environment there is no need to monitor the timing differences for which the deferral accounts were created. Accordingly, the existing special payment deferral accounts for ATCO Gas and ATCO Electric distribution will be discontinued upon implementation of PBR.

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880 Decision 2010-189: ATCO Utilities, Pension Common Matters, Application No. 1605254, Proceeding ID. 226, April 30, 2010.
881 Decision 2010-198, paragraph 94.
882 Decision 2010-553: ATCO Utilities, Compliance Filing Pursuant to Decision 2010-189, ATCO Utilities Pension Common Matters, Application No. 1606289, Proceeding ID. 693, December 1, 2010.
883 Decision 2010-553, Section 3.1, paragraph 17, page 4.
884 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 113-118, pages 6-8 to 6-10; Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.5, paragraphs 65-68, pages 26-27.
885 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
886 Exhibit 634.02, UCA argument, Section 10.1, paragraph 244, page 44.

696. In the event of a material change to a company's special payment obligations (either positively or negatively), a Z factor application would be available to address this change.

7.4.2.4.6 Insurance proceeds

697. ATCO Gas proposed a deferral account for insurance proceeds in compliance with AUC Rule 026.[887] The Commission considers that if an event involving insurance proceeds that would have a material impact on operating costs occurs, then ATCO Gas may apply for flow-through treatment as a Z factor.

7.4.2.5 Accounts that do not meet the outside-of-management-control criterion

7.4.2.5.1 Variable pay

698. ATCO Gas[888] and ATCO Electric[889] proposed the continued use of deferral accounts for variable pay and AltaGas proposed the continued use of its short term incentive plan deferral account as Y factors.[890] The UCA argued that variable pay is only one component of compensation and is subject to the same management control as all other components of compensation.[891] The Commission considers that companies should be left to develop employee compensation programs that will have the best impact on their performance, and therefore Y factor accounts related to variable pay are not approved. The Commission considers that such an approach complies with PBR Principle 1 that states that "a PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality."[892]

7.4.2.5.2 Vegetation management

699. ATCO Electric requested Y factor treatment for vegetation management costs on the basis that the costs are outside of the control of management because there are a limited number of contractors that do the work, and that competition for services significantly increases the rates that the contractors charge.[893] The UCA indicated that "the creation of a Vegetation Management deferral account reduces the incentive to find creative and innovative ways to manage this function, and reduce costs."[894] The Commission does not accept ATCO Electric's argument. Vegetation management costs are entirely within the control of management.

7.4.2.5.3 Head office allocation changes

700. ATCO Gas[895] and ATCO Electric[896] requested Y factor treatment for changes to head office allocation percentages. The UCA expressed concern about the possibility of cost shifting under PBR between affiliates and the companies and proposed that significant changes in corporate structure and affiliate agreements should be reviewed by the Commission and, if approved, the effects of the change should be flowed through to customers.[897] Several of the

887 Exhibit 389.01, ATCO Gas application updates, Section 2.4, paragraph 16, page 8.
888 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.3, paragraph 60, page 24.
889 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 148-151, page 6-16.
890 Exhibit 529.01, AltaGas corrections and amendments to application, Section 4, page 4.
891 Exhibit 634.02, UCA argument, Section 10.1, paragraph 243, page 44.
892 Bulletin 2010-20, Rate Regulation Initiative, Section 3, page 2.
893 Transcript, Mr. Freedman, Volume 4, page 755.
894 Exhibit 634.02, UCA argument, Section 10.1, paragraph 261, page 48.
895 Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 171-176, pages 6-20 to 6-22.
896 Exhibit 99.01, ATCO Gas application, Section 2.5.1.3.1, paragraphs 79-80, page 30.
897 Exhibit 634.02, UCA argument, Sections 11.3 and 11.4, paragraphs 299-309, pages 55-56.

companies indicated that they would be willing to apply for Commission approval of material changes to affiliate agreements.[898]

701. The Commission finds that head office allocations are not outside of the control of the companies' management or that of their parent company and do not qualify as a Y factor.

702. EPCOR's witness, Dr. Weisman, indicated that the exclusion of earnings sharing mechanisms from a PBR plan should eliminate the need for strict monitoring of affiliate transactions because the incentive to shift costs to affiliates to avoid sharing earnings is eliminated.[899] The Commission agrees. As the Commission has not approved earnings sharing mechanisms in this decision, the need to isolate changes to affiliate agreements in a Y factor account has been substantially mitigated. However, the Commission has approved re-opener provisions and an efficiency carry-over mechanism that rely on the calculation of a return on equity. Therefore, the companies are directed to file all new material affiliate agreements, material changes to affiliate agreements and significant changes to corporate structure that have a substantial impact on the operating costs of the company.

7.4.2.5.4 AMR implementation

703. AltaGas requested Y factor treatment for the implementation of AMR (automated meter reading). AltaGas believes that if it were to implement AMR during the PBR term that the payoff for the investment would not be possible during a single PBR term. The UCA objected to the inclusion of an AMR deferral account indicating that "[t]he type of innovation covered by AMR is the same type of efficiency gains that is intended by PBR Principle 1, that a PBR should provide the same incentives as a competitive market."[900] The Commission agrees. AMR should be undertaken only if it will achieve efficiencies that will outweigh the costs. This decision is not outside of management control. Therefore there is no need for Y factor treatment.

7.4.2.6 Accounts that do not meet the inflation factor criterion

7.4.2.6.1 Changes in the cost of capital

704. Some of the companies asked for a Y factor adjustment to rates to account for changes to the Commission approved rate of return on equity.[901] Fortis,[902] ATCO Gas[903] and ATCO Electric[904] requested a Y factor adjustment to recover the impacts of changes in financing rates (i.e., cost of debt).

705. In its GCOC decisions, the Commission establishes an approved ROE for the companies under its jurisdiction. As well, it has been the Commission's practice to account for the differences in risk among the individual companies by adjusting their capital structures (i.e., the

[898] Transcript, Ms. Wilson, Volume 4, page 780; Exhibit 384.02, AUC-ALLUTILITIES-FAI-25(b); Exhibit 381.01, AUC-ALLUTILITIES-AUI-25(a).
[899] Transcript, Dr. Weisman, Volume 9, page 1765.
[900] Exhibit 634.02, UCA argument, page 35, paragraph 193.
[901] Exhibit 98.02, ATCO Electric application, page 6-28, paragraph 202; Exhibit 99.01, ATCO Gas application, page 38, paragraph 109; Exhibit 100.02, Fortis application, page 32, paragraph 114; Exhibit 103.02, EPCOR application, page 51, table 2.3.5-2; Exhibit 110.01, AltaGas application, page 24, paragraph 82.
[902] Exhibit 100.02, Fortis application, Section 6.4.2, paragraphs 111-112, pages 31-32.
[903] Exhibit 99.01, ATCO Gas application, Section 2.5.2.5, paragraphs 105-107, pages 37-38.
[904] Exhibit 98.02, ATCO Electric application, Section 6, paragraphs 196-199, page 6-27.

ratio of equity to debt).[905] Under cost of service regulation, the Commission approves a forecast of the company's cost of debt in its revenue requirement.

706. Both the I and the X in the PBR formula apply to the companies' distribution rates that are established through a cost of service proceeding. All of the distribution costs that are recovered through those rates, including the cost of debt and the cost of equity, are included in the going-in rates. In Section 5.2.1 of this decision the Commission determined that changes in the cost of capital (both debt and equity) are captured in the approved I factor. This means that the approved I factor in the I-X mechanism reflects changes in all of the companies' costs over time, including the cost of debt and equity. Therefore, the Commission finds that no specific changes to customer rates should be made to take into account changes in the Commission's approved generic ROE or changes in the cost of debt during the PBR term.

707. The Commission agrees with Dr. Lowry when he stated:

> But the one that raises an eyebrow to me in this category is the financing of – financing rate changes. I have never seen a plan involving an index that also involves an adjustment for financing rate changes. You would think that the – there is a danger of double-counting of that since [if] there is a change in interest rates eventually it will have an effect on general inflation rates. And this is particularly so inasmuch as the other – the second inflation measure proposed by ATCO Gas is the CPI for Alberta…[906]

708. It follows that including a separate flow-through component for changes in the ROE would also amount to double-counting.

709. The Commission recognizes that the conclusions it has reached with respect to the treatment of the cost of equity in the PBR framework are different than the approach taken by the Commission in the ENMAX FBR framework. The Commission has benefited from the evidence and testimony on this matter that was not available to it in the ENMAX FBR proceeding.

710. The Commission understands that a change to the risk profile of the companies may result from the transition to PBR. The Commission will consider this issue in the upcoming GCOC proceeding. If the Commission determines that there is a change to the risk profile of the companies as a result of the transition to PBR, the Commission will make a one-time adjustment to the companies' rates to reflect any adjustment to the companies' capital structure.

7.4.2.6.2 Income tax rates

711. ATCO Electric[907] proposed Y factor treatment to recover any changes to income tax rates. AltaGas' witness, Mr. Retnanandan, discussed why AltaGas would not try to recover the impact of tax rate changes from customers, stating "potentially on the PBR, the changes in tax rates would be covered under something like the inflation factor. So that would be duplicating, if you would, to recognize the income tax rate changes as part of the AUI Z factors."[908] The Commission considers that major changes to the calculation of income tax payments, such as a change in income tax rates, should impact the entire economy, and as such, should be captured

[905] See for example, Decision 2011-474: 2011 Generic Cost of Capital, Application No. 1606549, Proceeding ID No. 833, December 8, 2011, paragraph 169.
[906] Transcript, Volume 14, pages 2660, line 18 to page 2661, line 2.
[907] Exhibit 98.02, ATCO Electric application, Section 6, paragraph 146, page 6-15.
[908] Transcript, Mr. Retnanandan, Volume 9, page 1614.

by the I factor. To the extent that a change could occur that only impacts a select group of companies, and therefore not be captured by the I factor, it may be warranted to consider the change as a Z factor. However, due to the infrequent nature of such changes, it is not necessary to establish a Y factor account.

7.4.2.7 Requested capital project Y factors

712. Some items classified as Y factors by the companies relate to specific capital programs that may or may not proceed at some point during the PBR term that the companies considered to fall outside of the revenues that would be available to fund the project through the application of the I-X mechanism and customer growth. These proposed Y factors are listed in the following table.

Table 7-3 Capital-related flow-through items requested by utilities

AltaGas	ATCO Electric	ATCO Gas	EPCOR	Fortis
n/a	Material investments unique in nature	Material investments unique in nature	n/a	Externally driven capital expenditures
n/a	Distribution to transmission contributions	Transmission driven costs (capital component)	n/a	n/a
n/a	n/a	Urban mains replacement expenditures	n/a	n/a

713. The Commission considers that eligibility for these capital-related items should be assessed by way of a capital tracker application. See Section 7.3.2.4.

7.4.3 Collection mechanism for third party flow-through items

714. For flow-through items that have existing rider mechanisms in place, the companies generally suggested the continuation of the existing mechanisms. The changes to the rate riders associated with these mechanisms are separate from the rate adjustments resulting from the I-X mechanism. Due to the material nature of costs and the processes that are already in place for certain flow-through items, true-ups may be required more frequently than the annual PBR filings. One example is quarterly applications for SAS (system access service) riders. Some other flow-through items have traditionally been structured to have less than annual true-up mechanisms to avoid frequent true-up applications. Examples include the load balancing deferral account and weather deferral account for ATCO Gas. These deferral accounts have historically relied on a threshold triggering mechanism to determine when applications are submitted.

715. The companies proposed the continuation of several existing riders outside of the I-X mechanism:

- Fortis proposed to continue to use its transmission adjustment rider to flow through AESO charges, Rider A-1 Municipal Assessment Rider, Municipal Franchise Fee Riders, and the Balancing Pool Allocation Rider.[909]
- EPCOR proposed to continue to deal with its SAS rates and its transmission charge deferral account through separate applications.[910]

[909] Exhibit 100.02, Fortis application, Section 13.1, paragraphs 148-149, page 41.
[910] Exhibit 103.02, EPCOR application, Section 3.3, paragraph 255, page 82.

- ATCO Electric proposed continued use of its Rider S for its SAS deferral account.[911]
- ATCO Gas proposed to recover its transmission costs through its existing Rider T mechanism.[912]
- AltaGas proposed to continue to address its gas procurement function and costs related to transportation by third parties through its existing gas costs recovery rate and third party transportation rate mechanisms.[913]

Commission findings

716. The Commission considers that to the extent there are existing processes in place that are working well for addressing changes to the approved flow-through items, and those processes do not correspond to the timing of the annual PBR rate adjustment proceedings, these applications should continue to be dealt with as they are today.

7.4.4 Collection mechanism for other Y factor amounts

717. Unless otherwise directed, all Y factor costs incurred by a company other than the flow-through accounts that are collected through separate rate riders addressed in sections 7.4.2.1 and 7.4.2.3 above should be tracked and settled as a Y factor adjustment in its annual PBR rate adjustment filings.

718. The Y factor portion of the annual PBR rate adjustment filings will be comprised of two parts, the first being a provision for the Y factor amounts to be included in rates for the upcoming year, and the second being a true-up between the provision included in rates for the Y factor in the prior year and the actual amounts incurred in the prior year.

719. The provision for the first year of the PBR term which will be included in the compliance filing to this decision will generally be based on the amount that would have been approved for the 2012 test year of the GTA or GRA proceeding that forms the going-in rates (unless a different amount is specified elsewhere in this decision). Because these items will not be subject to the I-X indexing, the companies are directed to remove the amounts included in the 2012 revenue requirement from going-in rates in their compliance filing.

720. The Commission recognizes that addressing the impact of certain Commission directions impacting rates may be better suited to an adjustment to the rates that will be subject to the I-X mechanism rather than through a Y factor. The Commission will make the determination of how to incorporate the result of any directed rate adjustment at the time it makes the relevant decision.

721. The Commission also recognizes that some of the companies may have placeholders in place for certain expenses as part of the GTA or GRA proceedings that form the going-in rates for PBR. To the extent that other proceedings in front of the Commission will establish the approved expenses, and the companies will need to adjust their going-in revenue requirements, the Commission considers that the differences that exist between the placeholder amounts and the final approved amounts will be treated as Y factor adjustments or adjustments to rates that will be subject to the I-X mechanism, depending on the circumstances of the adjustment.

911 Exhibit 98.02, ATCO Electric application, Section 6, paragraph 101, page 6-5.
912 Exhibit 99.01, ATCO Gas application, Section 2.5.1.2.4, paragraph 64, page 25.
913 Exhibit 110.01, AltaGas application, Section 1.1, paragraph 9, page 3.

7.4.5 Other existing deferral accounts, reserve accounts or flow-through mechanisms

722. Companies may not have identified all of the items they plan to flow through to customers in their PBR plans. For example ATCO Gas and ATCO Electric did not mention the continued use of existing riders to collect franchise fees and property taxes in their applications, but clarified that the existing treatment would continue in IR (information request) responses.[914] Similar omissions may have occurred for other PBR proposals because of assumptions made by the companies that the existing treatments will continue. Therefore, the Commission directs the companies to identify all of the riders that they intend to utilize during the PBR term that are outside of the I-X mechanism, describe the costs that are being collected on the riders, and explain why it is reasonable to continue to flow through the costs. Any items that have not been approved as a Y factor in this decision or are not identified as separate riders outside of the I-X mechanism by the companies in their compliance filings will be subject to the I-X mechanism.

8 Re-openers and off-ramps

723. A re-opener serves as a safeguard against unexpected results in the event that there is a problem with the design or operation of the plan that makes its continued operation untenable. All of the companies proposed that their PBR plans include a re-opener. As well, Calgary proposed a re-opener for ATCO Gas.[915]

724. An off-ramp is likewise intended to provide a safeguard against unexpected results in the operation of the PBR plan. Proponents of an off-ramp distinguished it from other forms of re-openers; arguing that once triggered, an off-ramp allows for the whole of the PBR plan to be examined and possibly terminated, whereas a re-opener is generally intended to provide an opportunity to investigate and modify a particular component in the operation or design of the PBR plan.[916] NERA stated that re-openers and off-ramps are common features of incentive plans and recommended their inclusion.[917]

725. As with the ENMAX FBR plan, EPCOR and AltaGas distinguished between unforeseen events that impact one or more elements of a PBR plan (to be considered by way of a re-opener) from events that jeopardize the PBR plan in its entirety (to be considered by way of an off-ramp) and accordingly both proposed separate re-opener and off-ramp. The UCA and the CCA simply urged the Commission to adopt the off-ramp that was approved for ENMAX in Decision 2009-035.

726. Fortis, ATCO Electric and ATCO Gas did not include specific off-ramp proposals in their respective PBR plans.[918] They instead proposed that provisions for a re-evaluation of their entire PBR plans be addressed as part of the process for re-opening and reviewing a PBR plan, if necessary. Fortis also noted that any "event material enough to merit consideration as to plan

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914 Exhibit 207.01, AUC-BOTHATCO-AE-6; Exhibit 206.02, AUC-BOTHATCO-AG-6

915 Exhibit 298.02, Calgary evidence, page 29.

916 Exhibit 103.02, EPCOR application, page 77; Exhibit 634, UCA argument, page 58 (taken from Exhibit 228.01, page 55).

917 Exhibit 391.02, NERA second report, page 48, paragraph 104.

918 Exhibit 631.01, ATCO Electric argument, paragraph 265; Exhibit 632.01, ATCO Gas argument, paragraph 290; Exhibit 633.01, Fortis argument, paragraphs 228-229

change or potential termination could be brought forward under a Z factor application."[919] The UCA, the CCA and IPCAA all supported the inclusion of a re-opener. With respect to off-ramps, Calgary[920] agreed with the approach advanced by ATCO Gas.

Commission findings

727. A re-opener is commonly included in a PBR plan in order to address specific problems with the design or operation of a PBR plan that may arise or come to light as the term of the PBR plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. No party recommended proceeding with a PBR plan without including the facility for a re-opening and review of the plan if it is determined that there may be a problem with the plan. The Commission agrees that a facility to re-open and review the plan is a necessary element of any PBR plan.

728. However, the Commission agrees with Fortis, ATCO Electric and ATCO Gas that a specific facility for an off-ramp, as distinct from a re-opener, is not required in a PBR plan. All that is required, in the Commission's view, is an opportunity to re-open and review a PBR plan if a design or application flaw comes to light during the term of the PBR plan.

729. Accordingly, the Commission finds that any party, including the Commission on its own motion, will be permitted to bring an application to re-open and review a PBR plan, if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan. In this regard, the Commission has approved in the PBR plans a number of mechanisms, including Z factors, K factors and various Y factors that allow for adjustments to rates outside of the adjustments required by the application of the I-X mechanism.

8.1 Specific proposals for re-openers

730. Parties to the proceeding proposed a number of events that should, in their view, lead to a re-opening and review of a PBR plan. The Commission has considered each of these events and made a determination as to whether each constitutes sufficient evidence that there is a problem with a PBR plan that can only be remedied by re-opening and review the plan.

731. Both the UCA and the CCA recommended that the Commission adopt a re-opener and proposed that the events leading to a re-opener as approved for ENMAX in Decision 2009-035 be adopted in this decision. In Decision 2009-035, the Commission accepted that the following events would generally require a re-opening of the ENMAX plan: if circumstances changed in a substantial or unforeseen manner; changes in regulatory status; changes to ENMAX's controlling ownership; or a misrepresentation by ENMAX.[921] With regard to specific events that would require a re-opening and review of the ENMAX plan, the Commission accepted the following: a failure to meet a specific performance standard for two consecutive years; material changes in accounting standards that have an annual impact greater than $5 million; expansion of ENMAX's service area where more than 10,000 customers are included within the expanded area; ROE results that are more than 300 basis points above or below the approved ROE for two

[919] Exhibit 633.01, Fortis argument, page 102.
[920] Exhibit 629.01, Calgary argument, page 54.
[921] Decision 2009-035, page 50

consecutive years; and an actual ROE result that is 500 basis points above or below the approved ROE for one year.[922]

732. Additionally, the CCA requested that, in the event that EPCOR's parent acquired additional businesses which had an impact on the amount of shared services allocated to EPCOR, a deferral account should be established and that it should not be included as a re-opener.[923] IPCAA specifically proposed that a re-opener should address any material degradation in customer service and urged the Commission to establish service quality standards in advance of any implementation of a PBR plan.

733. For ease of reference, the events that were proposed by each distribution company and by Calgary as evidence that a PBR plan should be re-opened and reviewed are set out in the table below:

Table 8-1 Summary of proposed re-opener mechanisms

	Fortis[924]	EPCOR[925]	ATCO Electric	AltaGas[926]	ATCO Gas	Calgary
ROE Re-opener	ROE before ESM is +/- 300 basis points above or below approved ROE.*	ROE is +/- 300 basis points* above/below approved ROE in two consecutive years. OR Actual ROE is +/- 500 basis points above/below approved ROE for one year.	If ESM, ROE before ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE.*[927]	Actual weather normalized ROE is +/- 300 basis points above/below approved ROE in two consecutive years. OR Actual ROE is +/- 400 basis points above approved ROE for one year.	If ESM, actual ROE after ESM is +/- 300 basis points above/below approved ROE. OR If no ESM, actual ROE is +/- 300 basis points above/below approved ROE. Actual ROE will be normalized. If no weather deferral account or if weather deferral account is a Z factor, then use actual ROE.[928]	Actual ROE is 300 basis points below approved ROE.
Default supplier Re-opener			Directed to resume role of default energy supplier.[929]	Material change in the default supply regulations.	Directed to resume role of default energy supplier.[930]	

[922] Decision 2009-035, page 50.
[923] Exhibit 636.01, CCA argument, at paragraphs 331-333.
[924] Exhibit 100.02, Fortis application, page 35, paragraphs 126.
[925] Exhibit 103.02, EPCOR application, page 79, paragraph 241.
[926] Exhibit 110.01, AltaGas application, page 27, paragraph 87.
[927] Exhibit 292.01, AUC-ALLUTILITIES-AE-16.
[928] Exhibit 632.01, ATCO Gas argument, page 88, paragraph 285.
[929] Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.

	Fortis[924]	EPCOR[925]	ATCO Electric	AltaGas[926]	ATCO Gas	Calgary
Customer size/service area Re-opener		Expansion of service area of more than 10,000 additional customers in expansion area.	Loss of a franchise resulting in loss of 20,000 or more customers.[931]	Loss of 1000 service sites, excluding service site additions.	Loss of a franchise resulting in loss of 20,000 or more customers.[932]	
Accounting standard Re-opener		Material changes in accounting standards causing an annual impact on total revenue or expenses of >$2.5 million in aggregate in any one year.				
Service quality Re-opener		Failure to meet service quality performance target for two consecutive years.				
Cost of debt Re-opener				Spread between the embedded cost of debt and the I factor is ≥400 basis points.		
Z factor Re-opener				Cumulative, net, annual impact of Z factors on actual weather normalized ROE is ≥ ± 75 basis points in a single year.		
Management structure Re-opener				Material change in the management structure of AltaGas.		

* Approved ROE is the ROE approved by the Commission, generally in a generic cost of capital decision; most recently in Decision 2011-474.

930 Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.
931 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 234.
932 Exhibit 99.01, ATCO Gas application, page 43, paragraph 124.

734. Additionally, and for ease of reference, the specific events that were proposed to initiate an off-ramp proposed by EPCOR, AltaGas, the UCA and the CCA are set out in the table below:

Table 8-2 Summary of proposed off-ramp mechanisms

Proposed off-ramp	EPCOR[933]	AltaGas	ENMAX off-ramps supported by CCA[934] / UCA[935]
Substantial change in circumstances	Substantial and unforeseen change in circumstance that renders continuation of PBR unjust or unreasonable. A substantial change in circumstance is defined as a change that increases distribution or transmission costs by $1 million or $0.50 million, respectively and these costs cannot be addressed as a Z factor.		Circumstances change in a substantial or unforeseen manner.
Regulatory status	Change in regulatory status if EPCOR no longer regulated by the Commission or a successor of the Commission.		Change in regulatory status.
Change in tax status	Change that results in a change in EPCOR'S taxable status.		
Change in control		Sale in controlling interest of AltaGas shares or disposition of all assets.[936]	Change in control.

Commission findings

735. In keeping with the Commission's finding that a specific facility for an off-ramp (as distinct from a re-opener) is not required in a PBR plan, the Commission will consider together the proposals made by parties for events that would result in either a re-opener or an off-ramp and determine whether each of these is sufficient to result in a re-opening and review of a PBR plan.

8.1.1 Return on equity

736. Common among the companies and the interveners were proposals to re-open and review a PBR plan if the actual ROE earned by a company exceeded the approved ROE by more than a pre-determined amount and, in some cases, fell below the approved ROE by a pre-determined amount.[937] It was generally argued that earning an actual ROE that is 300 basis points above or below the approved ROE is a sufficient indication that the PBR plan should be re-opened and reviewed. However, the parties differed as to whether the 300 basis point variance needed to be

933 Exhibit 103.02, EPCOR application, page 77.
934 Exhibit 636.01, CCA argument, page 115.
935 Exhibit 634.01, UCA argument, page 57, paragraph 320.
936 Exhibit 628.01, AltaGas argument, page 64.
937 Exhibit 98.02, ATCO Electric application, page 10-1, paragraph 233; Exhibit 99.01, ATCO Gas application, page 42, paragraph 123; Exhibit 100.02, Fortis application, page 36, paragraph 126; Exhibit 103.02, EPCOR application, page 79, paragraph 241; Exhibit 110.01, AltaGas application, page 27, paragraph 87; Exhibit 298.02, Calgary evidence, page 48, paragraph 169; Exhibit 634.02, UCA argument, page 58, paragraph 321; Exhibit 636.01, CCA argument, pages 112-113, paragraph 326.

recurring and whether the application of the measure should be symmetrically applied to both over and under-earning. EPCOR also proposed that a 500 basis point variance in one year should result in a re-opening of a PBR plan.[938]

Commission findings

737. The Commission finds that a material variance in the actual ROE achieved by a company when compared to the approved ROE may be an indicator that a PBR plan should be reviewed. The Commission expects that earnings may fluctuate from year to year and therefore finds that an earned ROE 300 basis points above or below the approved ROE in a single year is not sufficient evidence, on its own, that a PBR plan should be reviewed. However, the Commission does agree with the proposal of the CCA and EPCOR that an earned ROE that is 500 basis points above or below the approved ROE in a single year is sufficient to warrant consideration of a re-opening and review of a PBR plan. The Commission also agrees with the CCA, EPCOR and AltaGas that an earned ROE that is 300 basis points above or below the approved ROE for two consecutive years would constitute sufficient evidence to warrant consideration of a re-opening and review of a PBR plan. Both of the gas distribution companies have indicated that weather normalized ROE should be used in the assessment of re-openers. The Commission considers that the fluctuations in earnings caused by variations from normal weather typically experienced by the gas distribution companies would not be an indication that the operation of a PBR plan needs reconsideration. Therefore, the Commission accepts the use of a weather normalized ROE, as proposed by the gas distribution companies, to eliminate the possibility that variations in weather might trigger a re-opener.

738. The Commission has considered whether the rate of return on equity to be used for the purposes of determining if a company's earnings exceed the +/-300 or +/-500 basis point thresholds should be the ROE included in the going-in rates or the approved generic ROE for the year(s) in which the need for a re-opener is to be considered. Consistent with the Commission's determinations in Decision 2009-035[939] and Decision 2010-146,[940] dealing with the ROE used for the purpose of the ENMAX earning sharing mechanism, the Commission will utilize the Generic Cost of Capital ROE which may be determined from time to time by the Commission, as the ROE from which to calculate the +/-300 or +/-500 basis point re-opener thresholds.

739. The actual ROE of the companies to be used to determine whether a re-opener is warranted, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

8.1.2 Change in service area

740. All of the companies, with the exception of Fortis, proposed that a material change to their service area or the number of customers to be served in their service area should result in a re-opening and review of their PBR plans. In this regard, EPCOR expressed concern with the potential for an unanticipated expansion in its service territory, while ATCO Electric, ATCO Gas and AltaGas were concerned with the potential for a material loss of customers.

741. Although a material change in service territory or number of customers may not signal that there is something wrong with the design or operation of a PBR plan, the Commission

[938] Exhibit 103.02, EPCOR application, page 79, paragraph 241.
[939] Decision 2009-035, paragraphs 418-419.
[940] Decision 2010-146, paragraphs 118-119.

agrees that such an event may warrant a re-opening and review of the affected company's PBR plan because the event may have a material impact on the company. The Commission considers that both a material contraction and expansion of customers or service territories may indicate that a re-opening and review of a PBR plan is required. With regard to the materiality thresholds proposed for the expansion or contraction of a company's service territory or customer base, the Commission considers that it is preferable to determine materiality on a case by case basis because materiality will vary from company to company and over time. However, in some cases a Z factor application may be sufficient, see Section 7.4.2.4.4.

8.1.3 Default supply obligations

742. ATCO Electric, ATCO Gas and AltaGas all identified, as events that would result in a re-opening and review of their respective plans, changes to the default supply regulation or a regulatory direction with respect to the assumption of default supply obligations in the case of ATCO Gas and ATCO Electric. The Commission has approved the creation of a Z factor in the PBR plans as more particularly set out in Section 7.2 of this decision. The Commission considers matters related to a change in law or a regulatory direction requiring a company to assume default supply obligations are best dealt with by way of an application for a Z factor adjustment, rather than as a re-opener. Nevertheless, if the event is such that it cannot be dealt with through a Z factor or other mechanism in the plan, an application for consideration of a re-opener could be filed.

8.1.4 Accounting standards

743. EPCOR proposed that material changes in accounting standards be included as an event that would signal the requirement for a re-opening and review of a PBR plan. Fortis[941] and AltaGas[942] identified material changes in accounting standards as a matter that should be addressed through a Y factor. The Commission agrees that material accounting changes may require an adjustment to rates under a PBR plan, but the impact of accounting changes should properly be considered in a Z factor application and do not necessarily signal that there is a problem with the design or operation of a PBR plan. Accordingly, the Commission finds that any rate adjustments required in response to material changes to accounting standards should be dealt with by way of a Z factor application.

8.1.5 Quality

744. IPPCA recommended that any material degradation in customer service should require a re-opening and review of a PBR plan. As well, EPCOR proposed that failure to meet service quality performance targets for two consecutive years should also require a re-opening and review of the company's PBR plan. These matters have been addressed in Section 14 of this decision in the Commission's findings regarding service quality.

8.1.6 Change of control

745. AltaGas proposed two events with respect to a change of ownership or control that would warrant a re-opening and review of its PBR plan leading, in its view, to an end to its PBR plan. These events are the sale of a controlling interest in AltaGas shares or the disposal of all or substantially all of its assets. The Commission considers that any change in controlling interest in AltaGas shares or the disposal of all or substantially all of the AltaGas assets is within the

[941] Exhibit 100.02, Fortis application, Section 6.1.2, paragraphs 92-94, pages 26-27.
[942] Exhibit 110.01, AltaGas application, Section 7.1.2, paragraph 82, page 24.

control of the AltaGas shareholder, the companies' parent business entities or the management of AltaGas. That is, the owners or management of AltaGas have a choice with respect to transactions of this nature. The Commission does not consider that the PBR plan should be terminable as a result of a voluntary event of this nature. Further, it is expected that any new share or asset purchaser would, as part of its due diligence, be aware of the PBR plan and would take that into consideration as part of its purchase decision. There is no obvious correlation between a change in the ownership structure of a company or the sale of its assets, and a design or operational failure of a PBR plan. In any event, for rate setting purposes, the assets of a company must be transferred at net book value and the same assets would continue to be used to provide utility service both before and after the share or asset transfer. Accordingly, the proposal to end the PBR plan in the event of a change of ownership or control is denied

8.1.7 Change in regulatory status

746. EPCOR proposed that a change in regulatory status should result in a re-opening of the PBR plan, leading to an end to the plan. It is not clear to the Commission why a change in regulatory status would indicate a failure of the operation of the PBR plan. In any event, any issues arising from a change in regulator would, in the Commission's view, be a matter for the regulator of jurisdiction to consider.

8.1.8 Change in taxable status

747. EPCOR also proposed that a change in the taxable status of the company should result in a re-opening of the company's PBR plan with a view to ending the plan. It is also unclear to the Commission why such a change in the taxable status of the company would require the abandonment of the entire PBR plan. In the Commission's view, a change in taxable status would be a matter for consideration pursuant to a Z factor application.

8.1.9 Spread between debt costs and the I factor

748. AltaGas proposed that a material change in the spread between the cost of debt and the I factor should warrant a re-opening of its PBR plan. The Commission understands that, generally, any material changes in the spread between the cost of debt and the I factor should be occasioned by changes in interest rates in the economy and would therefore be eventually reflected in the indexes that make up the I factor, as discussed in Section 7.4.2.6.1. Otherwise, any company-specific changes to debt costs that are not a result of changes to interest rates in the economy as a whole are the result of actions taken by management and should not be the subject of a re-opener. Accordingly, the Commission does not agree with AltaGas that a material change in the spread between the cost of debt and the I factor should be an event that occasions a re-opening of the PBR plan.

8.1.10 Cumulative impact of Z factors

749. AltaGas also proposed that the cumulative impact of Z factors may warrant a re-opening of a PBR plan. The Commission considers that each Z factor application must be considered on its own merits and, if warranted, rates will be adjusted accordingly. The fact that there may be many Z factors approved for a company under its PBR plan is not, in and of itself, an indication that the PBR plan should automatically be re-opened and reviewed.

8.1.11 Organizational structure changes

750. AltaGas also proposed that changes to a company's organizational structure should result in a re-opening of a PBR plan. However, the Commission considers that changes to the organizational structure of the company are within the control of the company or its shareholder and would not, in the Commission's view, signal the need for the PBR plan to be re-opened and reviewed.

8.1.12 Material misrepresentation

751. The CCA and the UCA proposed that a PBR plan should be re-opened and reviewed with a view to ending the plan in the face of a deliberate material misrepresentation by management. The Commission has not been persuaded that this circumstance would signal a failure of the PBR plan that cannot be remedied. Accordingly, the Commission considers that a re-opening and review of the plan may be warranted in this circumstance, but the Commission cannot conclude that such an event would warrant ending the plan. In any event, the Commission considers that, if faced with such a misrepresentation, there are other remedies available to the Commission through the plan itself as well as the imposition of an administrative penalty pursuant to Section 63 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2, which can be imposed to address such a serious matter.

8.1.13 Substantial change in circumstances

752. EPCOR proposed that a substantial change in circumstances should result in a re-opening and review of a PBR plan, leading in the company's view to an end to the plan. The Commission observes that a Z factor application is generally intended to consider a substantial change in circumstances. The Commission considers that, in the interests of regulatory efficiently and easing of the regulatory burden, the number of occasions for adjustments to rates by way of a Z factor or a re-opening and review of a PBR plan should be limited so as to allow the plans to generate the incentives that they are intended to create.

753. Nonetheless, the Commission recognizes that it is not possible to predict every circumstance that might legitimately be the subject of a re-opening and review of a PBR plan. Accordingly, should a substantial change in circumstances occur that does not, in the applicant's view, qualify for a Z factor application (as defined in Section 7.2 this decision) then an applicant may bring a re-opener application before the Commission for consideration. In this regard, the Commission is cognizant that, given a material event that is completely unforeseen and cannot be accommodated within the parameters of the PBR plan, it would be incumbent upon the Commission to re-open and review the plan.

8.2 Implementation

754. Several parties proposed that a re-opening of the PBR plan should be automatic following any of the events designated by the Commission as warranting a re-opening and review of a plan.

755. Calgary argued that "the design for re-openers contemplates a formulaic approach, once the utility is able to conclusively demonstrate that the achieved ROE is 300 basis points or more below the approved ROE, then the re-opener would be triggered automatically and parties would

begin discussions regarding potential changes to the existing PBR plan (either one-time or prospective or ongoing)."[943]

756. ATCO Electric and ATCO Gas stated that a re-opener should be automatic, once a triggering event is identified. Moreover, they suggested that, because the company is in the best position to be aware of an event that would signal the need for a re-opening of the PBR plan, it is the company that should notify the Commission that a re-opener of the PBR plan had been triggered.[944] Likewise, Fortis also proposed the automatic triggering of a re-opener if the upper or lower bounds of the earnings sharing mechanism it had proposed were exceeded.[945]

Commission findings

757. The Commission does not consider that a re-opening of the PBR plans should be automatic. As with any other matter before the Commission, any re-opening of a PBR plan must be on application to the Commission and the onus is on the applicant to demonstrate that a re-opening is warranted.

758. As noted above, the Commission finds that any party, including the Commission on its own motion, should be permitted to bring an application to re-open and review a PBR plan if there is sufficient evidence that there is a problem that cannot be resolved without re-opening and reviewing the plan. The Commission will consider applications to re-open and review a PBR plan and make a determination on the merits of the application as to whether a re-opening of the plan is warranted. In order to ensure fairness to all parties, parties are directed to notify the Commission of all events that they consider signal the need for a re-opener as soon as possible after they have been identified. The Commission also directs that the financial impact of any such event be captured in a separate account pending a ruling from the Commission. Any proposed financial impact is to be measured from the time the event occurred. The disposition of the balance in that account (positive or negative) would follow the Commission's ruling.[946]

9 Efficiency carry-over mechanism

9.1 Purpose and rationale for an efficiency carry-over mechanism

759. A company's incentive to find efficiencies weakens as the end of the PBR term approaches, because there is less time remaining for the company to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the company to continue to benefit from any efficiency gains after the end of the PBR term.

760. The CCA described an ECM as "a ratemaking mechanism designed to strengthen incentives for cost containment in the later years of a PBR period by permitting the utility to carry over some of the benefits of efficiency gains achieved in one PBR plan to the subsequent plan."[947] EPCOR, ATCO Gas and ATCO Electric proposed an ECM as part of their PBR plans.

943 Exhibit 629.01, Calgary argument, page 53.
944 Exhibit 631.01, ATCO Electric argument, paragraph 262 and Exhibit 632.01, ATCO Gas argument, paragraph 286.
945 Exhibit 633.01, Fortis argument at paragraph 226 citing the evidence of Lorimer at Transcript, Volume 11, page 2173.
946 Decision 2009-035, ENMAX FBR contains a similar provision in paragraph 257.
947 Exhibit 636.01, CCA argument, paragraph 344.

To support the inclusion of an ECM, ATCO Electric and ATCO Gas explained that "…the incentive for identifying and implementing efficiency measures is strongest in the earlier years of the PBR Plan as the utility will then have several years in which to take advantage of the efficiency improvements."[948] EPCOR's witness Dr. Weisman explained that "[t]he regulated firm will have less than ideal incentives to innovate and discover efficiencies if it believes that the regulator will simply claw back these efficiency gains at the end of the PBR regime and pass them on to consumers in the form of lower rates. These adverse incentives are particularly pronounced toward the end of the PBR regime."[949] AltaGas stated it "recognizes the purpose of such a mechanism is to maintain incentives for investment in efficiency initiatives throughout the IR [incentive regulation] term, particularly where the benefits are not expected to be recovered during that term."[950]

9.1.1 ATCO Electric's capital efficiency carry-over mechanism

761. ATCO Electric proposed two forms of efficiency carry-over mechanisms, one based on rate of return and one for capital. ATCO Electric's K factor efficiency incentive mechanism (KFEI) was also initially requested by ATCO Gas,[951] but ATCO Gas subsequently withdrew its request for a KFEI mechanism in its updated filing.[952]

762. ATCO Electric's KFEI is calculated as any positive difference between the forecast cost of a capital project qualifying for a K factor (discussed in Section 7.3.3.2) and the actual cost of the capital project at the end of the term. Under its proposal, ATCO Electric would carry forward one-half of this positive difference into the first year following the end of the PBR term and one-third of the difference into the second year following the end of the PBR term.[953] The proposed KFEI is intended to ensure that the company has an incentive to look for efficiencies in its K factor capital programs over the course of the entire PBR term.[954]

763. The UCA did not support ATCO Electric's request for a KFEI "[a]s the UCA is not supporting the inclusion of any Capital adjustments outside specific Capital Trackers."[955]

Commission findings

764. The Commission considers that the KFEI proposed by ATCO Electric does not promote additional efficiency. The Commission finds that the structure of ATCO Electric's KFEI would provide an incentive for the company to over forecast its capital programs. When its actual costs are subsequently less than the over-forecast amount, the company would benefit, but not necessarily as a result of efficiency gains. For this reason, ATCO Electric's KFEI is denied.

9.1.2 Return on equity (ROE) efficiency carry-over mechanisms

765. EPCOR, ATCO Gas and ATCO Electric proposed ECMs based on ROE as part of their PBR plans. EPCOR explained that its ECM would be balanced. This means that it would carry

[948] Exhibit 98.02, ATCO Electric application, page 11-1, paragraph 236, Exhibit 99.01, ATCO Gas application, page 43, paragraph 127.
[949] Exhibit 103.03, written evidence of Dr. Weisman, paragraph 60.
[950] Exhibit 628.01, AltaGas argument, page 74.
[951] Exhibit 99.01, ATCO Gas application, Section 2.10.1, paragraph 128, page 44.
[952] Exhibit 389.01, ATCO Gas updated filing, Section 2.8, paragraph 20, page 10.
[953] Exhibit 98.02, ATCO Electric application, Section 11, paragraph 237, page 11-1.
[954] Transcript, Volume 7, page 1280, Ms. Wilson.
[955] Exhibit 634.01, UCA argument, paragraph 352.

over half of any earnings above its approved ROE for a period of two years following the end of the PBR term. It would also receive 100 per cent of any shortfall below the approved ROE for a period of two years following the end of the PBR term.[956] EPCOR also linked the size of its rate of return adjustment to its service quality measures, with lower service quality leading to a lower percentage adjustment.[957] EPCOR did not indicate whether there was a limit on the amount of the earnings or losses to be carried over.

766. In contrast to EPCOR's ROE ECM, the ATCO companies did not include an adjustment for earnings deficiencies in their ECM proposals and did not link their ECM to service quality measures. ATCO Electric and ATCO Gas described their proposed ROE ECM as follows:

> a post PBR add-on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The "ROE bonus" would apply for 2 years after the end of the PBR Plan.[958]

767. Some parties noted that it does not appear that ECMs are common in North America. Very few examples of existing ECMs were cited or discussed in the hearing.[959] NERA indicated that ECMs are uncommon in PBR plans and stated that ECMs appear to be a desire to have the profit incentives of a PBR plan transcend to some degree beyond the end of the PBR term, "when rates would otherwise be squared with costs and profitable innovations capitalized for ratepayers."[960] Dr. Makholm suggested that in order to strengthen incentives, the term should be extended rather than including an ECM in a PBR plan.[961] NERA indicated that it has not seen evidence that adopting ECMs, as a partial lengthening of regulatory lag, "is worth the additional complications it would pose for the periodic future base rate cases."[962]

768. Some of the companies argued that ECMs provide a strengthening of incentives that outweigh any of the shortcomings of ECMs identified by NERA.[963] In addition, Dr. Lowry, the CCA and the ATCO companies submitted that an ECM is a deterrent to the gaming that might be associated with the timing of capital investments.[964]

769. Interveners, with the exception of Calgary, supported the general concept of ECMs, but they did not support the specific ECMs proposed by EPCOR and the ATCO companies.[965] The

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[956] Exhibit 630.02, EPCOR argument paragraph 264.
[957] Exhibit 103.02, EPCOR application, paragraph 46 and Exhibit 630.02, EPCOR argument, paragraph 265.
[958] Exhibit 98.02, ATCO Electric application, page 11-2, paragraph 238 and Exhibit 99.01, ATCO Gas application, page 44, paragraph 129.
[959] Exhibit 391.02, NERA second report, paragraph 65. In its survey of PBR plans, NERA identified two that had an ECM. Exhibit 199.02, Cal-ATCO Gas I-32 identified one plan.
[960] Exhibit 391.02, NERA second report, page 9, paragraph 13.
[961] Transcript, Volume 1, Dr. Makholm's evidence, pages 194 and 195.
[962] Exhibit 391.02, NERA second report, paragraph 13.
[963] Exhibit 630.02, EPCOR argument, paragraph 270; Exhibit 631.01, ATCO Electric argument, paragraph 281; Exhibit 632.01, ATCO Gas argument, paragraph 303.
[964] Transcript, Volume 13, Dr. Lowry, page 2642; Exhibit 631.01, ATCO Electric argument, page 70; Exhibit 648.02, ATCO Gas argument, page 131, paragraph 480; Exhibit 636.01, CCA argument, paragraphs 342-347.
[965] Exhibit 634.01, UCA argument, paragraphs 356 to 359; Exhibit 642.01, IPCAA reply, paragraph 21. IPCAA states that it concurs with the UCA argument for ECMs and Exhibit 636.01, CCA argument, paragraph 342.

UCA argued that ATCO Gas and ATCO Electric have achieved ROEs prior to PBR that are in excess of approved levels. Therefore, the UCA recommended that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period because this level of ROE "represents the current level of efficiency."[966] The UCA stated, "[b]y basing the target on the actual achievement, the intent of the PBR to incent greater efficiency is maintained. If a lower target is used, the incentive to improve efficiency is lessened."[967]

770. While supporting the concept of an ECM based on actual ROE performance, the UCA also suggested that there must be recognition of any efficiency gains achieved prior to the commencement of PBR that are not reflected in the going-in rates. The UCA stated, "[s]ince there are identified efficiency gains coming out of the COS environment, there should be an ECM for both going-in-rates and for the end of term."[968] The UCA proposed addressing the going-in portion of its proposed ECM through an adjustment to going-in rates. If no efficiency gains are recognized in going-in rates, the UCA argued that there should be no ECM included in the PBR plans.[969]

771. The CCA stated that it supports a Commission directed "generic ECM module, preferably by negotiation, in the early part of the PBR term."[970] The CCA also stated that the record was insufficient to approve an alternative ECM.[971]

772. Calgary also rejected the inclusion of an ROE ECM in ATCO Gas' PBR plan, providing among its reasons that there is no evidence that lengthening the period for recovery guarantees incentives or results in improved efficiencies, that there is no guarantee that efficiencies are passed on to ratepayers and that an ECM only spreads the incentives over a longer period but does not strengthen the incentives.[972]

773. Dr. Weisman discussed that alternatively an open-ended term operates as an efficiency carry-over mechanism because rates are not reset.[973] AltaGas stated that "its proposal to include an option to extend the term of its IR [incentive regulation] Plan may be considered a form of ECM, as it potentially allows AUI to continue operating under the approved IR [incentive regulation] Plan for an additional two years."[974]

Commission findings

774. In Decision 2009-035, the Commission recognized "that the longer the term of an FBR plan, the stronger the incentives for utilities to improve their efficiency."[975] In recognition of this issue the Commission stated in its February 26, 2010 letter initiating the PBR initiative that:

> The Commission will initiate a proceeding during the first PBR term to consider how the success of the PBR plan should be judged and how it might be re-initiated, or rates re-

966 Exhibit 634.01. UCA argument, paragraph 359.
967 Exhibit 634.01, UCA argument, paragraph 357.
968 Exhibit 634.01, UCA argument, paragraph 346.
969 Exhibit 634.01, UCA argument, paragraph 360.
970 Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.
971 Exhibit 636.01, CCA argument, page 120 of 152, paragraph 343.
972 Exhibit 629.01, Calgary argument, pages 61 to 62.
973 Transcript, Volume 10, Dr. Weisman, page 1827, lines 2 to 5.
974 Exhibit 628.01, AltaGas argument, page 74.
975 Decision 2009-035, paragraph 116.

based, at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives

775. The Commission agrees that ECMs are an innovative mechanism that will allow for a strengthening of incentives in the later years of the PBR term and may discourage gaming regarding the timing of capital projects. The Commission finds that the incentive properties of an ECM encourage companies to continue to make cost saving investments near the end of the PBR term.[976] The Commission agrees with ATCO's proposal for an upper limit for earnings that can be carried over and finds the limit of 0.5 per cent to be reasonable. Accordingly, the Commission approves the ATCO companies' ROE ECM for inclusion in the ATCO companies' PBR plans. If any of the other companies wish to submit the same ECM in their PBR plans, they may do so in their compliance filings.

776. EPCOR's proposed ECM includes adjustments for both over- and under-earnings in the two years following the end of the PBR term. The UCA did not support EPCOR's ECM because it compensates for under-earning which would dampen incentives and shield the utility from the full impact of its decisions.[977] The Commission agrees. As discussed above, the Commission supports a 0.5 per cent limit to the amount of earnings which may be carried over. Accordingly, the Commission finds that EPCOR's ECM should not include an adjustment for under-earning and should limit the amount of earnings which can be carried over to a maximum of 0.5 per cent.

777. With respect to EPCOR's proposal to include service quality as part of its ECM, the Commission will be relying on AUC Rule 002 along with administrative penalties under Section 63 of the *Alberta Utilities Commission Act* to ensure that service quality is maintained. In Section 14, the Commission has determined that these measures are sufficient to address service quality. Accordingly, EPCOR's proposed service quality adjustments to its ECM formula are not required.

778. The Commission rejects the UCA's recommendation that the average of the actual ROE for the 2009 to 2012 period be used as the basis for the ECMs rather than the approved ROE for the PBR plan period. The Commission has already made its determinations on the 2012 going-in rates in Section 3 of this decision. The purpose of the ECM is to provide an incentive to the companies to continue to achieve efficiencies in the latter part of the PBR term. If the Commission were to adopt the UCA's proposal, this incentive would be distorted because it would require the assessment of the efficiencies gained during the PBR term against financial results from the past and under a different regulatory framework.

779. In the Commission's view, the correct ROE to use for the purposes of calculating the amount of the ECM is the average approved generic ROE in place for each year during the PBR term.

[976] Exhibit 636.01, CCA argument, paragraph 344; Transcript, Volume 13, pages 2647-2648; Exhibit 103.03, evidence of Dr. Weisman, paragraphs 59 and 60; Transcript Volume 10, page 1820; Exhibit 628.01, AltaGas argument, page 74; Exhibit 647.01, ATCO Electric reply argument, page 70, paragraph 281; Exhibit 648.02, ATCO Gas reply argument, page 95, paragraph 303; Exhibit 630.02, EPCOR argument, paragraph 270.

[977] Exhibit 634.01, UCA argument, paragraphs 358-359.

780. The actual ROE of the companies to be used for the purposes of calculating the amount of the ECM, will be the calculated in the same way as the ROE reported in the companies' annual AUC Rule 005 filings.

9.1.3 Authority to approve an ECM

781. In its argument, Calgary questioned whether ECMs comply with the statutory framework in Alberta and raised issues of jurisdiction. Calgary stated that the equitable allocation or sharing with customers of benefits from incentives to be approved by the Commission is a matter of jurisdiction. Calgary argued that the Commission does not have jurisdiction to approve ATCO Gas' ECM as it is not a sharing of benefits from incentives and it is contrary to law. Calgary referenced AUC PBR Principle 5,[978] Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*, RSA 2000, c. G-5, in support of the equitable sharing of benefits derived from utility incentives being required for ESMs (earnings sharing mechanism) and ECMs (efficiency carry-over mechanism).[979] Calgary also argued that ATCO Gas' ECM will operate outside of the five-year PBR plan term. Calgary stated:

> There is no rate base determined for such post PBR term as part of this Proceeding, and as a result, the Commission's approval of ATCO's ECM will be contrary to Section 37 (1) of the GUA, which requires the Commission to determine the rate base of the gas utility and fix a fair return on that rate base at the same time. Since the rate base to which the ECM would apply will be determined at the ti[m]e of rebasing, there is obviously a time disconnect between setting ROE elements today (in this Proceeding) and determining the rate base in the future to which the ECM would apply.[980]

782. Section 45(1) of the *Gas Utilities Act* states:

> 45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Commission, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,
>
> (a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or
>
> (b) that are otherwise in the public interest.

783. Section 120(2)(d) of the *Electric Utilities Act* reads:

> 120(2) A tariff may provide
> ….
> (d) for incentives for efficiencies that result in cost savings or other benefits that can be shared in an equitable manner between the owner of the electric utility and customers.

784. ATCO Gas responded to Calgary's questioning of whether ECMs comply with the statutory framework in Alberta. ATCO Gas stated that its ROE ECM is a sharing of benefits

978 Bulletin 2010-20, page 3, Principle 5: "Customers and the regulated companies should share the benefits of a PBR plan."
979 Exhibit 629.01, Calgary argument, pages 56 and 62.
980 Exhibit 629.01, Calgary argument, page 62.

from incentives of 50 per cent of the difference between the average ROE and the approved ROE over the plan term, if the difference is positive.[981] Section 45(1)(a) of the *Gas Utilities Act* does not indicate when the intended cost savings or other benefits are to be allocated to customers. This section only addresses that cost savings or other benefits are intended to result in cost savings or other benefits to be allocated between the owner of a gas utility and its customers.[982] ATCO Gas pointed out that this is also the case for Section 120(2)(d) of the *Electric Utilities Act*[983] and both of these sections do not indicate that benefits have to be shared equally. Additionally, the Commission has been determining the fair rate of return for Alberta gas and electric utilities distinctly from determining rate base since Decision 2004-052,[984] which established a generic formula for the establishment of ROE. ATCO Gas argued that Section 37(1) has not been an issue since Decision 2004-052, and it will not be an issue under PBR.

785. With respect to the approval of its ROE ECM, ATCO Gas stated that the ROE ECM establishes the way in which a potential increase to a future ROE will be calculated. It does not establish the ROE for the utility. There is no inconsistency for the ROE ECM as the application of the effect of the ROE ECM will occur at the same time as the future ROE will be applied.[985]

Commission findings

786. Upon review of the legislation as well as the arguments of Calgary and ATCO Gas, the Commission finds that Section 45(1)(a) of the *Gas Utilities Act* and Section 120(2)(d) of the *Electric Utilities Act* allow for the approval of rates and tariffs that result in cost savings and other benefits to be allocated between utilities and their customers. Further, Section 5(h) of the *Electric Utilities Act* states that one of the purposes of the Act is “to provide for a framework so that the Alberta electric industry can, where necessary, be effectively regulated in a manner that minimizes the cost of regulation and provides incentives for efficiency.” Section 102(2)(d) of the *Electric Utilities Act* specifically refers to incentives for efficiencies and allows the Commission to include incentives for efficiencies that result in cost savings or other benefits, which is consistent with PBR. In addition, Section 121(3) of the *Electric Utilities Act* provides that “[a] tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives.”

787. By Order of the Lieutenant Governor in Council, the Commission has the authority under Section 45(1) of the *Gas Utilities Act* “to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act.”[986]

788. ATCO Gas has correctly indicated that its ROE ECM would result in a sharing of any differences between its average ROE over the plan term and approved ROE, in the case where the average ROE over the term is higher than the approved ROE. Any benefits of a higher ROE

981 Exhibit 648.02, ATCO Gas reply argument, page 131 of 152, paragraph 482.
982 Exhibit 648.02, ATCO Gas reply argument, page 123 of 152, paragraph 455.
983 Exhibit 648.02, ATCO Gas reply argument, page 124 of 152, paragraph 456.
984 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), Nova Gas Transmission Ltd., Application No. 1271597, July 2, 2004.
985 Exhibit 648.02, ATCO Gas reply argument, page 132 of 152, paragraph 483.
986 O.C. 235/2011 June 1, 2011.

would be shared with customers under ATCO Gas' ECM proposal. Further, the entire rationale for an ECM is to incent the company to pursue additional cost savings particularly through capital investment that it might not be otherwise inclined to do in the latter part of the PBR term. Customers will directly benefit from these additional cost savings when utility costs and revenues are next reviewed and rates are adjusted.

789. The Commission has considered the ECMs proposed by the companies in light of the legislative requirements under the *Electric Utilities Act* and the *Gas Utilities Act*. The ECMs as approved above provide for incentives for efficiencies, or are intended to result in cost savings or other benefits to be allocated between the owner of the utility and its customers.

790. Calgary argued Section 37(1) of the *Gas Utilities Act* requires that rate base and rate of return be approved at the same time. Section 37(1) stated that the Commission shall determine a rate base and "upon determining a rate base it shall fix a fair return on the rate base." Section 45(1) of the *Gas Utilities Act* states that instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44 of the Act, the Commission may approve rates that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers. This includes the jurisdiction to approve the provisions of an incentive plan that are intended to create incentives during the PBR term to achieve cost savings or other benefits to be allocated between the owner of the gas utility and its customers in a period beyond the initial plan term.

791. The Commission concludes that ECMs are consistent with the governing legislation and it is within the Commission's jurisdiction to consider ECMs as part of the PBR plan under Section 45(1) of the *Gas Utilities Act* and under sections 5(h), 120(2)(d) and 121(3) of the *Electric Utilities Act*.

10 Earnings sharing mechanism

792. An ESM (earnings sharing mechanism) is intended to address the potential that a regulated company will earn a return significantly above or below the approved ROE (return on equity) during the PBR term. An ESM generally establishes a formula for sharing with the company's customers earnings in excess of a designated amount and may provide for a sharing of any shortfall below a designated amount. The implementation of an ESM generally requires annual filings of ROE results and sharing calculations and some form of verification of these filings. An ESM is a common feature of first generation PBR plans.

793. The Commission approved an ESM in Decision 2009-035 as part of ENMAX's FBR plan. ENMAX's approved ESM provides for an annual sharing mechanism equal to 50 per cent of ENMAX's earnings that are over 100 basis points above the approved ROE established by the Commission. Sharing of these earnings is given effect by way of a reduction in rates in the year following the year in which the excess earnings were realized. The ENMAX ESM provides for a sharing of earnings above the approved ROE but not for a sharing of any earning below the approved ROE.

794. In approving the ESM for ENMAX, the Commission acknowledged that an ESM blunts efficiency incentives but recognized that performance-based regulation was a relatively new

development in Alberta utility regulation and considered that, in the circumstances, it provided a useful safeguard in the early stages of a PBR plan.[987]

795. Fortis and the ATCO companies proposed including an ESM in their PBR plans. Additionally, the UCA, the CCA and Calgary supported the inclusion of ESMs in the companies' PBR plans.

796. Fortis proposed a symmetrical deadband range of 100 basis points above and below the approved ROE. Any return within 100 basis points of the approved ROE would not be shared with customers, and any shortfall up to 100 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. However, any return above the 100 basis point threshold would be shared equally with customers by way of a rate reduction in the following year, while any shortfall below the 100 basis point threshold would be shared equally with customers by way of a rate increase in the following year. Under the Fortis proposal, the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE in one year.[988]

797. Fortis stated that "given that this is the first time that FortisAlberta is applying for a PBR plan, an ESM will serve as a safeguard to buffer the earnings results during PBR implementation, in a manner beneficial to both customers and the Company."[989]

798. When asked by the Commission how its PBR proposal would need to change if its ESM were eliminated, Fortis stated:

> FortisAlberta's PBR Proposal would not otherwise change if the ESM component were eliminated. The proposed re-opener mechanism is based on the actual ROE before the ESM is applied.[990]

799. ATCO Electric and ATCO Gas proposed an ESM in each of their plans similar to the Fortis proposal. However, the ATCO companies proposed a symmetrical deadband range of 200 basis points above and below the approved ROE. Any return within 200 basis points of the approved ROE would not be shared with customers, and any shortfall up to 200 basis points below the approved ROE would not be recovered through a subsequent rate adjustment. Actual results beyond the 200 basis point threshold would be shared equally with customers by way of a rate reduction or rate increase in the following year, as required.

800. Under the ATCO companies' proposals,[991] the PBR plan would be re-opened and reviewed if the achieved ROE is more than 300 basis points above or below the approved ROE, after accounting for the implementation of the ESM. Ms. Wilson for the ATCO companies described the relationship between the companies' ESM and the re-opener proposal as follows, "[g]enerally earnings-sharing mechanisms and reopener clauses are viewed more as ensuring that if some of the parameters in the plan haven't been completely specified correctly or if something unexpected comes out of the PBR plan that was not -- the plan somehow doesn't have the ability

[987] Decision 2009-035, paragraphs 280 and 281.
[988] Exhibit 100.02, Fortis application, paragraph 126.
[989] Exhibit 100.02, Fortis application, page 35, paragraph 121.
[990] Exhibit 219.02, Fortis, AUC-ALLUTILITIES-FAI-16.
[991] Exhibit 98.02, ATCO Electric application, paragraph 233; Exhibit 99.01, ATCO Gas application, paragraph 123.

to address, those mechanisms ensure that the plan will not result in extreme outcomes for either customers or the utility."[992]

801. In addition to the above, ATCO Gas added the following caveat regarding its ESM and weather deferral account:

> In the event that ATCO Gas no longer has a Weather Deferral Account (WDA) during the course of the PBR Plan, the ROE to be used [for earnings sharing] will be the actual utility ROE, including the effects of deviations from normal weather.[993]

802. ATCO Electric and ATCO Gas submitted in argument that their ESMs have sufficiently wide deadbands to address any blunting of efficiency incentives that an ESM might cause.[994] The ATCO companies did not propose any changes to their PBR plans if ESMs were not approved. Specifically, the ATCO companies indicated that, if their plans were not to include an ESM, the 300 basis point threshold for re-openers would remain unchanged.[995]

803. Initially, AltaGas proposed an ESM as part of its PBR plan.[996] AltaGas proposed a symmetrical ESM with 50/50 sharing of earnings between 100 and 200 basis points above and below the approved ROE and 60(company)/40(customer) sharing of earnings over 200 basis points above and below the approved ROE.[997] AltaGas also submitted that, if achieved earnings are significantly greater than the approved ROE (i.e., above or below 300 basis points for two consecutive years or above or below 400 basis points in a single year), customers or AltaGas may apply for a re-opening of the PBR plan.[998]

804. AltaGas initially indicated that, if there was no ESM, three adjustments to the PBR formula would be required. First, the rates at the beginning of the PBR period would need to be adjusted upward. Second, the Y and Z factors might need to be carefully evaluated, and perhaps more broadly defined, given the potential effect of higher risks on the willingness of AltaGas to fund capital and commit resources. Third, AltaGas stated that "provided the rate of return reflects the impacts of higher financial risks, the Company faces stronger incentives to increase efficiency, without a provision for earnings sharing. Under these circumstances, it would be appropriate to consider a stretch component to the X Factor."[999] During the hearing, AltaGas confirmed that it is prepared to dispense with an ESM in its PBR plan with the addition of a stretch factor of between 0.1 and 0.2 per cent.[1000]

805. EPCOR did not propose an ESM as part of its PBR plan. EPCOR argued that ESMs are not consistent with AUC PBR principles 1, 3, and 5.[1001] As part of its application, EPCOR stated that a pure price cap approach has several advantages over a price cap plan with an ESM,

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[992] Transcript. Volume 3, page 568, Ms. Wilson.
[993] Exhibit 99.01, ATCO Gas application, page 41, paragraph 118.
[994] Exhibit 631.01, ATCO Electric argument, paragraph 267 and Exhibit 632.01, ATCO Gas argument, paragraph 292; Dr. Carpenter, Transcript, Volume 7, page 1308, lines17 to 22.
[995] Exhibit 631.01, ATCO Electric argument, paragraph 269 and Exhibit 632.01, ATCO Gas argument, paragraph 294.
[996] Exhibit 110.01, AltaGas application, paragraph 89.
[997] Exhibit 110.01, AltaGas application, paragraph 89.
[998] Exhibit 628.01, AltaGas argument, page 67.
[999] Exhibit 247.01, AltaGas, AUC-ALLUTILITIES-AUI-16.
[1000] Exhibit 529.01, AltaGas letter on corrections and amendments to its incentive regulation application, 2012-04-18, page 4.
[1001] Exhibit 630.02, EPCOR argument, paragraph 238.

because a pure price cap plan provides for greater incentives for efficiency that are more aligned with those in a competitive market.[1002]

806. EPCOR pointed to Dr. Weisman's evidence, stating that the gains from a pure price cap plan should exceed those from a PBR plan with earnings sharing. A plan without an ESM would also largely eliminate concerns with respect to gaming. Dr. Weisman stated:

> First, consumers bear less risk under pure price cap regulation that under a PBR with earnings sharing because prices do not vary directly with either the costs or the earnings of the regulated firm. Second, at least as a theoretical matter, because the incentives for cost reducing innovation are more pronounced under pure price cap regulation, the X factor should be higher than under a PBR regime that incorporates earnings sharing, *ceteris paribus*. Third, the incentives for strategic cost shifting, cost misreporting and abuse are mitigated under a pure price cap regime and this further lessens consumer exposure to prices that may reflect higher costs associated with such inefficiencies. As a corollary to this third observation, the pure PBR framework obviates the need for regulatory intervention with respect to cost allocations under a shared services model as rates are invariant to changes in such allocations over the course of the PBR regime. Finally, as the ongoing administration of a pure price regime economizes on both Commission and company resources, consumers benefit from the flow through of such efficiencies in the form of lower prices over time.[1003]

807. When questioned by the Commission about how its PBR plan would change if an ESM were adopted, EPCOR stated:

> At a minimum, if an earnings sharing mechanism were added to EDTI's PBR Plan, EDTI's proposed stretch factor would need to be eliminated, EDTI's proposed X factor would need to be reduced (i.e., made more negative) and the proposed timeline for the annual rate adjustment process would need to be adjusted due to the significant regulatory burden that earnings sharing mechanisms entail.[1004]

808. Dr. Schoech for AltaGas argued that the determination of earnings to be shared would result in a situation akin to cost of service regulation. Dr. Schoech stated:

> The earnings-sharing formulas introduce a bit of cost of service – I emphasize a bit of cost of service back into the regulation because earnings sharings looks [sic.] at the actual rates of return that the company achieves which, in turn, are based upon the company's costs. A pure revenue per customer cap with no earnings sharing completely decouples rates from the utility costs. And it's the disincentive or the reduced incentives, I guess I should say, arise from that reintroduction of an element of cost of service.[1005]

809. The interveners generally supported ESMs as part of PBR plans. The UCA indicated that its proposed menu approach for the X factor, which has been described in Section 6.2, has an ESM embedded into the menu options. However, if the menu approach is not adopted for the X factor, the UCA supported adoption of the ESM approved for ENMAX,[1006] including

1002 Exhibit 103.02, EPCOR application, paragraph 16.
1003 Exhibit 103.03, EPCOR application, Appendix A: The EDTI PBR Framework: Commission Principles and Economic Foundations, paragraph 78.
1004 Exhibit 233.01, EPCOR, AUC-ALLUTILITIES-EDTI-16, page 49.
1005 Transcript, Volume 8, page 1376, lines 6 to 15.
1006 Exhibit 634.02, UCA argument, paragraphs 329 and 330.

independent verification of the ROE with attestation by an officer of the company, with the same filing requirements as established for ENMAX.[1007]

810. The CCA also recommended that the PBR plans include ESMs similar to ENMAX's asymmetrical ESM[1008] and that a corporate sign-off be required on any data relied upon for the calculation of the earnings to be shared.[1009]

811. Calgary recommended adoption of an ESM for ATCO Gas but proposed that it be asymmetrical, providing for a sharing only of earnings above the approved ROE. Calgary questioned whether an ESM with a deadband is genuinely a sharing with ratepayers that would meet AUC Principle 5 and the legislative requirements of the *Electric Utilities Act*. Calgary argued that the equitable sharing or allocation of benefits derived from utility incentives with customers is required under Section 120(2)(d) of the *Electric Utilities Act* and Section 45(1)(a) of the *Gas Utilities Act*.[1010]

812. ENMAX did not take a position on the inclusion of ESMs in the proposed PBR plans of the companies, other than to state that an ESM should be symmetrical. However, ENMAX commented on the operation of the ESM in its FBR plan. In its evidence, ENMAX stated that although the ENMAX ESM has benefited customers, it has not benefited the company due to the unexpectedly high costs to establish, review and independently verify its ESM calculations. This verification process resulted in additional filing requirements over and above the requirements under AUC Rule 005.

813. Parties also pointed to concerns with gaming in ascertaining the actual returns to be shared.[1011] ENMAX proposed that, if the Commission approves an ESM for the companies, the Commission should determine in advance the necessary information required to ensure customers are receiving their share of the benefits.[1012] In this regard, most parties agreed that AUC Rule 005 would be the best vehicle to measure annual earnings sharing.[1013] ATCO Electric and ATCO Gas stated that the Commission's current safeguards in AUC Rule 005 are sufficient to address any concerns with administration and gaming.[1014]

814. Ms. Frayer, in her evidence for Fortis, noted that ESMs have other benefits to counter the weakening of incentives. These include the avoidance of unscheduled regulatory interventions, such as windfall profit taxes or other forms of claw-back, which distort patterns of investment and return.[1015]

815. IPCAA stated that an annual sharing of benefits would not be necessary as "[a]n annual benefit-sharing calculation based on net income would require a review of all revenues and costs, since net income is a comprehensive financial calculation. This in turn would require detailed variance analysis by management and extensive review, knowing that litigation is a possibility. It

[1007] Exhibit 634.02, UCA argument, paragraph 338.
[1008] Exhibit 636.01, CCA argument, paragraph 337.
[1009] Exhibit 636.01, CCA argument, paragraph 341.
[1010] Exhibit 629.01, Calgary argument, pages 55 and 56.
[1011] Exhibit 298.02, Calgary evidence, paragraph 165; Exhibit 630.02, EPCOR argument, paragraph 13,
[1012] Exhibit 297.01, EPCOR evidence, paragraphs 41 to 45.
[1013] Exhibit 100.02, Fortis application, page 35, paragraphs 122-123; Exhibit 98.02, ATCO Electric application, pages 9-1-9-2, paragraph 228; Exhibit 629.01, Calgary argument, page 59 of 72.
[1014] Exhibit 631.01, ATCO Electric argument, paragraph 272 and Exhibit 632.01, ATCO argument, paragraph 297.
[1015] Exhibit 100.02, Fortis application, Performance Based Regulation Evidence attachment, page 82, lines 17 to 21

thus appears that annual benefits sharing could perpetuate the regulatory burden."[1016] IPCAA made no specific recommendations with respect to the structure of earnings sharing except to state that "any sharing calculations should occur at the end of the PBR period rather than annually" and that the scope of review should be clearly defined in advance.[1017]

Commission findings

816. The Commission generally agrees with Dr. Weisman and Dr. Schoech that PBR plans with an ESM provide weaker incentives for efficiency gains, in part because costs and rates are no longer completely decoupled. The Commission notes Dr. Weisman's concerns with respect to ESMs.

> And when I say that earnings sharing has problems, it has problems I think on both sides. I don't think, as I mentioned in my rebuttal testimony, it brings forth the best behaviour on the part of regulators or the firms they regulate. I think that there are incentives for cost misreporting; cost shifting; the incentives are blunted with regard to managerial effort, and the reason for that is that the firm bears the entire costs of its effort at reducing costs but only retains a share of the fruits from those efforts.[1018]

817. The Commission agrees with EPCOR, AltaGas, ENMAX and IPCAA that increased scrutiny on an annual basis would be required for earnings sharing and would result in a greater regulatory burden. Accordingly, the Commission is concerned that including an ESM in the PBR plans of the companies would not be consistent with the objectives of Principle 3 to reduce the regulatory burden over time.

818. In the Commission's view, the safeguards offered by an ESM do not outweigh the negative efficiency incentives that would be re-introduced into the PBR plan as a result of the incorporation of an ESM.

819. The Commission has approved safeguards in Section 8 of this decision that provide for a re-opening and review of the companies' PBR plans if the reported ROE of a company significantly exceeds the approved ROE or if the company experiences a significant shortfall in earnings. These safeguards are comparable to those provided for by an ESM but do not, in the Commission's view, exhibit the disincentives that arise with ESMs. The Commission finds that the safeguards set out in Section 8 are adequate to protect both the companies and consumers.

820. In addition, the Commission notes that the companies' reported earnings will generally vary, sometimes significantly, from year to year during the PBR term. The effect of this variability in earnings coupled with an ESM was demonstrated by the operation of ENMAX's ESM for transmission and distribution:

> EPC's customers benefited from $0.331 million of earnings sharing for Transmission in 2008 and $0.563 million of earnings sharing for Distribution in 2009. As EPC is forecasting that it will earn below the AUC approved ROE for the remainder of the FBR term for both Distribution and Transmission, EPC expects that there will be no earnings sharing payments for the period 2011 to 2013.[1019]

1016 Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-26.
1017 Exhibit 306.01, IPCAA Vidya Knowledge Systems Corp. direct evidence, page 10, lines 23-29.
1018 Transcript, Volume 9, page 1765, Dr. Weisman.
1019 Exhibit 297.01, ENMAX evidence, paragraph 41.

821. The Commission finds that this volatility of earnings argues against the introduction of ESMs. This is because the company may have sufficient earnings in one year to trigger a sharing with customers and then experience earnings below the approved ROE in subsequent years but not sufficient to trigger a sharing of the shortfall with customers. This deprives the company of a reasonable opportunity to earn its approved ROE over the PBR term. Conversely, the company may have insufficient earnings in one year, triggering a sharing of the shortfall with customers and then experience earnings above the approved ROE in subsequent years but not sufficient to trigger sharing with customers. This results in customers paying rates higher than necessary to give the company a reasonable opportunity to earn its approved ROE over the PBR term.

822. Accordingly, the Commission finds that ESMs, as proposed by the parties, are not warranted as an additional safeguard and the disincentives they will introduce are inconsistent with the objectives of PBR.

11 Term

823. The PBR term establishes the period over which a company must operate under the parameters of the formula in the PBR plan.

824. All of the parties recognized that, in setting the term of a PBR plan, the Commission must achieve a balance between two competing interests, namely, ensuring that the term is long enough to permit the company to achieve and capture efficiencies but not so long that the company's revenues are substantially out of sync with costs. As NERA stated, "ultimately we base rates for North American ratepayers on cost, and while we want to -- while it is a praise-worthy pursuit to want to avoid a disruption of frequent base rate cases, it is hard over the course of years to base rates on cost if you don't once in a while look at the costs."[1020]

825. The Commission noted this relationship in Decision 2009-035, when it rejected ENMAX's application for a10-year term as too long and approved a seven-year term which, given the passage of time, resulted in a five-year operational FBR term.[1021]

826. Each of the distribution companies, with the exception of ATCO Electric, proposed a PBR plan with a five-year term. ATCO Electric proposed a term of four years; stating, among other reasons, that staggering the filing of a second generation PBR plan with other companies would ease the regulatory workload for both the company and the Commission.[1022] In addition, ATCO Electric,[1023] ATCO Gas[1024] and AltaGas[1025] also proposed an optional two-year extension to the term, exercisable at the companies' election. Fortis stated in argument that it was open to an extension if the plan was working well.[1026]

827. Some of the companies, in proposing the terms for their PBR plans, also requested some form of rebasing or adjustment for capital expenditures during the PBR term.[1027] The

1020 Transcript, Volume 1, page 197, lines 11-16.
1021 Decision 2009-035, paragraph 118.
1022 Exhibit 205.01, AUC-AE-13(a).
1023 Exhibit 632.01, ATCO Gas argument, page 9, paragraph 28.
1024 Exhibit 205.01, AUC-AE-13(b); Exhibit 0212.02, AUC-AG-3(a).
1025 Exhibit 110.01, AltaGas application, page 15, paragraph 54.
1026 Exhibit 633.01, Fortis argument, page 12, paragraphs 50 and 51.
1027 See Section 7.3.3.2.

Commission has addressed the treatment of capital expenditures and adjustments in Section 7.3 of this decision.

828. The CCA supported the companies' applied-for terms but stated that, if the Commission preferred a shorter term such as three or four years, the CCA would not be opposed. In its view, a shorter term could reduce or eliminate some of the requests for supplemental capital budgets with less concern about untoward safety or reliability consequences during the PBR term. Nonetheless, the CCA stated that, whatever term is determined by the Commission, the length of the plans should be consistent among all companies.[1028] With regard to the proposals from ATCO Electric, ATCO Gas, and AltaGas to include an extension option to their plans' term, the CCA stated that "extensions should be allowed only with the consent of most parties"[1029] and that, if the plan is viewed as a success by all parties, there could potentially be an extension for up to five years.[1030]

829. Calgary supported a term of five years[1031] for ATCO Gas and indicated that a five-year term coincides with the Commission's efficiency, fair return and simplicity principles.[1032] However, Calgary did not support a unilateral extension of the ATCO Gas five-year term proposal.[1033]

830. The UCA did not support pursuing PBR because it considered that the risks of implementation outweigh the benefits of doing so.[1034] However, accepting that the Commission may nonetheless move forward with PBR, the UCA recommended that, as a first generation plan, the Commission adopt a term of three years.[1035] A period of four years was proposed for the second generation. In both cases, the UCA also recommended the imposition of a mid-term assessment to examine the PBR plans to date and to structure the design of the next term.[1036] Dr. Cronin, on behalf of the UCA, also opposed term extensions.[1037]

831. IPCAA submitted that it is too early for the Commission to implement a full PBR plan, and limited its recommendation to what it considered would be a suitable term for its limited G&A PBR plan. IPCAA stated that its limited G&A PBR plan "could run for a two-year term so that a comprehensive plan could be initiated when the limited plan expires."[1038]

Commission findings

832. One of the purposes of PBR is to start with cost of service-based rates and then sever the link between revenues and costs as a means of strengthening incentives for the companies to seek productivity improvements, and achieve lower costs than would otherwise be realized under cost of service regulation. PBR regulation allows regulated prices to change without a review of the company's costs, thereby lengthening regulatory lag. This better exposes the companies to the types of incentives faced by competitive firms. However, periodic review of the plans will be

[1028] Exhibit 636.01, CCA argument, page 12, paragraph 33-38.
[1029] Exhibit 636.01, CCA argument, page 12, paragraph 35.
[1030] Exhibit 636.01, CCA argument, page 14-15, paragraphs 42-43.
[1031] Exhibit 298.02, Calgary evidence, page 29.
[1032] Exhibit 64.01, PBR Principles Bulletin 2010-20.
[1033] Exhibit 629.01, Calgary argument, PDF page 20.
[1034] Exhibit 634.01, UCA argument, paragraphs 28-53.
[1035] Exhibit 299.02, Cronin and Motluk UCA evidence page 14, lines 15-23.
[1036] Exhibit 634.01, UCA argument, page 12, paragraphs 68-71.
[1037] Transcript, Volume 17, page 3322, lines 1-17.
[1038] Exhibit 635.16, IPCAA argument, page 2, paragraphs 8-9.

required. What the correct timing of a review will be and what the nature of the review should be will depend on the circumstances at the time.

833. The length of a typical PBR term in North America is from three to five years after which there is typically a rebasing and a recalculation of rates.[1039]

834. During the proceeding, the Commission asked parties to explore options for establishing a term.[1040] One option which was considered was whether it was possible to implement an open-ended term where there is no fixed date for the end of the PBR plan. The utilities and interveners were asked whether or not they supported an open-ended term during the hearing.

835. While most parties agreed that an open-ended term would have a positive impact on incentives,[1041] they also considered this proposal to be problematic.[1042] No party supported such a proposal, particularly for a first generation PBR plan.[1043] Dr. Weisman, on behalf of EPCOR, stated, "I think you, more generally, see that [open-ended term] in second and third-generation plans than you do the initial ones."[1044] As well, NERA concluded that such a proposal would be impractical and in their experience, they had not seen such a proposal implemented by other North American regulators.[1045] The Commission agrees that an open-ended term for the first generation PBR plans is not warranted.

836. The Commission considers that a five-year fixed term for each of the PBR plans is reasonable. The Commission has chosen this period recognizing that some of the elements approved in the PBR plans in this decision are novel and this term is consistent with the typical term for PBR plans in North America. Although a shorter term tends to blunt the incentives for companies to identify and implement productivity improvements, the Commission has approved the inclusion of an efficiency carry-over mechanism to mitigate this effect.

837. The Commission does not approve the recommendation of the UCA for a mid-term review half-way through the PBR term because doing so effectively shortens the term to two years, thereby eliminating the benefits achieved from lengthening the regulatory lag.

838. In order to ensure that all utilities are treated consistently, the Commission rejects ATCO Electric's four-year term proposal and directs all companies to proceed with a five-year fixed term. The Commission denies the proposals of ATCO Gas, ATCO Electric and AltaGas for a unilateral option to extend their plan term.

839. The Commission will not make a determination at this stage as to how it will go forward following the end of the five-year term. As the Commission noted in its February 26, 2010 letter; "[t]he Commission will initiate a proceeding during the first PBR term to consider how the

[1039] Exhibit 100.02, LEI evidence, pages 31-32, PDF page 97; Exhibit 103.02, EPCOR application, page 19, paragraph 45; Exhibit 205.01, AUC-AE-13(a); Exhibit 391.02, NERA second report, Table 3, page 30 for a comprehensive list of PBR term lengths in Canada and the United States; Exhibit 629.01, Calgary argument, calculated the NERA example plan average as 4.9 years.

[1040] Exhibit 80.02, NERA first report, PDF page 8.

[1041] Dr. Carpenter, Transcript, Volume 5, page 832; Ms. Frayer, Transcript, Volume 11, pages 2188-2189.

[1042] Ms. Frayer, Transcript, Volume 11, pages 2188-2189.

[1043] Dr. Carpenter, Transcript, Volume 5, page 832; Dr. Makholm, NERA, Transcript, Volume 1, page 197; Exhibit 636.01, CCA argument, page 15, paragraph 42.

[1044] Transcript, Volume 10, page 1826.

[1045] Transcript, Volume 1, page 197 at lines 9 and 22.

success of the PBR plan should be judged and how it might be re-initiated, or rates 're-based,' at the end of the initial five-year term in a way that minimizes potential distortions to economic efficiency incentives."[1046]

12 Maximum investment levels

840. The customer and retailer terms and conditions of electric distribution service form part of the distribution tariffs of the electric distribution companies. Over the PBR term, it is expected that there may be changes required to these terms and conditions of service. Among the elements in the terms and conditions of service of the electric distribution companies which may change are the maximum investment levels (MILs) and the service fee schedule. MILs are the maximum amounts of money that an electric distribution company can invest in a new service for a customer. This investment level is added to the electric distribution company's rate base. The remaining cost of a new connection, if any, must be supplied by the customer as a contribution.

841. Recently, the electric distribution companies, with the participation of stakeholder groups, developed a common approach to managing changes to MILs. This common approach was approved for Fortis,[1047] ATCO Electric,[1048] and EPCOR.[1049]

842. Gas distribution companies do not have MILs but do have specified customer contribution levels. The specified customer contribution levels for ATCO Gas can be found in Schedule C to its terms and conditions of service. AltaGas also provides for specific customer contribution levels as part of its terms and conditions of service.

843. Each of the distribution companies proposed an automatic adjustment to their MILs/customer contribution levels during the term of the PBR. AltaGas proposed that its customer contribution levels be adjusted annually by the I-X mechanism. With the exception of the residential and street lighting customer groups, Fortis also proposed that its MILs be indexed annually by the I-X mechanism. For the residential and street lighting customer groups, Fortis proposed an increase of I-X plus10 per cent.[1050] EPCOR proposed that the MILs would be included in its annual capital forecast in its capital factor (K factor) stating that its MILs would be based on the historical actual costs, adjusted to keep pace with forecast construction costs.[1051] ATCO Electric proposed that its MILs be adjusted by the I factor only because it considered that the I-X mechanism would not offset the effect of the company's investment. Rather, AE argued that increasing MILs by the I factor ensures future customers receive equitable company investment and mitigates intergenerational equity issues.[1052] Similarly, ATCO Gas proposed that its specified customer contributions be adjusted only by the I factor. Both ATCO Electric and ATCO Gas submitted that changes to MILs or customer contribution policies could have a material impact on whether future capital expenditures can reasonably be expected to be covered

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1046 Exhibit 1.01.
1047 Decision 2010-309: FortisAlberta Inc., 2010-2011 Distribution Tariff – Phase I, Application No. 1605170, Proceeding ID No. 212, July 6, 2010.
1048 Decision 2011-134: ATCO Electric Ltd., 2011-2012 Phase I Distribution Tariff, Application No. 1606228, Proceeding ID No. 650, April 13, 2011.
1049 Decision 2010-505: EPCOR Distribution & Transmission Inc., 2010-2011 Phase I Distribution Tariff, Application No. 1605759; Proceeding ID No. 437, October 28, 2010.
1050 Exhibit 100.02, Fortis application, page 53, paragraph 187-188.
1051 Exhibit 238.01, UCA-EDTI-08 b).
1052 Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256.

by the I-X mechanism.[1053] Both utilities also argued that this proceeding is not the proper forum to address changes to MILs and customer contribution policies.

844. The UCA opposed ATCO Gas and ATCO Electric's proposals to adjust its specified customer contributions/MILs by I only and recommended that any adjustment be made by the I-X mechanism as, in its view, these costs should be subject to the same efficiency incentives as any other utility cost.[1054] Calgary also rejected ATCO Gas' proposal and recommended that ATCO Gas adjust its specified customer contributions by I-X. Neither the CCA nor IPCAA provided any specific comments or recommendations regarding customer contributions/MILs.

845. For ease of reference, a summary of the proposed treatment for adjusting MILs/customer contributions is provided in the table below:

Table 12-1 Summary of proposed maximum investment levels

Category	Fortis[1055]	ATCO Electric/Gas[1056 1057]	AltaGas[1058]	EPCOR[1059]	UCA[1060]	Calgary[1061]
Residential	I-X+10%	I	I-X	Part of K factor adjustments	I-X	I-X
Street lighting	I-X + 10%	I	I-X	Part of K factor adjustments	I-X	I-X
All other customers	I-X	I	I-X	Part of K factor adjustments	I-X	I-X

Commission findings

846. It is evident from the submissions that the electric distribution companies want to continue to manage changes to their MILs in accordance with the common approach that was reached among the companies and stakeholders. However, this common approach was developed and approved by the Commission under cost of service rate regulation.

847. The Commission has considered the submissions of ATCO Electric and ATCO Gas regarding changes to MILs or customer contribution policies and agrees that this is not the forum to determine such a policy. Customer contribution policy considerations will be addressed in a future generic proceeding as directed by the Commission.

848. However, with regard to providing for the automatic escalation of MILs and specific customer contributions during the PBR term, the Commission considers that these contributions should be escalated by I-X.

849. In Decision 2000-01,[1062] the Commission's predecessor, the Alberta Energy and Utilities Board stated "an appropriate contribution policy … provides a suitable balance to an unlimited

[1053] Exhibit 631.01, ATCO Electric argument, page 64, paragraph 256; Exhibit 648.02, ATCO Gas reply argument, page 149, paragraphs 540-543.
[1054] Exhibit 300.02, UCA evidence of Russ Bell at page 56, A52.
[1055] Exhibit 100.02, Fortis application, page 53, paragraph 188.
[1056] Exhibit 476.01, ATCO Electric rebuttal evidence, page 66, paragraphs 203-204.
[1057] Exhibit 632.01, ATCO Gas argument, page 87, paragraph 282.
[1058] Exhibit 628.01, AltaGas argument, page 60.
[1059] Exhibit 238.01, UCA-EDTI-08 b).
[1060] Exhibit 634.01, UCA argument, page 57, paragraph 314.
[1061] Exhibit 629.01, Calgary argument, page 52.

obligation to service by imposing economic discipline on siting decisions."[1063] The Commission agrees. As MILs increase, so do the capital costs of the companies. Therefore, MILs should be subject to the same incentives as other capital costs faced by the companies. As such, the Commission considers that to escalate MILs by I only removes incentives to seek additional efficiencies. This would be contrary to Principle 1 as incentives to seek efficiencies in the competitive market would be effectively lessened by escalating MILs by I only. Therefore, subject to the discussion of Fortis' MILs proposal below, the Commission directs that MILs be escalated by I-X throughout the PBR term.

850. Fortis proposed to escalate the MILs of residential (Rate 11) and street lighting (Rate 31) classes by an additional 10 per cent per year of the PBR term. The Commission finds that this proposal is consistent with Fortis' approach to MILs which was approved in Decision 2012-108 and necessary to bring its MILs in line with the other electric distribution companies.[1064] Therefore, the Commission directs that Fortis' MILs for these two classes be escalated by I-X plus 10 per cent per year throughout the PBR term.

13 Financial reporting requirements

851. Each utility proposed to file a copy of its Rule 005[1065] report in its annual PBR filing.[1066] AUC Rule 005 requires a utility to file schedules of financial and operational information including return on equity, detailed explanations of variances and audited financial statements complete with notes and an audit report. Under AUC Rule 005, all utilities are required to file their financial results by either May 1 for electric utilities or May 15 for gas utilities.

852. The UCA in its evidence noted that the minimum filing requirement (MFR)[1067] and general rate application (GRA) schedules, respectively filed by electric and gas utilities in their GRAs, provide much more detail than the Rule 005 schedules.[1068] Therefore, the UCA proposed that electric utilities be ordered to provide MFR schedules as part of their annual PBR filing, and that each gas utility file all the schedules included in its last GRA.[1069] The UCA argued that, if only the Rule 005 schedules were to be filed throughout a utility's PBR term, rebasing at the end

[1062] Decision 2000-01: ESBI Alberta Ltd., 1999/2000 General Rate Application Phase I and Phase II, Application No. 990005, File Nos. 1803-1, 1803-3, February 2, 2000.
[1063] Decision 2000-01, page 270.
[1064] Decision 2012-108, paragraphs 104-105.
[1065] Rule 005: *Annual Reporting Requirements of Financial and Operational Results* (Rule 005).
[1066] Exhibit 110.01, AltaGas PBR application, paragraphs 109 and 122; Exhibit 631.02, ATCO Electric argument, paragraph 328 and Exhibit 476.02, ATCO Electric rebuttal evidence, paragraphs 208-213; Exhibit 632.01, ATCO Gas argument, paragraph 343 and Exhibit 472.02, ATCO Gas rebuttal evidence, paragraphs 152-154; Exhibit 633.02, Fortis argument, paragraph 288(88); Exhibit 103.02, EPCOR PBR application, paragraph 256.
[1067] The minimum filing requirements were approved in Decision 2007-017: EUB Proceeding, Implementation of the Uniform System of Accounts and Minimum Filing Requirements for Alberta's Electric Transmission and Distribution Utilities, Application No. 1468565, March 6, 2007. This decision was the culmination of a consultation to determine a uniform system of accounts for electric utilities to implement, and the minimum filing requirements electric utilities must comply with in their general rate applications. See USA & MFR on the AUC's website under Items of Interest.
[1068] Exhibit 300.02, UCA evidence, Question 60.
[1069] Exhibit 634.02, UCA argument, paragraphs 417 to 421.

of the term would be far more difficult and it would be far more difficult to return to cost of service regulation.[1070]

853. The UCA further argued that the continuity of actual data would be lost over a utility's PBR term if the companies were not required to file annually the more detailed MFR and GRA schedules. This is because companies subject to the MFR are required to provide only two years of actual data in a cost of service general rate application.[1071]

854. Fortis and the ATCO companies argued being required to file the MFR and GRA schedules on an annual basis would increase regulatory burden.[1072] The UCA responded that the additional cost to provide the extra detail in the MFR and GRA schedules would be minimal.[1073] IPCAA stated that customers have paid and are paying for data collection in the USA/MFR format and should be afforded the right to receive all such data on an ongoing basis.[1074]

855. The UCA also recommended that "all utilities continue to exclude costs previously disallowed from the calculation of actual results and ROE during the PBR term."[1075] The UCA proposed that, to address its concern with respect to excluding disallowed costs, companies should file the two tables it had provided in ENMAX's FBR proceeding and which ENMAX was subsequently directed to provide in its annual rate applications. These two tables consist of a reconciliation of financial and utility returns, and a summary of disallowed and inappropriate costs.[1076]

13.1 Audits and senior officer attestation

856. AUC Rule 005 requires a reconciliation of the utility's financial results to its audited financial statements. Audited financial statements are intended to provide independent assurance on the accuracy and completeness of a utility's financial results. AUC Rule 005 does not require an audit of the Rule 005 schedules themselves. Because of disallowed costs, non-regulated operations, changes in accounting policies and other factors, the financial results reported by a utility in its audited financial statements may be different than those reported in AUC Rule 005 or may differ over several years.

857. AltaGas, in its application, proposed that as part of its annual rate application it would provide a senior officer attestation, in addition to a copy of its Rule 005 filing (which includes audited financial statements).[1077] AltaGas' proposed senior officer attestation appears to be based on the nine issues that the Commission directed ENMAX to have reviewed and commented on by an independent auditor in Decision 2010-146.[1078] The attestation by an AltaGas senior officer would provide assurance as to the veracity of the reported numbers and the calculations used, and transparency with respect to any changes in methods, policies or parameters affecting the reported results.

[1070] Exhibit 634.02, UCA argument, paragraph 420.
[1071] Exhibit 634.02, UCA argument, paragraph 419.
[1072] Exhibit 644.01, Fortis reply argument, paragraphs 174 and 175; Exhibit 648.02, ATCO Gas reply argument, paragraphs 529 and 530; Exhibit 647.01, ATCO Electric reply argument, paragraph 354.
[1073] Exhibit 300.02, UCA evidence, Question 65 on page 67.
[1074] Exhibit 642.01, IPCAA reply argument, paragraph 19.
[1075] Exhibit 634.02, UCA argument, paragraph 422.
[1076] Exhibit 300.02, UCA evidence, Question 69 and Question 70.
[1077] Exhibit 110.01, AltaGas Incentive Regulation application, paragraph 123.
[1078] Decision 2010-146: ENMAX Power Corporation, Decision 2009-035 Formula Based Ratemaking Compliance Application, Application No. 1604999, Proceeding ID. 191, April 22, 2010, paragraph 132.

858. The Commission in Decision 2009-035 directed ENMAX as follows:

> … to have its reported ROE independently verified and to have an officer of the company attest to its validity. The Commission also directs EPC to include in its annual filings the reconciliation tables proposed by UCA.[1079]

859. Subsequently, in Decision 2011-260, the Commission directed ENMAX to provide attestations and certifications by one of its senior officers for the following matters:[1080]

- that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- regarding the accuracy and/or completeness of the nine issues identified
- that the numbers, assumptions and proposed rates are reasonable, fair and accurate

Commission findings

860. The Commission agrees that the utilities' proposal to include the AUC Rule 005 schedules in their annual PBR filings is reasonable and accordingly directs each company to include in its annual PBR filing a copy of its AUC Rule 005 filing.

861. To maintain transparency and consistency, the Commission agrees with the UCA that disallowed costs should continue to be identified and excluded from a company's ROE. The Commission directs each utility to include in its annual PBR rate adjustment filing a schedule including the two UCA tables put forth by the UCA.[1081]

862. The Commission directs each company to include in its annual PBR rate adjustment filing an attestation signed by a senior officer of the company as proposed by AltaGas. The senior officer attestation should include, as applicable, not only those items proposed by AltaGas, but also certifications on the accuracy, completeness and reasonableness of the numbers and assumptions included in the company's application. The required attestations and certifications by a senior officer of each company are as follows:

- confirm the reported ROE used to determine if a re-opener exists, either actual or weather normalized
- describe any changes in accounting methods, including assumptions respecting capitalization of labour and overhead and associated impacts
- describe any changes in the depreciation parameters and associated impacts
- describe any changes in the allocation of shared services costs and associated impacts
- confirm the inflation parameters used, including calculation and application of the rates formula to rates
- confirm the calculation of flow-through costs (Y factors) and associated riders conform to Commission directions
- confirm the calculation of exogenous (Z factor) adjustments and associated riders conform to Commission directions

[1079] Decision 2009-035, paragraph 283.
[1080] Decision 2011-260: ENMAX Power Corporation, 2011 Formula Based Ratemaking Annual Rates and Technical Report, Application No. 1607203, Proceeding ID No. 1169, June 20, 2011, paragraph 58(5).
[1081] Exhibit 300.02, UCA evidence, page 74.

- confirm the calculation of capital trackers (K factor) and associated riders conform to Commission directions
- identify any material changes in the components of costs or revenues
- confirm that the numbers, assumptions and presentation of the numbers in the application are accurate, complete, and proper
- confirm that the numbers, assumptions and proposed rates are reasonable, fair and accurate

863. For a company under PBR, the requirement to file the AUC Rule 005 schedules in both its annual PBR rate adjustment filing and a separate AUC Rule 005 application, does not exempt the company from its obligation to maintain detailed accounts in accordance with the acts, regulations, Commission rules, or Commission decisions applicable to the company. Therefore, unless otherwise directed or exempted by the Commission, the companies are directed to maintain the ability to file a complete set of MFR and GRA schedules with actual results for all years within the term of the company's PBR plan. The companies are not required, however, to file a complete set of MFR and GRA schedules annually.

14 Service quality

864. Whereas an I-X mechanism creates efficiency incentives similar to those in competitive markets, it does not create incentives to maintain quality of service. In a competitive market, poor service quality will cause customers to switch companies, but poor service quality will not result in a loss of customers for a monopoly. The fact of monopoly supply of an essential public service has required regulators to monitor and regulate service quality. The Commission has recognized from the outset of its rate regulation initiative that the creation of greater efficiency incentives through adoption of a PBR plan also creates concerns that the resulting cost cutting might lead to reductions in quality of service. It is for this reason that the adoption of PBR typically coincides with the development and adoption by regulators of stronger quality of service regulatory measures when needed.

865. The Commission has the legislative authority under both the *Electric Utilities Act*[1082] and the *Gas Utilities Act*[1083] to make rules respecting service standards for electric utilities and for gas distributors. The Commission is also authorized to investigate compliance with the rules respecting service standards and, if necessary, is empowered to take steps to enforce them. This authority exists regardless of the type of ratemaking regime in operation, be it cost of service or performance-based regulation.

866. The first of the five principles (Principle 1) states, "A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality." All of the companies provided assurances in their submissions that service quality would not decline with the adoption of their proposed PBR plans. Notwithstanding these assurances, each of the interveners identified service quality degradation as a significant risk under PBR.[1084]

[1082] *Electric Utilities Act*, Section 129.
[1083] *Gas Utilities Act*, Section 28.3.
[1084] Exhibit 634.01, UCA argument, paragraph 368; Exhibit 307.01, PEG evidence for CCA, PDF page 65; Exhibit 635.01, IPCAA argument, paragraph 53; Exhibit 629.01, Calgary argument, PDF page 64.

867. In his evidence submitted on behalf of the UCA, Dr. Cronin reported the results of a study where he compared reliability statistics from Alberta electric distribution companies with selected companies in Ontario and the United States. Of the 22 companies Dr. Cronin described as higher density, ENMAX and EPCOR ranked first and third respectively for reliability. Among the lower density companies, Dr. Cronin described ATCO Electric and Fortis as having "superior reliability" compared to the 10 companies he examined. Dr. Cronin concluded from this analysis that "the AUC must be careful that the gains achieved to date are not put at risk for what could be limited potential gains under PBR."[1085]

Commission findings

868. The Commission has reviewed the service quality and reliability annual reports of the companies and agrees with the UCA that the service levels currently provided by the companies are acceptable.[1086] The Commission will require the companies to maintain their current levels of service quality throughout the PBR term.

14.1 Mechanism to monitor and enforce service quality

869. Currently, the Commission monitors service quality performance through AUC Rule 002.[1087] AUC Rule 002 sets out the service quality reporting requirements for electric utilities and gas distributors. Pursuant to this rule, all gas distributors and electric utilities under the jurisdiction of the Commission are required to file quarterly and annual performance reports.

870. Parties were divided as to whether the Commission should continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or whether the Commission should implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula. This latter approach, which is often referred to as a "Q factor" in the PBR formula, was adopted by the Commission in Decision 2009-035 for the ENMAX FBR plan. In the ENMAX FBR, the service standards were set out for the FBR plan and the penalties for failure to meet the standards were included as an adjustment to the formula.[1088]

871. ATCO Electric, ATCO Gas, AltaGas and Fortis favoured continued use of AUC Rule 002 for service quality reporting.[1089] The UCA stated that "Rule 002 should form the basis for service quality reporting under PBR."[1090] The CCA supported this approach.[1091]

872. EPCOR was in favour of the approach approved for the ENMAX FBR plan. In its view, AUC Rule 002 has significant limitations including the fact that it did not set out specified penalties, and it used the All Injury Incidence Frequency Rate metric instead of the Total Recordable Injury Frequency Rate metric that EPCOR proposed. EPCOR also argued in favour of its proposal because AUC Rule 002 applies only to owners of electric distribution systems and

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1085 Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 11-12.
1086 Service quality and reliability annual reports on AUC website.
1087 AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*, effective date July 1, 2010 (Rule 002).
1088 Decision 2009-035: ENMAX Power Corporation, 2007-2016 Formula Based Ratemaking, Application No. 1550487, Proceeding ID. 12, March 25, 2009, paragraphs 302-304.
1089 Exhibit 631.01, ATCO Electric argument, paragraph 284; Exhibit 632.01, ATCO Gas argument, paragraph 306; Exhibit 628.01, AltaGas argument, PDF page 80; Exhibit 474.01, Fortis rebuttal evidence, paragraph 58.
1090 Exhibit 634.01, UCA argument, paragraph 369.
1091 Exhibit 636.01, CCA argument, paragraph 357.

to gas distributors but not to transmission, whereas, EPCOR's proposal, like that of ENMAX, included metrics for transmission.[1092] EPCOR's proposal to adopt the approach approved for the ENMAX FBR aligned with EPCOR's proposal to include transmission in its PBR plan.

873. IPCAA was also critical of adopting AUC Rule 002 as, in its view:[1093]

> Traditional service quality metrics such as those contained in AUC Rule 002 have been accepted in the context of traditional rate-base regulation. For example, SAIDI [System Average Interruption Duration Index] and SAIFI [System Average Interruption Frequency index] provide a broad sense of "position in the pack," relative to other utilities across Canada (and elsewhere), but that is all the precision that they can potentially provide. [T16:3039.3].They are biased metrics, which over-report some phenomena and under-report other phenomena. [T16:3061.22]
> …
>
> Since these metrics are based on number of customers affected, they can lead to poor incentives. For example, a utility might have two projects to reduce these metrics: one to trim trees around ten summer cottages and one to maintain ten large sites' high voltage equipment. If optimizing to cost and CAIDI [Customer Average Interruption Duration Index] was the goal, the cottage project might seem far superior even though the social and economic costs of outages to the large sites are much greater. [T16:3039.6]
> …
>
> AUC Rule 002 does not provide for any financial incentives, and the penalties provided by the EUA [sic. AUCA] at section 63 do not allow for a performance bonus. A symmetrical incentive plan would therefore have to be incorporated into the PBR plans. [T06, p.1090.22]

874. Calgary also rejected the use of AUC Rule 002, because it generally requires ATCO Gas to report its operations, rather than requiring the company to meet "specific performance criteria or standards."[1094]

Commission findings

875. The Commission has considered the advantages and the disadvantages of each of the two alternative proposals for monitoring and enforcing service quality: to continue to use AUC Rule 002 for monitoring service quality along with an enforcement mechanism such as administrative monetary penalties, or to implement a performance standard mechanism within the PBR plan itself that also includes penalty adjustments for non-compliance in the formula.

[1092] Exhibit 630.02, EPCOR argument, paragraph 296.
[1093] Exhibit 635.01, IPCAA argument paragraphs 50, 51 and 93.
[1094] Exhibit 629.01, Calgary argument, PDF page 65.

876. The following table sets out the metrics that are currently required to be reported by electric distribution utilities under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-1 Current AUC Rule 002 metrics for electric distribution utilities

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Monthly billing and meter reading performance	No
	Cumulative meters not read within six months	Yes
	Identified meter errors	No
	Monthly tariff billing performance	Yes
Work completion performance measures	Energizing sites	No
	De-energizing sites	No
	Performing off-cycle meter reads	No
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Reliability performance measures	System average interruption frequency index (SAIFI)	No
	Customer average interruption duration index (CAIDI)	No
	System average interruption duration index (SAIDI)	No
	SAIDI of worst-performing circuits on the system	No
Post-final adjustment mechanism (PFAM) adjustments processed	Post-final adjustment mechanism (PFAM) adjustments processed	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

877. The following table sets out the metrics that are currently required to be reported by gas distributors under AUC Rule 002 and indicates whether or not each metric has a defined target:

Table 14-2 Current AUC Rule 002 metrics for gas distributors

Performance category	Metric	Defined targets
Billing and meter reading performance measures	Cumulative meters not read within four months and one year	No
	Monthly tariff billing performance	Yes
Worker safety performance measures	All injury/illness frequency rate	No
	Motor vehicle incident frequency	No
Customer satisfaction measures	Percentage of customer satisfaction following customer-initiated contact with the owner	Yes
	Overall customer satisfaction measures	Yes
	Complaint response	Yes

878. The Commission also monitors call centre statistics, such as call answer time and abandon rates, in AUC Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers and Default Supply Providers* (Rule 003) because, in Alberta, call centre and billing functions are performed by competitive retailers, regulated rate providers and default supply providers. The electric utilities and gas distributors generally only field emergency calls from customers or calls from retailers.

879. In addition to filing quarterly and annual performance reports, another AUC Rule 002 requirement is for the company to meet with the Commission at least once annually after submission of its AUC Rule 002 annual report to discuss:

- service quality issues
- trends in service quality data reported by the owner, including any corrective action plans proposed by the owner to remedy failing performance standards
- issues raised by customer complaints filed with the Commission
- other policy issues related to customer service[1095]

880. In the Commission's view, using AUC Rule 002 together with a penalty provision has the following advantages:

- As a rule, the performance metrics already included in AUC Rule 002 were developed and updated in consultation with industry stakeholders.
- Continuity of the metrics and how they are reported will allow for trend analysis, especially for those metrics which have been in place since 2004. The Commission can rely upon historical databases to identify any negative trends in service quality and take corrective action if service levels decline.
- Companies may make decisions and take actions during the PBR term which may have consequences not readily apparent during the term. Using AUC Rule 002 will enable the

[1095] AUC Rule 002, Section 2.3.

Commission to monitor the consequences of those actions after the PBR term expires, regardless of the rate-setting mechanism in place after the end of the term.

- As is discussed further in Section 14.2, if AUC Rule 002 is accompanied by a penalty provision rather than including penalties as an adjustment to the PBR formula, unexpected and potentially undesirable impacts to consumer behaviour can be avoided. For example, if rates were lowered because of a penalty that adjusted the formula, certain price sensitive consumers may react by choosing to consume more energy which, in turn, could potentially increase revenues for the company. In such an event, incurring a penalty may result in a financial benefit to the company.

881. Having considered both the advantages and disadvantages of the two mechanisms proposed, the Commission finds that adopting AUC Rule 002 to determine performance standards and targets, and applying penalties in the event of non-compliance with the performance targets established, is the best approach for ensuring that the companies have an adequate incentive to maintain service quality under PBR.

882. The Commission is satisfied that, with the addition of new metrics and with the establishment of defined targets for those metrics currently without them, AUC Rule 002 will satisfactorily address the requirement for service quality measurement and reporting under PBR. As the Commission has determined in Section 2.4 of this decision that it will not include transmission as part of any PBR plan, it will, therefore, not be necessary to develop any performance measures for transmission at this time.

883. Accordingly, the Commission will initiate a consultation process before the end of 2012 to review and revise AUC Rule 002 in a timely manner. The companies and interveners will be invited to participate in the consultation process.

14.2 Penalties and rewards

884. AUC Rule 002 does not include provisions for penalties in the event that performance standards are not met. All parties agreed that some kind of enforcement mechanism is necessary. None of the companies argued against penalties for failure to meet service quality targets, when the failure was within their control.[1096]

885. Calgary recommended penalties and stated "the PBR plan should include direct fines paid by the utility for specific infractions; the fines should be treated as an addition to the next ESM payment or at the end of the PBR term."[1097]

886. The UCA recommended specified penalties of 10 per cent of earnings and stated:

> In a competitive market, poor performance is met with a lawsuit or more likely the loss of a customer, without any process to explain the reason for poor performance. As customers of a regulated utility have no choice to change suppliers, a specified penalty, with certainty as to the impact of poor performance is simpler to administer. Also, there

[1096] Exhibit 219.02, Fortis response to AUC-FAI-020 ALLUTIL (b), PDF page 35; Exhibit 628.01, AltaGas argument, PDF page 84; Exhibit 103.02, EPCOR PBR application, paragraph 91; Exhibit 631.01, ATCO Electric argument, paragraph 308; Exhibit 632.01, ATCO Gas argument, paragraph 326.

[1097] Exhibit 629.01, Calgary argument, page 63.

> is no evidence that customers want or are willing to pay for improved service levels, so the concept of a reward is not supported by the evidence.[1098]

887. IPCAA recommended a symmetrical approach to address service quality issues. That is, IPCAA proposed that penalties for degradations to service quality be instituted but also, if service quality improves, that a performance bonus plan be instituted.[1099]

888. EPCOR stated in its application that it "will explain the reasons for failing to meet the target as well as any future corrective actions EDTI proposes to take."[1100] While EPCOR only implied that the penalty would not apply if it adequately justified the failure, the other companies clearly argued for an opportunity to have their failures reviewed prior to a penalty being administered.[1101]

889. ATCO Electric and ATCO Gas expressed concerns that they would be penalized for events outside of their control and, therefore, recommended that, if they would be subject to penalties for events outside of their control, they should also be entitled to receive rewards where service targets are exceeded due to events outside their control in order to balance the increased risk, if penalties were automatic without opportunity for review.[1102] Fortis, in its application, did not request rewards for higher than standard service quality[1103] but on cross-examination recommended an approach with both penalties and rewards.[1104] AltaGas submitted that higher than required service quality levels should be met with rewards if a system of penalties is in place.[1105]

890. EPCOR proposed a reward for meeting its service quality standards throughout the five-year PBR term, to be specifically included in an efficiency carry-over mechanism for two years after the end of the PBR term.[1106]

891. Regarding the size of the penalties, ATCO Electric stated:

> The Commission makes the determination of whether a penalty is required and the appropriate amount would be commensurate with the benefit gained by the utility as a result of its actions.[1107]

892. ATCO Gas made a statement similar to the one made by ATCO Electric[1108] and continued:

> The magnitude of 10% of earnings recommended by the UCA is unreasonable. As ATCO Gas has already stated, there is a realistic likelihood that it will be penalized for events

[1098] Exhibit 649.02, UCA reply argument, paragraph 246.
[1099] Exhibit 635.01, IPCAA argument, paragraph 93.
[1100] Exhibit 103.02, EPCOR PBR application, paragraph 93.
[1101] Exhibit 628.01, AltaGas argument, PDF page 83; Exhibit 631.01, ATCO Electric argument, paragraph 306; Exhibit 632.01, ATCO Gas argument, paragraph 324; Exhibit 100.02, Fortis PBR application, paragraph 131.
[1102] Exhibit 647.01, ATCO Electric reply argument, paragraph 330; Exhibit 648.02, ATCO Gas reply argument, paragraph 502.
[1103] Exhibit 100.02, Fortis PBR application, paragraph 138.
[1104] Transcript Volume 11, page 2182.
[1105] Exhibit 650.01, AltaGas reply argument, paragraph 265.
[1106] Exhibit 103.02, EPCOR PBR application, paragraph 272.
[1107] Exhibit 647.01, ATCO Electric reply argument, paragraph 331.
[1108] Exhibit 648.02, ATCO Gas reply argument, paragraph 503.

> that were not within its ability to control. A penalty of 10% of earnings, which is in the order of $6 million for ATCO Gas, related to something ATCO Gas could not control is absurdly confiscatory. Penalties must not be so great as to have a significant negative impact on ATCO Gas' ability to recover its prudently incurred costs, including a Fair Return on its investments. The penalty should be commensurate with the benefit gained…[1109]

893. ATCO Electric, too, had concerns with having penalties as high as 10 per cent of earnings.[1110] Fortis and AltaGas did not discuss the size of the penalties in their final arguments or reply arguments.

894. EPCOR, however, proposed that a failure to reach any one service quality metric should result in a $250,000 penalty per year. Under EPCOR's proposed PBR plan, it would be penalized $1 million in 2013 if it failed to reach all four of its proposed metrics, and the $1 million would be escalated by I-X in subsequent years.[1111] However, EPCOR indicated that it would be applying to the Commission for an adjustment to two of its four performance targets and for relief from those targets for 12 months after implementation of its Outage Management System/Distribution Management System.[1112]

895. The UCA, in its reply argument, expressed concerns over EPCOR's proposal to be penalized $250,000 per failed target, stating:

> Further, having the penalty split between four measures, means that failing to meet one measure would result in a penalty of only $0.25 million, which is not material, and may not be sufficient to deter the conduct. It may well lead to the concern raised by the Chair that the utility will simply factor the fine into the economics of their decisions.[1113]

Commission findings

896. Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act* provide the legislative authority for the Commission to take any or all of the following actions when the Commission is of the opinion that an owner of an electric utility or a gas distributor has failed or is failing to comply with its rules respecting service standards. These provisions state as follows:

> *Electric Utilities Act*
> 129(3) If the Commission is of the opinion that the owner of an electric utility has failed or is failing to comply with the rules respecting service quality standards, the Commission may by order do all or any of the following:
>
> (a) direct the owner to take any action to improve services that the Commission considers just and reasonable;
> (b) direct the owner to provide the customer with a credit, of an amount specified by the Commission, to compensate the customer for the owner's failure to comply with the rules respecting service quality standards;

[1109] Exhibit 648.02, ATCO Gas reply argument, paragraph 509.
[1110] Exhibit 647.01, ATCO Electric reply argument, paragraph 337.
[1111] Exhibit 630.02, EPCOR argument, paragraph 316.
[1112] Exhibit 630.02, EPCOR argument, paragraph 294.
[1113] Exhibit 649.02, UCA reply argument, paragraph 258.

(c) prohibit the owner from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

Gas Utilities Act
28.3(3) If the Commission is of the opinion that the gas distributor or default supply provider has failed or is failing to meet the service standards rules, the Commission may by order do all or any of the following:

(a) direct the gas distributor or default supply provider to take any action to improve services that the Commission considers just and reasonable;
(b) direct the gas distributor or default supply provider to provide the customer with a credit, in an amount specified by the Commission, to compensate the customer for the gas distributor's or default supply provider's failure to meet the service standards rules;
(c) prohibit the gas distributor or default supply provider from engaging in any activity or conduct that the Commission considers to be detrimental to customer service;
(d) impose an administrative penalty under section 63 of the *Alberta Utilities Commission Act*.

897. An administrative penalty under Section 63 of the *Alberta Utilities Commission Act* may require the person to whom it is directed to pay either or both of the following:

(a) An amount not exceeding $1 million for each day or part of a day on which the contravention occurs or continues.

(b) A one-time amount to address economic benefit where the Commission is of the opinion that the person has derived an economic benefit directly or indirectly as a result of the contravention.

898. The Commission considers that these legislative remedies provide the following benefits in dealing with a failure to maintain service quality standards during the PBR term:

- The potential size of the penalties under Section 63 along with the power to direct disgorgement of any economic benefits discourages service quality degradation.
- If service quality failures occur, the size of the penalty can be tailored to match the benefit gained by the company as a result of its action.
- The review process in administering the penalty allows the company the opportunity to explain the source or cause of the failure and argue that a penalty is not warranted or should be lessened.

899. The Commission rejects any proposal that a performance bonus should be available to the companies in the event that service quality targets are exceeded. As noted throughout this decision, the objective of a PBR plan is to incent behaviour that would be similar to that of a company in a competitive market. But, in a competitive market, a company may increase its service quality and charge a higher price, but risks losing customers. For monopoly utility companies, there is no risk of losing customers. Customers have no choice but to pay the higher

price for a service quality level that they may not want or cannot afford.[1114] Further, if the industrial customers that IPCAA represents want a higher level of service quality, they can elect to contract directly with the companies for that purpose at a negotiated price.

900. For the above reasons, the Commission will continue to rely on these legislative provisions, including the imposition of penalties, to address enforcement issues should service quality degrade.

14.3 Consultation process

901. The Commission in this decision is setting out directions for the AUC Rule 002 consultation for the following issues to assist parties participating in the consultation process:

a. Annual review meetings
b. Additional service quality metrics
c. Setting targets and penalties
d. Asset management reporting
e. Line losses (electric distribution companies only)

14.3.1 Annual review meetings

902. Parties provided their views on the format and content of the AUC Rule 002 annual review meetings. With respect to format, parties discussed the inclusion of interveners at the meetings, which previously only included the Commission and company staff. While some parties had no objection to including customer groups at the meetings,[1115] others expressed concern that such a change would be better addressed in a consultative process.[1116]

903. With respect to content, Fortis proposed expanding the scope of the review meetings to include an evaluation of outage causes and a discussion of asset management programs.[1117]

Commission findings

904. The Commission is not opposed to the inclusion of interveners at the annual review meetings. Proposed changes to the process and scope of the annual review meetings, including intervener attendance, will be further discussed in the upcoming AUC Rule 002 review consultative process referenced in Section 14.1, at which the roles of parties in the annual review meeting will be established.

14.3.2 Additional service quality performance metrics

905. Several interveners urged the Commission to adopt additional service quality performance metrics beyond those already identified under AUC Rule 002.

[1114] See discussion at Transcript, Volume 14, page 2892 to 2894.
[1115] Exhibit 628.01, AltaGas argument, page 79, Exhibit 631.01, ATCO Electric argument, paragraph 309, Exhibit 633.01, Fortis argument, paragraph 274.
[1116] Exhibit 629.01, Calgary argument, PDF page 68, Exhibit 648.02, ATCO Gas reply argument, paragraph 510, Exhibit 635.01, IPCAA argument, paragraph 94.
[1117] Exhibit 633.01, Fortis argument, paragraph 274.

906. The UCA recommended three new service quality performance metrics:

- service appointments met/time
- response time for emergency calls
- reconnect after cut off for nonpayment (CONP) response time[1118]

907. The CCA recommended that line losses be monitored and that additional metrics be put in place for transmission.[1119]

908. IPCAA was interested in having the following metrics or data sources included in the reporting requirements:

- system-level outage data
- outage information sent to customers as a part of the interval meter data set
- transmission measures[1120]

909. Calgary recommended that the Commission look to other jurisdictions for best practices and referenced the Gaz Métro Performance Incentive Mechanism Decision and Analysts' Presentation. The referenced document contains the following metrics:[1121]

- preventive maintenance
- emergency response time
- telephone response time
- meter reading frequency
- ISO 14001 (environmental management systems)
- greenhouse gas emissions
- customer satisfaction by customer class
- collection & service interruption procedure

910. EPCOR, ATCO Electric, ATCO Gas and Fortis did not favour the addition of the new metrics proposed by the UCA.[1122] AltaGas was not opposed to the addition of the metrics proposed by the UCA but indicated that any additions should be accomplished through a consultation process.[1123]

911. Fortis,[1124] ATCO Electric[1125] and EPCOR[1126] also opposed the addition of the metrics proposed by IPCAA.

1118 Exhibit 634.01, UCA argument, paragraph 383.
1119 Exhibit 636.01, CCA argument, paragraphs 358-360.
1120 Exhibit 635.01, IPCAA argument, paragraph 59-75.
1121 Exhibit 546.01, undertaking Carpenter to McNulty, PDF page 25.
1122 Exhibit 630.02, EPCOR argument, paragraphs 305 and 306; Exhibit 631.01, ATCO Electric argument, paragraph 294; Exhibit 632.01, ATCO Gas argument, paragraph 316; Exhibit 633.01, Fortis argument, paragraph 263.
1123 Exhibit 650.01, AltaGas reply argument, paragraph 259.
1124 Exhibit 644.01, Fortis reply argument, paragraphs 158 and 161.
1125 Exhibit 647.01, ATCO Electric reply argument, paragraph 321.
1126 Exhibit 473.02, EPCOR rebuttal evidence, page 32.

Commission findings

912. The Commission has considered the recommendations of the parties as well as information they provided on the record of the proceeding with respect to the practices in other jurisdictions. Based on this review, the Commission considers that there is insufficient evidence for the Commission to make a determination as to whether it is in the public interest to impose the new metrics proposed by the parties. Therefore, the Commission will be seeking further information on the metrics proposed as additions to AUC Rule 002 in the upcoming AUC Rule 002 consultation process.

14.3.3 Target setting and penalties

913. Several parties recommended that the Commission adopt a specific approach to set targets for those metrics under AUC Rule 002 that do not currently have defined performance targets.

914. In his evidence for the UCA, Dr. Cronin recommended the use of a willingness-to-pay study to set a socially optimal level of reliability or, as Dr. Cronin explained, "the level of reliability where the marginal benefits from improvements equal the marginal costs of implementation."[1127] In testimony, Dr. Cronin described it as "trying to elicit from, say customers in this instance, how they value the reliability they receive from the company."[1128] Dr. Cronin also indicated in testimony that different customer classes would be willing to pay differing amounts for reliability improvements and that customers' willingness to pay would change over time.[1129]

915. In his rebuttal testimony on behalf of EPCOR, Dr. Weisman expressed his concerns with Dr. Cronin's recommendation:

> …this approach would seem to be ruled out by AUC PBR Principle 1: A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality. With this principle, the Commission has seemingly carved out a special exception for service quality. To wit, the AUC wishes to implement PBR regimes that replicate the incentive structure of a competitive market, "while maintaining service quality." Hence, even if service quality for Alberta utilities is currently over-provisioned from a social welfare perspective—service quality is "too good"—the Commission does not wish to see any fall off in the level of service quality that Albertans currently enjoy.[1130]

916. ATCO Electric also commented on Dr. Cronin's recommendation stating:

> ATCO Electric notes that the costs associated with providing the current level of service quality and reliability have been incurred and approved as prudent by the AUC, and cannot simply be undone if a WTP [willingness-to-pay] study indicates that the "socially optimal" level of service is something lower than the current level. While the results of these kinds of studies might be interesting, ATCO Electric is unsure of how they might actually be used and it is unclear as to how the costs of these studies will be addressed.[1131]

[1127] Exhibit 299.02, Cronin and Motluk UCA evidence, page 205.
[1128] Transcript, Volume 17, pages 3293-3296.
[1129] Transcript, Volume 17, pages 3293-3296.
[1130] Exhibit 473.09, rebuttal testimony of Dennis L. Weisman, Ph.D., pages 13-14.
[1131] Exhibit 631.01, ATCO Electric argument, paragraph 292.

917. For the interim period, prior to completion of the proposed willingness-to-pay research, the UCA proposed the following approach for setting targets:

> …the target for service levels should be based on current levels achieved. These are the levels included in going-in rates, and are the levels that customers are paying for. A five year average of actual achieved performance prior to the start of PBR is the best indication of the current level of performance achieved.[1132]

918. EPCOR,[1133] ATCO Gas[1134] and ATCO Electric[1135] argued that a target based on a simple five-year average would require improvements in service quality to avoid penalties half the time, and therefore the companies proposed setting a threshold of one standard deviation above the average to account for the volatility of the measurements due to factors outside of their control. In addition, EPCOR was concerned that the reporting of annual numbers against the five-year average plus one standard deviation would incent a company to further reduce its costs in years where it had no hope of achieving a performance target, since the poor measurement in one year would not impact future years' measurements. EPCOR, therefore, proposed that it report a five-year rolling average against the target so that "poor performance in one year would be reflected in the rolling average for the next four years, incenting the utility to continue to take steps and spend dollars to minimize the extent of its poor performance in the original year."[1136]

919. The UCA expressed concern over EPCOR's proposal to report a five-year rolling average, stating, "While I understand that an average will allow the impact of anomalies to be minimized, it will also mask any trends in degradation of service levels."[1137] In final argument, the UCA suggested that the removal of major events from the average would resolve the problem of volatility in the data and the likelihood of a penalty being imposed while service quality remained the same.[1138]

920. ATCO Gas and ATCO Electric rejected the UCA's suggestion to remove major events stating that removing " 'major events' just means that there is a requirement to make improvements over the current level on all other events."[1139] EPCOR provided a similar response and indicated that "service quality can be significantly impacted in a given year by varying volumes of smaller outages that, just like MEDs [major event days], are beyond EDTI's ability to control."[1140]

921. For the new service measures that the UCA wanted introduced, it stated that the measures should be tracked initially to establish a performance history because without history "there can

[1132] Exhibit 634.01, UCA argument, paragraph 381.
[1133] Exhibit 473.02, EPCOR rebuttal evidence, PDF page 21.
[1134] Exhibit 648.02, ATCO Gas reply argument, paragraph 493.
[1135] Exhibit 647.01, ATCO Electric reply argument, paragraph 316.
[1136] Exhibit 473.02, EPCOR rebuttal evidence, A12, PDF page 23.
[1137] Exhibit 300.02, UCA evidence of Russ Bell, A9, PDF page 14.
[1138] Exhibit 634.01, UCA argument, paragraph 382.
[1139] Exhibit 648.02, ATCO Gas reply argument, paragraph 494; Exhibit 647.01, ATCO Electric reply argument, paragraph 317.
[1140] Exhibit 646.02, EPCOR reply argument, paragraph 296.

be no meaningful targets set and therefore no penalties should be associated with the measures at this time."[1141]

922. The CCA, like the UCA, did not support setting a target with a standard deviation above average and recommended that "the performance measure, in each of the PBR test years, simply be the rolling average of the last 5 years of actual reported data."[1142] In other words, the target would change every year as the average changes over time.

923. In addition to concerns with the lack of a threshold above the average, EPCOR also argued that the CCA recommended approach "could result in degradation of service quality over time contrary to PBR Principle 1, as the targets could degrade as performance degrades."[1143] Fortis, ATCO Electric, ATCO Gas and AltaGas did not comment on the CCA's recommended approach.

924. Calgary in argument stated:

> There is no evidence on the record that ratepayers are seeking service levels superior to the existing service, particularly for residential and general commercial customers. Moreover, as was recognized by an AltaGas witness, the marginal cost of improving quality of service may well exceed the benefit.[1144]

925. IPCAA recommended "a consultative process be initiated to disclose what system-level outage data is retained by each utility, and explore efficient ways of using that data to set reliability targets and incentives."[1145]

926. An additional concern was raised by ATCO Electric,[1146] Fortis and EPCOR[1147] regarding how adjustments were to be made to setting targets as a result of the more accurate and detailed level of reporting that would be made available as a result of the implementation of their respective outage management systems. Fortis stated in testimony:

> So FortisAlberta is now implementing an outage management system. So whereas before we had 350 PLTs [power line technicians] independently inputting data manually, we will now move to a centralized process that will give us much better data, and that will cause SAIDI and SAIFI to increase, which if we'd stuck with the statistic itself, would imply the reliability has gotten worse, but reliability hasn't changed.[1148]

927. Similarly, EPCOR indicated that it would be applying for revisions to its SAIDI and SAIFI performance targets after it implements its outage management system.[1149]

[1141] Exhibit 634.01, UCA argument, paragraph 384.
[1142] Exhibit 636.01, CCA argument, paragraph, 371.
[1143] Exhibit 646.02, EPCOR reply argument, paragraph 297.
[1144] Exhibit 629.01, Calgary argument, PDF page 67.
[1145] Exhibit 635.01, IPCAA argument, paragraph 60.
[1146] Exhibit 631.01.AE-566, ATCO Electric argument, paragraph 297.
[1147] Exhibit 630.02, EPCOR argument, paragraph 294.
[1148] Transcript, Volume 11, pages 2179-2180.
[1149] Exhibit 630.02, EPCOR argument, paragraph 294.

Commission findings

928. The Commission has evaluated the various proposals put forward by the parties to set targets. With respect to the willingness-to-pay study proposed by the UCA, the Commission does not consider that such a proposal is necessary. Although a willingness-to-pay study may provide valuable information if the Commission were trying to ascertain whether Alberta distribution companies were providing a socially optimal level of reliability, at this time, the evidence on the record of this proceeding demonstrates that reliability standards are acceptable. Customer satisfaction scores are already provided by the companies on an annual basis as a part of the AUC Rule 002 results. The Commission is of the view that declining customer satisfaction scores will be a timely indicator of problems. For all of these reasons, the Commission rejects the UCA's proposal to use a willingness-to-pay study to set target measures at this time.

929. With respect to specific proposals of parties for setting service quality targets, the Commission will consider these proposals in the upcoming AUC Rule 002 consultative process.

930. In addition to establishing new measures and setting targets for those metrics currently without targets, the Commission considers that it is important that companies and Alberta customers understand the consequences that could result from a company's failure to meet service quality targets. This is particularly critical if a pattern of consistent failure arises. Therefore, through the upcoming AUC Rule 002 consultation process, the Commission will develop a penalty structure for these metrics as part of the administrative penalty scheme authorized under Section 129(3) of the *Electric Utilities Act* and Section 28.3(3) of the *Gas Utilities Act*. The Commission expects that this penalty structure will include escalating penalty amounts commensurate with repeated violations of the targets up to and including the maximum administrative penalty set out in Section 63 of the *Alberta Utilities Commission Act.*

931. Following the completion of the consultative process the Commission will issue a bulletin indicating the process to be followed with respect to the adjudication of penalties including a hearing or other proceeding.

14.3.3.1 Asset condition monitoring

932. Service quality and the physical condition of assets are linked. Companies cannot provide consistently reliable service without a well-functioning physical infrastructure. Parties suggested that the Commission must determine whether it is sufficient to monitor only the resulting service quality or whether it is necessary to also monitor the actions of the companies to ensure that the companies do not maintain service quality during the PBR term, but reduce their costs by allowing certain assets to degrade as a result of aging and deterioration, to then be replaced in capital programs that have been delayed to the post-PBR period.

933. In the proceeding, a number of approaches were proposed that ranged from companies simply reporting their current practices for increased transparency to recommendations that advocated Commission and intervener involvement in the development of policies and best practices for the companies.

934. The UCA proposed that the Commission "direct utilities to develop and file an asset management framework using the asset management discipline as envisioned by The Woodhouse Partnership Limited (TWPL)."[1150] The UCA was not in support of the type of asset

[1150] Exhibit 634.01, UCA argument, paragraph 387.

management study being conducted by EPCOR, which the UCA classified as a study of asset condition.[1151]

935. IPCAA proposed to exclude power system assets from PBR until such a time as service quality and asset condition metrics can be developed[1152] through a Commission-led consultation process.[1153] IPCAA's proposal is to include only general and administration costs in PBR.

936. In response to IPCAA's proposal, the CCA stated:

> In our view, if the AUC is not inclined to adopt IPCAA's recommendation, the AUC should convene a consultative process which would review the existing practices and lead to a determination of appropriate asset-condition metrics with the goal the metrics so determined would be applicable for the balance of the PBR term.[1154]

937. Calgary stated that asset management and data disclosure should be addressed in a collaborative process.[1155]

938. All of the distribution companies were opposed to the increased regulatory burden that could result with having asset management as a part of PBR. AltaGas submitted that "the monitoring of asset condition may be of limited value, particularly given the different vintages and terrains applicable to different service territories which may impact the results of such surveys."[1156]

939. ATCO Gas indicated in its final argument that asset management metrics would hamper its ability to be innovative:

> How can ATCO Gas try to find innovative, efficient ways of doing things like valve inspections, for example, if it is required to meet a standard that specifies exactly how it will undertake those valve inspections? ATCO Gas agreed with Dr. Makholm that the measures need to be objective and measurable and focus more on the output of the utility.[1157]

940. In EPCOR's opinion, "a process to review and assess asset condition data would be extremely complex, time consuming and costly resulting in substantial additional costs being borne by rate payers."[1158]

941. ATCO Electric stated in its final reply argument:

> IPCAA recommends a consultative process be initiated to identify key asset condition data which should be provided by the utility to customers and the regulator. ATCO Electric views this request to be without merit as the provision of the data by itself is without value as it requires an engineering analysis and assessment within an overall

1151 Exhibit 634.01, UCA argument, paragraph 388.
1152 Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 3.
1153 Exhibit 306.01, VIDYA Knowledge Systems evidence on behalf of IPCAA, PDF page 13.
1154 Exhibit 645.01, CCA reply argument, paragraph 216.
1155 Exhibit 629.01, Calgary argument, page 66.
1156 Exhibit 650.01, AltaGas argument, page 77.
1157 Exhibit 632.01, ATCO Gas argument, paragraph 321.
1158 Exhibit 630.02, EPCOR argument, paragraph 313.

asset management program as was described by Ms. Bayley during testimony. This is completely contrary to the AUC principle of reducing regulatory burden."[1159]

942. In an excerpt from Fortis' testimony, Mr. Delaney stated:

> We have a million poles, 100,000 kilometres of line. Coming from that, we've developed a number of programs. We have a pole management program where we do life extension of poles, and we are embarking on an effort to get 1940s and 1950s vintage poles out of our system that have 30 percent or more failure rates. We have an underground cable management program where we rejuvenate and extend the life of underground cables, pad mount transformer maintenance program with predicted maintenance, oil sampling. Well, I can go on. We have switch maintenance. We have a number of programs associated with all of our assets… And I understand certainly the Commission's point of view on this that -- but it's a tough thing to regulate without, you know, violating Principle 3, given the complexity of all these things. Now, there are avenues. There is envisioned an annual meeting, whether it's under Rule 2 or some other aspect that could be sort of a technical conference thing could be added on where utilities can give -- well, probably give things like a breakdown of what's happened in reliability over the past year, which we kind of do right now under Rule 2 in terms of what happened. Another -- but it's going to be a very, very complex exercise to establish input measures and then what do you make of them once you've established them. The utility must have the flexibility to move within its asset maintenance program to do what needs to be done prudently. And if we were to introduce process that involves information responses and thousands of -- a big process like that, then my engineers and people that were looking to find innovation and find good things to do to reduce our costs will be -- we'll take that regulatory burden.[1160]

Commission findings

943. While the companies are opposed to the increased regulatory burden from the introduction of asset management monitoring practices, the Commission sees potential benefits from asset management reporting. The purpose of asset management monitoring is to provide increased visibility into the asset management practices of the companies. It is not to replace the management of assets by the companies. Indeed, IPCAA's witness, Mr. Cowburn, acknowledged that this was not the purpose of asset condition disclosure.[1161] Rather, regular reporting of asset condition will give the Commission and stakeholders some insight into the condition of the companies' assets. Information about asset condition will improve the Commission's ability to develop quality of service metrics as well as assess capital tracker applications as discussed in Section 7.3.

944. Having determined that some asset management monitoring will be required, the Commission is of the view that stakeholders and the Commission would benefit from an AUC consultative process to develop reporting requirements. This consultation will be separate from the process discussed above with respect to AUC Rule 002. The Commission anticipates that it will conduct a distribution company round-table on this matter after the commencement of the PBR term.

[1159] Exhibit 647.01, ATCO Electric reply argument, paragraph 326.
[1160] Transcript, Volume 11, pages 2177-2179.
[1161] Transcript, Volume 16, pages 3131 to 3132

945. The Commission will, after consultation with stakeholders, develop an asset management monitoring process to report on the condition of distribution assets with the intention of providing transparency while allowing the companies to manage their assets and operations. In so doing the Commission will seek to limit any additional regulatory burden.

14.3.3.2 Line losses

946. Electricity retailers are charged for all electricity entering the distribution system from the transmission system. Some electricity is lost as a result of the transfer of energy across electric distribution systems, including distribution lines, transformers and regulators. This lost electricity is referred to as technical losses.[1162] Other electricity may be consumed but not recognized as used or sold for a variety of reasons, such as meter reading errors, meters not read, unmetered sites incorrectly estimated and energy theft. This type of loss is referred to as unaccounted-for-energy or non-technical losses.[1163]

947. ENMAX filed a line loss proposal as a complement to its FBR plan. This proposal had been developed in discussion with a number of interveners and was approved by the Commission in Decision 2009-226. The proposal created an incentive for ENMAX to reduce levels of line losses and assume the risk from investments made to reduce the losses. If there were savings from the reduction in line losses, ENMAX and the customers shared equally in those benefits.[1164] ENMAX reported that, as a result of this incentive plan, $0.854 million has been saved by its consumers in 2009 and 2010.[1165]

948. On behalf of the UCA, Dr. Cronin stated that for line losses "we find that the Alberta LDCs again compare very well" to the Ontario LDCs.[1166] However, IPCAA, the UCA and the CCA all expressed concerns regarding the potential risk that line losses could increase from current levels under PBR.[1167]

949. IPCAA recommended that the way to address the potential risk that line losses may increase under PBR was to "mitigate the potential drivers of such increases." IPCAA elaborated by stating:

> If asset management processes are made available and equipment selection criteria can be reviewed in an open, consultative process, any changes in utility equipment specifications leading to higher losses will be known and understood as they occur… Information transparency is preferred over blanket requirements in order to maintain line losses at a specific level [CCA-Exhibit 636, page 123], as there may be a good economic justification for the selection of different equipment."[1168]

1162 Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(ll), PDF page 35.
1163 Exhibit 218.01, ATCO Electric IR responses to UCA, UCA-ALLUTIL-AE-4(ll), PDF page 35.
1164 Exhibit 297.01, ENMAX evidence, PDF page16.
1165 Exhibit 297.01, ENMAX evidence, PDF page16.
1166 Exhibit 299.02, Cronin and Motluk UCA evidence, PDF page 11.
1167 Exhibit 642.01, IPCAA reply argument, paragraph 60; Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 183-185; Exhibit 636.01, CCA argument, paragraph 360.
1168 Exhibit 642.01, IPCAA reply argument, paragraphs 60-61.

950. The UCA recommended that each applicant should develop a line loss proposal which should either involve a mechanism to adjust the rates or a set of incentives similar to the ENMAX approach.[1169]

951. The CCA submitted that EPCOR's plan should include:

> …a specific provision that its line losses during the PBR Term will not be any lower than that observed for the 3-year average period prior to the start of the PBR term i.e. average of 2.633% for the period 2009-2011, inclusive, per X239.01, UCA-ALLUTILITIES-4 (mm).[1170]

952. Fortis, EPCOR and ATCO Electric rejected the inclusion of a line loss proposal as suggested by the interveners. Fortis stated that it already "has ongoing system design and standards programs in place that focus on loss minimization, as well as an ongoing capital project that looks for loss reductions on specific lines. Any incremental line loss program would be duplicative and unnecessary."[1171] EPCOR expressed concern that it is already operating near the low end of what is physically achievable, that theft is outside of the direct control of the company and non-technical losses are already monitored by the AESO in support of AUC Rule 021: *Settlement System Code Rules* (Rule 021).[1172]

953. In its rebuttal evidence, ATCO Electric explained its engineering processes and the difficulty in isolating changes related to the reduction in line losses:

> ATCO Electric is not proposing to introduce a line loss module as it is unable to distinguish investments required to maintain the optimal operation of its distribution system from those that may provide a benefit to its line loss, which is a consequence of all the actions ATCO Electric undertakes. As the distribution network expands, ATCO Electric will continue to implement and deliver the appropriate types of distribution investment that considers all important aspects of ensuring a safe and reliable distribution system is in place. Failure of its duty will result in power quality and reliability degradation that will impact ATCO Electric's customers' ability to operate and connect to the distribution system. In addition, current Settlement System Code Rules under Rule 021 ensure utilities are aware and comply with specific unaccounted for energy tolerances that are monitored by the AESO.

Commission findings

954. The Commission considers that line losses are currently within acceptable levels. Nonetheless, the Commission has concerns about how PBR may provide incentives that have an adverse impact on line losses.

955. As a part of the consultative process to review and revise AUC Rule 002, the Commission will consider metrics for monitoring line losses and the establishment of targets for ensuring companies maintain their current levels of line loss performance. The Commission is also prepared to consider other approaches that parties may propose.

[1169] Exhibit 299.02, Cronin and Motluk UCA evidence, PDF pages 184-185.
[1170] Exhibit 636.01, CCA argument, paragraph 360.
[1171] Exhibit 644.01, Fortis reply argument, paragraph 178.
[1172] Exhibit 646.02, EPCOR reply argument, paragraphs 268-270.

14.4 Re-openers for failure to meet service quality targets

956. The UCA, the CCA, IPCAA and EPCOR each proposed that a re-opening of the PBR plan should be undertaken in the event that there is a dramatic decline in service quality.

957. In argument, both the UCA and the CCA recommended that failure to meet a specific performance standard for two consecutive years would be an issue that could trigger a re-opener.[1173] In the case of the CCA, the re-opener would be automatic or "alternatively at the request of an interested party or the AUC."[1174] IPCAA considered that if "customer service is materially degraded by any utility, the PBR plan should be re-opened or even terminated by an off-ramp."[1175] EPCOR's submission included a re-opener for failure to meet the same service quality target for two consecutive years and stated that adjustments to the PBR plan "could include such things as a change to the performance target, a change to the performance measure, or the termination of the measure."[1176]

958. Conversely, ATCO Gas and ATCO Electric were of the opinion that a re-opener clause that is linked to not achieving specific performance standards is not required, especially if service quality is addressed under AUC Rule 002[1177] while Fortis' proposed PBR plan did not include any provisions for re-openers or off-ramps as a result of service quality degradation.[1178]

Commission findings

959. The Commission has the ability under both the *Electric Utilities Act* and the *Gas Utilities Act* to make rules regarding service quality and to monitor and enforce those rules. If it should become apparent that the ways in which the companies are implementing their PBR plans are having a detrimental impact on service quality performance, the Commission can take whatever steps are necessary under the legislation to direct a change in behaviour without having to re-open the PBR plan. Accordingly, the Commission does not accept the proposal to include degradation in service quality as an event that would necessitate a re-opening of the PBR plans.

15 Annual filing requirements

960. The companies recognized a requirement for periodic filings to deal with various rate or capital factor applications during the PBR term. The proposals differed with respect to the number, content and frequency of applications. The companies were also in favour of maintaining existing application processes in respect of certain deferral accounts and flow-through accounts. In addition, some sections of this decision refer to PBR related annual filings under AUC Rule 002 and AUC Rule 005.

15.1 Annual PBR rate adjustment filing

961. Companies generally preferred an annual filing for the setting of the following year's rates. Some of the companies requested a second annual filing with respect to the true-up of

[1173] Exhibit 634.01, UCA argument, paragraph 321; Exhibit 636.01, CCA argument, paragraph 326.
[1174] Exhibit 636.01, CCA argument, paragraph 327.
[1175] Exhibit 635.01, IPCAA argument, paragraph 38.
[1176] Exhibit 103.02, EPCOR submission, paragraph 243.
[1177] Exhibit 648.02, ATCO Gas reply argument, paragraph 432; Exhibit 647.01, ATCO Electric reply argument, paragraph 278.
[1178] Exhibit 633.01, Fortis argument, paragraphs 221-233.

certain factors or amounts that would be included on a forecast basis in the annual rate application so as to adjust rates more than once each year. The Commission has determined above that a second rate adjustment adds unnecessary administrative complexity and is not required.

962. The Commission determines that the effective date for annual rate changes will be January 1st each year. In order to accommodate this date, a number of items will need to be considered leading up to the annual rate change. The annual PBR rate adjustment filing to establish the rates to be in effect on January 1st of the upcoming year is to be made by September 10th of each year.

963. The annual PBR rate adjustment filings for electric distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$R_t = \underbrace{BR_{t-1}(1 + (I - X))}_{\substack{\text{Base rates} \\ (BR_t)}} \pm Z \pm K \pm Y$$

964. The annual PBR rate adjustment filings for gas distribution companies will calculate rates to be effective on January 1st of the upcoming year based on the following:

$$RPC_t = \underbrace{BRPC_{t-1}(1 + (I - X))}_{\substack{\text{Base revenue} \\ \text{per customer class}}} \pm Z \pm K \pm Y$$

$$R_t = RPC_t / BDC_t$$

Where:

R_t	=	upcoming year's rates for each class
RPC_t	=	upcoming year's revenue per customer for each class
BR_{t-1}	=	current year's base rates for each class
$BRPC_{t-1}$	=	current year's base revenue per customer for each class
BDC_t	=	billing determinants for each class for the upcoming year
I	=	inflation factor
X	=	productivity factor
Z	=	exogenous adjustments
Y	=	flow-through items, collected through Y factor rate adjustments (not including Y factors collected through separate riders)
K	=	capital trackers collected through K factor rate adjustments

965. The items to be included in the annual PBR rate adjustment filings will therefore be:

- base rates from the current year by rate class that will be the starting point for the upcoming year's rates
- I factor calculation as described in Section 15.1.1 with supporting backup

- Z factors approved during the previous 12 months calculated as described in Section 15.1.2
- K factor adjustment related to approved capital trackers calculated as described in Section 15.1.3
- Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate items that are not subject to the I-X mechanism to rate classes as described in Section 15.1.5
- backup showing the application of the formula by rate class and resulting rate schedules
- a copy of the Rule 005 filing filed in the current year
- any other material relevant to the establishment of current year rates

15.1.1 I factor

966. As discussed in Section 5.4, the I factor to be included in the annual PBR rate adjustment filings will be calculated using the Alberta AWE (average weekly earnings) from July of the prior year to June of the current year and the Alberta CPI (consumer price index) from July of the prior year to June of the current year. The companies will be required to provide Statistics Canada data for each index and show how the I factor was calculated.

15.1.2 Z factors

967. As noted in Section 7.2.2 some approved Z factor applications may generate costs or savings that can be fully recovered or refunded over a single year or portion thereof while other events will generate costs or savings requiring treatment over a longer term. The nature of the required Z factor rate adjustment will be considered by the Commission on a case-by-case basis in response to a Z factor application.

968. Where a Z factor adjustment has been directed to be included in rates as an adjustment to base rates, the company will make the required adjustment and provide details of the calculation as part of the annual PBR rate adjustment filing.

969. Where a Z factor adjustment has been directed to be included in rates but not as an adjustment to base rates and therefore outside of the I-X mechanism, each company will calculate a Z factor amount to be included in the annual PBR rate adjustment filing. All these Z factor amounts approved by the Commission since the last annual PBR rate adjustment filing will be aggregated as a single rate adjustment and included with the rate adjustment in the next annual PBR rate adjustment filing.

970. Parties should be aware of the Commission's performance standards for processing rate-related applications as prescribed by Bulletin 2010-16.[1179]

971. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Z factor rate adjustments associated with the Z factor revenue requirements by rate class.

[1179] AUC Bulletin 2010-16, Performance Standards for Processing Rate-Related Applications, Table 1.

972. Due to the time lag that may occur between the occurrence of a Z factor event and implementation of the necessary rate adjustments, the companies will be permitted to record carrying charges calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest. This interest rate is consistent with AUC Rule 023,[1180] however the regulatory lag and materiality requirements of Rule 023 will not apply.

15.1.3 Capital trackers

973. The complexity of capital tracker applications will require that these applications be submitted earlier. To promote regulatory efficiency the Commission considers that a single annual capital tracker application filing for each company will be made by March 1st each year.

974. A single application must be filed by March 1st of the current year with respect to all projects which may qualify for capital tracker treatment to be commenced in the upcoming year. The timing of the application is intended to provide sufficient time for processing of the application and inclusion of approved amounts as a K factor in the September 10th annual PBR rate adjustment filing. All of the capital trackers for each company will be collected in a pool that comprises a single K factor in the PBR formula for the company. As discussed in Section 7.3.3.2, the process for filing upcoming projects and associated K factor amounts is only to establish interim K factor rate adjustments. Interim amounts will be subject to true-up to actual costs as part of a prudence review following completion of the project.

975. The annual March 1st capital tracker filing must include a business case with respect to each proposed capital tracker. The business case will include forecast costs, being the amount proposed to be collected on an interim basis through the K factor in the upcoming year. If a project is expected to carry into future years, forecasts for the future years should also be included in order to assess the scope and scale of the project including the materiality of the entire project to be considered. Multi-year forecasts will be updated each year in the capital tracker application so that the forecast amounts to be included that year's K factor will reflect the most recent information available. In addition, the March 1st capital tracker application shall true-up the costs of projects that have been completed since the prior year's capital tracker filing together with sufficient information to permit a prudence review of these completed projects. To facilitate a prudence review of a project, the company must submit information showing that it has completed the project in the most cost effective manner possible. This information will include the results of competitive bidding processes, comparisons of in-house resources to external resources, and any other evidence that may be of assistance in demonstrating the prudence of the expenditures.

976. The results of the prudence review and cost true-up will be an adjustment to the K factor included in the following year's rates. The companies will calculate the revenue requirements resulting from the actual capital tracker expenditures, and compare those to the forecast amounts that were collected on an interim basis in the prior year. The difference between the approved revenue requirements and the forecast revenue requirements for the prior year will form the basis for the K factor true-up rate adjustment. In addition, because the capital expenditures will remain in the tracker for the duration of the PBR term, the amounts to include in the capital tracker revenue requirement calculations in subsequent years during the PBR term will be based on the actual approved expenditures rather than the initial forecasts.

[1180] AUC Rule 023: *Rules Respecting Payment of Interest* (Rule 023), Section 3, paragraph 2, page 2.

977. The calculation of the K factor rate adjustments will be similar to revenue requirement calculations under cost of service, except that the calculation will be limited to the depreciation, taxes and return associated with the incremental rate base for the expenditures that form the capital tracker. The weighted average cost of capital rate to be used in calculating the revenue requirements associated with capital trackers will be based on current rates established in the most recent GCOC proceeding rather than using the rates that were in place at the start of the PBR term. The most recent forecast of billing determinant information along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the K factor rate adjustments associated with revenue requirements by rate class.

978. As discussed in Section 7.3.4, the companies may file, as separate applications at the time of their compliance filing on November 2, 2012, applications for approval of specific 2013 projects as capital trackers, including projects that were included in their PBR filings. The companies need not re-file the information already on the record of this proceeding with respect to those capital projects included in their PBR filings. The companies may specifically refer to the record of this proceeding and supplement that information with additional information or explanations to address the Commission's capital tracker criteria.

15.1.4 Y factor rate adjustments

979. The forecasts for the provision for each Y factor item to be included in the upcoming year's rates will be included in the annual PBR rate adjustment filing. As discussed in Section 7.4.4 the provisions will generally be based on the 2012 test year of the general tariff application or general rate application proceeding that forms the going-in rates. The true-up of the Y factor accounts, being the difference between the prior year provision and the prior year actual result, will also be identified in the September 10th PBR annual filing.

980. For any Commission directed items (e.g., AUC assessment fees, intervener portion of hearing costs, etc.) and the UCA assessment fees, the basis for determining the true-up to be included in the annual PBR rate adjustment filing will be the actual amounts that were incurred from August 1 of the prior year to July 31 of the current year.

981. The true-up process will also capture the impact of any Commission directed items that occurred from September 1 of the prior year to August 31 of the current year that were new and for which there was no provision in the Y factor for the current year.

982. All of the Y factor accounts that are not subject to flow-through treatment and collected by way of a separate rate rider will be collected in a pool that comprises a single Y factor in the PBR formula for the company. The most recent forecast of billing determinants along with the Phase II methodologies in place, as discussed in Section 15.1.5 below, will establish the Y factor rate adjustments associated with Y factor revenue requirements by rate class.

983. Carrying charges on balances that are subject to true up will be calculated using an interest rate equal to the Bank of Canada's Bank Rate plus 1½ per cent, subject to any previously approved Commission procedure for awarding interest on accounts that existed prior to implementation of PBR. This interest rate is consistent with AUC Rule 023,[1181] however the regulatory lag and materiality requirements of Rule 023 will not apply.

[1181] AUC Rule 023, Section 3, paragraph 2, page 2.

15.1.4.1 Flow-through items

984. As discussed in Section 7.4.3, flow-through items currently collected by way of separate rider will be collected using the existing methodology and rider mechanism outside of the annual PBR rate adjustment filing process to recognize that these flow-through items are currently processed throughout the year. As a result, applications related to flow-through items may be submitted throughout the year.

15.1.4.2 Clearing balances in deferral accounts that are not permitted to continue under PBR

985. To the extent that the companies had deferral accounts under cost of service regulation that have not been approved to continue under PBR in this decision, the Commission recognizes that the companies may have residual balances in the deferral accounts that need to be disposed of. The Commission determines that the companies will submit an application identifying the outstanding balances as of December 31, 2012 as part of their annual PBR rate adjustment filing for 2013.

15.1.5 Billing determinants and Phase II implications

986. Under PBR, the portion of electric distribution rates subject to the I-X mechanism is not impacted by changes to billing determinants. The portion of gas distribution rates subject to the I-X mechanism is impacted by changes in usage per customer. Rate adjustments outside of the I-X mechanism (Z factors, K factors and Y factors) for both electric and gas distribution companies will involve calculating a total amount of revenue requirement associated with the underlying items, and then allocating that revenue requirement to rate classes to determine the necessary rate adjustments. This will require the use of billing determinants and Phase II rate class allocation methodologies. In addition, a number of the companies identified the possibility of Phase II applications to revise the rate class allocation methodologies that may be required during the PBR term, which would also require the use of billing determinants.

987. Fortis proposed to use to a method consistent with that used in previous cost of service filings to establish its billing determinants under PBR. Fortis provided a forecast of the billing determinants to be used for the entire PBR term, and indicated that it will accept the risk on any variances between forecasts and actual.[1182] Fortis identified the potential for a Phase II application to transition towards 100 per cent revenue-to-cost ratios by rate class, and the billing determinant forecast would be used for this purpose.[1183]

988. ATCO Electric also provided a forecast for billing determinants for the entire PBR term. ATCO Electric followed the same methodology for preparing the billing determinants and load forecasts used in its 2011 to 2012 GTA. In addition, if a Phase II application is determined to be necessary during the PBR term, ATCO Electric proposed to use the billing determinant forecast provided in its PBR application for input into the cost of service and rate design.[1184]

989. EPCOR proposed that billing determinants be reforecast annually using a calculation methodology that relies on readily available historical billing determinants.[1185] EPCOR identified that Phase II rate rebalancing adjustments may be required as a result of the implementation of a

[1182] Exhibit 100.02, Fortis application, Section 2, paragraph 37, page 10.
[1183] Exhibit 100.02, Fortis application, Section 13.2, paragraph 181, pages 50-51.
[1184] Exhibit 98.02, ATCO Electric application, Section 16, paragraphs 290-291, page 16-3.
[1185] Exhibit 103.02, EPCOR application, Section 2.3.7.1, paragraphs 156-158, pages 53-54.

new geographic information system (GIS).[1186] Aside from the aforementioned adjustment from the implementation of GIS, as a result of the characteristics of its PBR plan, EPCOR identified that Phase II applications will no longer be required in the normal course.[1187]

990. ATCO Gas indicated that it would be providing a billing determinants forecast each year. ATCO Gas proposed to use the principles outlined in its Phase II negotiated settlement approved in Decision 2010-291 to determine the rates for each year. ATCO Gas proposed to use the same methodology as long as the negotiated settlement remains in place. In the event that the negotiated settlement is terminated for any reason, ATCO Gas proposed that a new Phase II application be filed, with the expectation that the determination of rates for the remainder of the PBR term would be governed by the outcome of that proceeding.[1188] Calgary supported the Phase II proposal of ATCO Gas.[1189]

991. AltaGas proposed that its billing determinants be reforecast annually in order to capture any declining usage per customer.[1190] AltaGas anticipated filing a Phase II application for its 2013 to 2017 PBR plan that will involve preparation of a revised cost of service study and rate design based on the revenue requirement approved for 2012, and adjusted pursuant to the proposed PBR formula to collect the forecast 2013 revenue cap amount.[1191]

992. The UCA proposed that each utility should be required to file a Phase II application by the end of 2015 or at the latest 2016. The UCA noted that several of the companies are in the process of performing an analysis on cost allocations and that there are also previous Commission directions that are still outstanding, and as a result it will be necessary to realign rates in the middle of the PBR term.[1192] The CCA generally supported the position of the UCA.[1193] IPCAA stated that "[c]ustomers deserve just, fair and reasonable rates, and a Phase II rates review should not be delayed or deferred by PBR."[1194]

Commission findings

993. The Commission considers that billing determinants will have limited use during the PBR term for electric distribution companies because the I-X mechanism results in rate changes that are separated from the costs of the company, therefore there is no revenue requirement that needs to be allocated to rate classes using billing determinants as was the case under cost of service regulation. The revenue-per-customer cap plans approved for the gas distribution utilities will, however, require usage-per-customer forecasts based on current billing determinants to perform the annual customer rates calculations. In addition, both electric and gas distribution companies will be required to allocate items outside of the I-X mechanism including Z factors, K factors and Y factors to rate classes, and those allocations will require billing determinant forecasts and Phase II methodologies.

1186 Exhibit 103.02, EPCOR application, Section 4.3, paragraph 264, page 84.
1187 Exhibit 103.02, EPCOR application, Section 3.0, paragraph 232, page 77.
1188 Exhibit 99.01, ATCO Gas application, Sections 5.1.2-5.1.3, paragraphs 152-153, pages 53-54.
1189 Exhibit 629.01, Calgary argument, Section 18.1, page 71.
1190 Exhibit 110.01, AltaGas application, Section 2.3, paragraph 42, page 11.
1191 Exhibit 110.01, AltaGas application, Section 13.0, paragraph 125, page 40.
1192 Exhibit 634.02, UCA argument, Section 18.1, paragraphs 424-427, pages 75-76.
1193 Exhibit 636.01, CCA argument, Section 18.2, paragraph 385, page 133.
1194 Exhibit 635.01, IPCAA argument, Section 18.1, paragraph 96, page 15.

994. The Commission determines that long-term forecasts of billing determinants as proposed by Fortis and ATCO Electric are not necessary. As identified by Fortis, the use of long-term forecasts introduces forecasting risk into the PBR plan with respect to billing determinants. Because the billing determinants are generally used to allocate items that have been determined to be exceptions to the incentive properties of PBR, the Commission considers that it is necessary to achieve a greater degree of accuracy. The Commission does not consider that the company or its customers should benefit from, or be negatively impacted by, forecasting inaccuracies that may result from using forecasts that extend well into the future. Utilizing a shorter term for the forecasts will reduce the possibility for material forecasting inaccuracies. For this reason the companies will provide a revised forecast of their billing determinants annually as part of the September 10th annual PBR rate adjustment filings. In addition, the companies will provide the billing determinants forecast to be utilized for January 1, 2013 rates as part of their compliance filings to this decision.

995. Companies will be expected to utilize forecasting methodologies that are logical and easy to understand, and in most cases this will involve the continued use of forecasting methodologies utilized prior to PBR. Companies should utilize consistent billing determinant forecasting methodologies during the PBR term unless the Commission orders otherwise. Companies will describe the methodology they plan to use for the duration of the PBR term as part of their compliance filings to this decision.

996. The Commission considers that PBR is unrelated to the requirement to periodically update rates through a Phase II process. However, during the PBR term the companies may file applications for Phase II adjustments to their rate design and cost allocation methodologies and the Commission will make a determination at that time as to whether the adjustments are warranted. For purposes of a cost of service study, the companies shall use the revenue requirement resulting from going-in rates adjusted by the PBR formula (including the I-X mechanism, K factors, Y factors and Z factors) and the latest updated billing determinants.

15.2 AUC Rule 002 and AUC Rule 005 annual filings

997. As discussed in Section 13, annual AUC Rule 005 filings will continue to be filed by the companies on May 1st for electric distribution utilities and May 15th for gas distribution utilities. In addition, a copy of the prior year AUC Rule 005 filings will be included with the September 10th annual PBR rate adjustment filing.

998. As discussed in Section 14.1, the service quality of the companies will continue to be monitored using the AUC Rule 002 process. Annual service quality filing requirements are set out in the provisions of the rule.

15.3 Summary of annual filing dates

999. Below is a summary of the key annual filing dates under the PBR plans.

Table 15-1 Summary of key PBR annual filing requirements

Date	Action
March 1	Submission of capital tracker applications
May 1 or 15	AUC Rule 005 annual filings (May 1 for electric utilities, May 15 for gas utilities)
September 10	Companies to file annual PBR rate adjustment filings
January 1	Effective date for approved rates that are subject to the PBR formula

16 Generic proceedings

1000. During the first PBR term, the Commission will conduct a number of generic proceedings to deal with issues that arose out of the cost of service regulatory regime, some of which are still relevant to the companies under PBR. These proceedings are "generic" because the issues affect more than one company, including issues such as the recognition of debt costs or the treatment of certain income tax expenses. These generic proceedings are intended to make regulation in Alberta, including regulation of those companies that remain under cost of service regulation, more efficient and more predictable.

1001. To the extent that the decisions coming out of these generic proceedings will impact the companies under PBR, prior to the end of the PBR term, the Commission will consider any necessary rate adjustments using the mechanisms set out in Section 15.1.4 of this decision, as matters arise.

1002. The Commission will shortly issue bulletins to commence a proceeding on the generic cost of capital and to either continue Proceeding ID No. 20 with respect to Utility Asset Dispositions or initiate a generic proceeding regarding asset disposition and stranded assets. Additionally, the Commission will initiate other generic proceedings and will seek input from interested parties on additional matters parties may wish to have considered in generic proceedings, the scope of the issues to be considered, and the format for these proceedings. With regard to the latter, the Commission expects that many of these generic proceedings can take the form of consultations.

17 Order

1003. It is hereby ordered that each of AltaGas Utilities Inc., ATCO Electric Ltd., ATCO Gas and Pipelines Ltd., EPCOR Distribution & Transmission Inc. and FortisAlberta Inc. shall file a compliance filing in accordance with the directions set out in this decision by November 2, 2012. The compliance filing shall include proposed distribution rate schedules to be effective January 1, 2013 with supporting documentation including:

- base rates for going-in rates by rate class that will be the starting point for 2013 rates
- I factor calculation as described in Section 15.1.1 with supporting backup
- provision component of the Y factor adjustment to collect Y factors that are not collected through separate riders calculated as described in Section 15.1.4
- billing determinants for each rate class for gas applications
- billing determinants that will be used to allocate Y factor provisions to rate classes
- backup showing the application of the formula by rate class and resulting rate schedules
- any other material relevant to the establishment of current year rates

Dated on September 12, 2012.

The Alberta Utilities Commission

(original signed by)

Willie Grieve, QC
Chair

(original signed by)

Mark Kolesar
Vice-Chair

(original signed by)

Moin A. Yahya
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ATCO Electric Ltd. (ATCO Electric or AE) L. Keough L. E. Smith L. Kizuk D. Werstiuk J. Teasdale V. Porter M. Bayley
AltaLink Management Ltd. J. Piotto T. Kanasoot E. Tadayoni J. Yeo J. Wrigley K. Evans
ATCO Gas (ATCO Gas or AG) L. E. Smith D. Wilson A. Green M. Bayley L. Fink
ATCO Pipelines L. E. Smith E. Jansen S. Mah D. Dunlop B. Jones A. Jukov
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie R. Koizumi J. Coleman C. Martin P. E. Schoech
The City of Calgary (Calgary) D. I. Evanchuk G. Matwichuk
Central Alberta Rural Electrification Association D. Evanchuk P. Bourne
Consumers' Coalition of Alberta (CCA) J. A. Wachowich J. A. Jodoin A. P. Merani

Name of organization (abbreviation) counsel or representative
Direct Energy Marketing Limited S. Puddicombe
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo D. Gerke P. Wong D. Tenney
ENMAX Power Corporation (ENMAX or EPC) D. Emes G. Weismiller K. Hildebrandt J. Schlauch J. Worsick
FortisAlberta Inc. (Fortis or FAI) J. Walsh
Graves Engineering Corporation J. T. Graves
Industrial Gas Consumers Association of Alberta (IGCAA) G. Sproule
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster T. Clarke R. Mikkelsen S. Fulton V. Bellissimo
City of Lethbridge M. Turner O. Lenz
National Economic Research Associates (NERA) J. Cusano L. Aufricht J. Markholm
The City of Red Deer M. Turner L. Gan
South Alta Rural Electrification Association D. Evanchuk B. Bassett

Name of organization (abbreviation) counsel or representative
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary S. Mattuli W. Taylor R. Bell

The Alberta Utilities Commission Commission Panel W. Grieve, QC, Chair M. Kolesar, Vice-Chair M. A. Yahya, Commission Member Commission Staff B. McNulty (Commission counsel) C. Wall (Commission counsel) A. Sabo (Commission counsel) J. Thygesen O. Vasetsky B. Miller L. Ou D. Mitchell K. Schultz D. Ward B. Clarke S. Karim P. Howard J. Olsen B. Whyte W. Frost G. Scotton S. L. Levin, Emeritus Professor of Economics Department of Economics and Finance School of Business Southern Illinois University Edwardsville

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Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) counsel or representative	Witnesses
National Economic Research Associates, Inc (NERA) J. Cusano L. Aufricht	J. Makholm A. Ros
AltaGas Utilities Inc. (AltaGas or AUI) N. J. McKenzie	P. Schoech R. Camfield G. Johnston A. Mantei R. Retnanandan
ATCO Electric Ltd. and ATCO Gas (ATCO) L. Smith, QC K. Illsey	P. Carpenter M. Bayley D. Wilson D. Freedman B. Goy J. Cummings N. Palladino
The City of Calgary (Calgary) D. I. Evanchuk E. W. Dixon	G. Matwichuk H. Johnson
Consumers Coalition of Alberta (CCA) J. Wachowich	M. Lowry
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) J. Liteplo C. Bystrom	Panel 1 (PRB principles and structure) D. Weisman D. Gerke D. Cole J. Elford H. Haag Panel 2 (PBR inflation, productivity and formula issues) D. Ryan D. Gerke J. Baraniecki C. Cicchetti
FortisAlberta Inc. (Fortis or FAI) T. Dalgleish, QC	I. Lorimer P. Delaney M. Stroh J. Frayer
ENMAX Power Corporation (ENMAX or EPC) D. Wood L. Cusano	K. Hildebrandt G. Weismiller R. Lawton

Name of organization (abbreviation) **counsel or representative**	**Witnesses**
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster	R. Cowburn V. Bellissimo R. Mikkelsen
Office of the Utilities Consumer Advocate (UCA) C. R. McCreary N. Parker	F. Cronin S. Motluk R. Bell

The Alberta Utilities Commission Commission Panel W. Grieve, QC, Chair M. Kolesar, Vice-Chair M. A. Yahya, Commission Member Commission Staff B. McNulty (Commission counsel) C. Wall (Commission counsel) A. Sabo (Commission counsel) J. Thygesen O. Vasetsky B. Miller S. L. Levin, Emeritus Professor of Economics Department of Economics and Finance School of Business Southern Illinois University Edwardsville

Appendix 3 – Major procedural steps in rate regulation initiative: performance-based regulation

(return to text)

1. On February 26, 2010, the Commission wrote in a letter (Exhibit 1.01) sent to interested parties that it was "beginning an initiative to reform utility rate regulation in Alberta."

2. The Commission established a roundtable meeting of interested parties, which took place March 25, 2010 in the AUC hearing room in Edmonton. At the roundtable, the distribution companies said they could file PBR proposals by the end of the first quarter of 2011: March 31, 2011.

3. In an April 9, 2010 letter (Exhibit 6.01) to interested parties, the Commission outlined the discussions at the roundtable and notified them it had contracted the Van Horne Institute to organize a PBR workshop May 26 and May 27 in Edmonton.

4. On May 14, 2010, the Commission issued a letter (Exhibit 27.01) to interested parties on the process for development of guiding PBR principles, which the Commission planned to release via AUC bulletin on July 8, 2010. That letter established a process schedule to receive submissions on which specific incentive-based proposals would be evaluated, with initial submissions to be provided by June 10, 2010 and comments on the submissions to be provided by June 17, 2010.

5. The PBR workshop took place in Edmonton on May 26 and May 27, 2010. Material on the legal dimensions and regulatory evolution of PBR were distributed to roundtable participants ahead of the roundtable, on May 20, 2010.

6. On June 15, 2010, AltaGas Utilities Inc. (AltaGas) proposed a one-week extension to the June 17, 2010 deadline. In a letter (Exhibit 53.01) dated June 16, 2010, the Commission agreed to the request and adjusted the date for its PBR bulletin issuance to July 15, 2010.

7. On July 15, 2010, the Commission issued Bulletin 2010-20 (Exhibit 64.01). In that bulletin the Commission stated the five principles that would guide its examination of specific PBR proposals from regulated utilities.

8. In August, 2010, the Commission hired National Economic Research Associates Inc. (NERA) as an independent consultant to conduct a total factor productivity study or studies.

9. In a letter (Exhibit 71.01) to interested parties dated September 8, 2010, the Commission set out the terms of reference for NERA's engagement.

10. In letters (exhibits 76.01 and 78.01) to the Commission dated November 12 and November 25, 2010, respectively, ATCO Gas and ATCO Electric (jointly ATCO), and AltaGas requested extensions to both the previously established date for filing their PBR proposals of March 31, 2011 and the previously established date for implementation of PBR plans of July 1, 2012. Both requested implementation be delayed to January 1, 2013.

11. By correspondence (Exhibit 79.01) to interested parties on December 16, 2010, the Commission agreed to postpone ATCO and AltaGas' PBR plan filing dates to May 31, 2011 and their PBR implementations to January 1, 2013.

12. NERA filed its expert report (Exhibit 80.02) on total factor productivity with the Commission on December 30, 2010.

13. On February 7, 2011, the Consumers Coalition of Alberta (CCA) expressed concerns about the proposed proceeding schedule, including the May 31, 2011 deadline for filing of PBR plans, due to a heavy regulatory agenda (Exhibit 86.02).

14. On March 24, 2011 EPCOR Distribution & Transmission Inc. (EPCOR), AltaGas, FortisAlberta Inc. (Fortis), ATCO Electric and ATCO Gas submitted a joint letter (Exhibit 89.01) to the Commission requesting a further deadline extension.

15. In a letter (Exhibit 90.01) to the parties dated March 29, 2011, the Commission agreed to certain proceeding schedule changes, including proposing the postponement of filing of utility PBR plans to July 22, 2011. In the same letter the Commission proposed a simplified compliance filing process to ensure that PBR plans could be implemented by January 1, 2013.

16. Following responses from parties, the Commission in a letter (Exhibit 94.01) dated April 13, 2011 set a new proceeding schedule, with utility PBR plans to be submitted July 22, 2011 and a hearing scheduled to begin March 5, 2012.

17. On June 1, 2011, the Lieutenant Governor in Council issued an Order in Council, in which it authorizes the Commission:

> (a) to proceed to fix or approve just and reasonable rates, tolls or charges, or schedules of them, that may be charged by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. under section 45 of the Gas Utilities Act
>
> (i) pursuant to an application filed within the period from June 1, 2011 to December 31, 2013 with the Commission by ATCO Gas and Pipelines Ltd. or AltaGas Utilities Inc. pursuant to, or related to the provisions of, section 45 of the Gas Utilities Act, or
>
> (ii) on the Commission's own motion or initiative commenced within the period from June 1, 2011 to December 31, 2013,

and

> (b) to approve any related, ancillary, compliance or subsequent application arising out of an approval granted, or a direction issued, by the Commission pursuant to an application filed under clause (a)(i) or a motion or initiative of the Commission referred to in clause (a)(ii).

18. On July 22, 2011 PBR submissions and applications were filed by each of ATCO Electric, ATCO Gas, Fortis, EPCOR, and AltaGas.

19. Also on July 22, 2011, AltaGas submitted a letter (Exhibit 102.01) to the Commission requesting approval to negotiate its PBR application with its customer groups.

20. On July 26, 2011 the Commission issued a notice of proceeding (Exhibit 105.01), acknowledging the receipt of the PBR applications and soliciting statements of intention to participate (SIPs) from any party not already registered in the proceeding that wished to intervene or participate. The Commission also re-iterated the proceeding schedule it had issued in its letter to parties of April 13, 2011.

21. On August 12, 2011 the Commission wrote to registered parties in regard to AltaGas' request to negotiate a settlement of its PBR application with its customers (Exhibit 112.01). The Commission requested comment from AltaGas on its rationale for the request by August 19, 2011 and comment from other companies and interveners by August 26, 2011. AltaGas was afforded an opportunity to then reply to other companies' and interveners' forthcoming comments by August 30, 2011.

22. On August 25, 2011, the Commission informed proceeding parties by letter (Exhibit 114.01) that it had chosen to expand the role of NERA "to undertake the preparation of a second report to provide parties and the Commission with an independent, expert critical analysis and evaluation of the material aspects of the utility applications and intervener evidence in Proceeding ID No. 566."

23. On August 31, 2011, the Commission began Round 1 of information requests (IRs) related to the proceeding with questions circulated to all of the companies registered as parties and to NERA.

24. On September 30, 2011 in correspondence (Exhibit 181.01) to all parties, the Commission denied AltaGas' request to negotiate a settlement of its PBR application with its customers.

25. On the same day, ATCO Electric filed a letter (Exhibit 182.01) with the Commission objecting to the IRs filed by The City of Calgary (Calgary) directed to ATCO Electric and to Dr. Carpenter relating to the ATCO Electric application.

26. By letter (Exhibit 183.01) dated October 3, 2011, the Commission requested Calgary's comments on the ATCO Electric objection by October 5, 2011 and ATCO Electric's reply by October 6, 2011.

27. In its letter (Exhibit 186.01) to the parties dated October 11, 2011, the Commission allowed the Calgary IRs to stand and directed ATCO Electric and Dr. Carpenter to answer the IRs.

28. On November 9 and November 10, 2011, the Commission received several motions from each of the UCA, Calgary, and the CCA, requesting for full, responsive and adequate answers to certain IRs from the NERA, AltaGas, Fortis, EPCOR, Dr. Carpenter, and ATCO.

29. The Commission established a process by letter (Exhibit 263.01) dated November 10, 2011, to deal with the motions, which requested NERA and each of the companies or their experts to respond to the motions on November 16, 2011, and concluded with reply comments from the UCA, the CCA and Calgary on November 18, 2011.

30. On November 23, 2011, the Commission wrote to registered parties and provided its rulings on each of the individual motion items (Exhibit 282). In the same letter the Commission set a revised proceeding schedule, with intervener evidence to be submitted December 16, 2011 and a hearing scheduled to begin April 16, 2012.

31. On January 16 and 26, 2012, the Commission issued Round 2 and Round 3 of IRs.

32. On February 22, 2012, NERA filed its second report (Exhibit 391.02): *Update, reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative*.

33. Also on February 22, 2012, ATCO Electric and ATCO Gas filed updates (exhibits 389 and 390) to their respective PBR applications.

34. In a letter (Exhibit 392.01) to registered parties dated February 24, 2012, the Commission provided for a further evidentiary process to allow for information requests, responses and supplemental intervener evidence with respect to ATCO's application updates.

35. On February 29, 2012, the UCA filed a letter (Exhibit 395.01) objecting to the application update filed by ATCO Gas on various grounds and requesting the Commission to undertake certain steps, including the striking of portions of that evidence from the record of the proceeding.

36. On March 1, 2012, the Commission issued a letter (Exhibit 399.01) indicating that it would treat the UCA letter as a motion requiring a Commission decision following a reply to the ATCO response by the UCA not later than March 5, 2012.

37. On March 7, 2012 in correspondence (Exhibit 416.01) to the parties, the Commission permitted the amendment of the ATCO application updates and denied the UCA motion.

38. Also on March 7, 2012, the Commission began Round 4 of IRs in regard to NERA second report.

39. On March 8, 2012, the Commission issued Round 5 of IRs to ATCO in respect of its application updates.

40. By letter (Exhibit 470.01) dated April 4, 2012, the Commission advised parties of the details of oral hearing scheduled to commence April 16, 2012.

41. On April 12 and 13, 2012, the Commission issued Round 6 and Round 7 of IRs.

42. An oral hearing was held in the Commission's Calgary hearing room from April 16, 2012 to May 8, 2012. At the close of the hearing, the Commission directed parties to submit argument by June 8, 2012, and reply argument by July 6, 2012.

43. On June 5, 2012, multiple parties requested an extension of the deadline for filing argument from June 8, 2012 to June 13, 2012. In a letter (Exhibit 627.01) dated June 7, 2012, the Commission agreed to the request and adjusted the date for filing reply argument to July 11, 2012.

44. On July 6, 2012, ATCO proposed a two-day extension to the July 11, 2012 deadline. By letter (Exhibit 640.01) issued on the same day, the Commission agreed to postpone reply argument filing dates to July 13, 2012 for all parties.

45. On July 13, reply argument was received.

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Appendix 4 – Abbreviations

Abbreviation	Name in full
AESO	Alberta Electric System Operator
AG	ATCO Gas
AHE	average hourly earnings
AltaGas or AUI	AltaGas Utilities Inc.
AMR	automated meter reading
ATCO	ATCO Electric and ATCO Gas
ATCO Electric or AE	ATCO Electric Ltd.
AWE	average weekly earnings
CAIDI	customer average interruption duration index
capex	capital expenditures
Calgary	The City of Calgary
CCA	Consumers' Coalition of Alberta
CPI	consumer price index
CSLS	Center for the Study of Living Standards
DSM	demand side management
ECM	efficiency carry-over mechanism
ENMAX or EPC	ENMAX Power Corporation
EPCOR or EDTI	EPCOR Distribution & Transmission Inc.
ESM	earnings sharing mechanism
EUCPI	electric utility construction price index
FBR	formula-based ratemaking
FERC	Federal Energy Regulatory Commission
Fortis or FAI	FortisAlberta Inc.
G&A	general and administrative expenses
GCOC or GCC	generic cost of capital
GDP-IPI	gross domestic product implicit price index
GDP-IPI-FDD	gross domestic product implicit price index for final domestic demand
G factor	growth factor
GRA	general rate application
GTA	general tariff application
I factor	inflation factor
IPCAA	Industrial Power Consumers Association of Alberta
IR	information request

Abbreviation	Name in full
KFEI	K factor efficiency incentive
kWh	kilowatt hours
LBDA	load balancing deferral account
LDC	local distribution company
MFP	multifactor productivity
MIL	maximum investment levels
MP factor	major projects factor
NAICS	North American Industry Classification System
NERA	National Economic Research Associates Inc.
NGSSC	Natural Gas System Settlement Code
O&M	operating and maintenance
PBR	performance-based regulation
PEG	Pacific Economics Group
PFAM	post-final adjustment mechanism
PFP	partial productivity factor
ROE	return on equity
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SAS	(transmission) system access service
SQR	service quality regulation
TAC	transmission access charge
TFO	transmission facility owner
TFP	total factor productivity
TRIF	total recordable injury frequency rate
UCA	Office of the Utilities Consumer Advocate
UMR	urban mains replacement
USA/MFR	uniform system of accounts/minimum filing requirements
WDA	weather deferral account
X factor	productivity factor
Z factor	exogenous factor

Appendix 5 – Company descriptions

AltaGas Utilities Inc.

AltaGas Utilities Inc. is a Leduc-based provider of natural gas distribution services in more than 90 Alberta communities.[1195]

The company operates 20,000 line km of gas distribution pipelines serving more than 72,000 residential, rural and commercial customers in Alberta and employs 200 people. The company's roots stretch back to 1947 and operations in the Athabasca, St. Paul and Leduc areas. Today the company serves communities that also include Barrhead, Bonneyville, Drumheller, Hanna, Three Hills, Grande Cache, High Level, Morinville, Pincher Creek, Dunmore, Stettler, Two Hills, Elk Point and Westlock.

AltaGas Utilities also offers natural gas service for customers with annual load requirements of more than 20,000 gigajoules anywhere in Alberta, an alternative to communities that have existing natural gas service from another supplier, and provides natural gas service proposals to communities that do not currently have natural gas service.

AltaGas Utilities is a unit of AltaGas Ltd., a Calgary-based energy infrastructure company that among other things also operates natural gas utilities in British Columbia, Nova Scotia and has a one-third interest in a Northwest Territories utility. Together, the natural gas utility firms serve 115,000 customers.

1195 All information in this summary was derived from company filings and the AltaGas Utilities (http://www.altagasutilities.com/) and AltaGas Ltd. (http://www.altagas.ca/) websites, accessed on August 16, 2012.

ATCO Electric Ltd.

ATCO Electric Ltd. is an Edmonton-based developer and operator of regulated electricity distribution and transmission infrastructure.[1196] In Alberta, the company operates in the northern and east-central regions of the province through 38 offices in its service area, which covers 245 Alberta communities and includes almost 213,000 customers. It has two divisions: capital projects and operations, with capital projects overseeing construction of major transmission projects and operations overseeing construction of large distribution projects and the management and operation of the company's existing transmission, distribution and technology assets.

Along with larger communities such as Grande Prairie, Fort McMurray, Jasper and Lloydminster, ATCO Electric's service area includes many rural and energy-rich areas of the province and covers the northern half of Alberta, an area west and north of Lloydminster and an area east of Calgary. This is about two-thirds of the geographic area of Alberta.

The company is a unit of publicly-listed ATCO Ltd. through ATCO Ltd. affiliates Canadian Utilities Ltd. and CU Inc. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd. Along with its core operations in Alberta, which stretch back 85 years, ATCO Electric also operates in the Canadian north, principally the Yukon and the Northwest Territories, through subsidiaries Yukon Electrical Company Limited, Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited.

ATCO Electric has an employee count of more than 2,000 people and operates approximately 10,000 km of transmission lines and 62,000 km of distribution lines. The company also operates roughly 10,000 km of distribution lines on behalf of 24 rural electrification associations (REAs) that are within its service territory. In fiscal 2011, the members of six REAs voted to sell their electric system assets to ATCO Electric. In the same year, the company experienced what it described as large-scale growth in transmission development and a similar level of distribution growth related to distribution extension and construction.

Major projects in fiscal 2011 included work on the proposed Eastern Alberta Transmission Line, which is the subject of an application currently before the AUC; the Hanna region transmission development project; and the northeast transmission development projects in the Fort McMurray area. Internally, the company was focused on customer service; operational excellence, talent attraction, development and retention and responding to a changing regulatory environment. The latter work centred around the AUC's Rate Regulation Initiative on Performance-Based Regulation.

[1196] All information in this summary is derived from the ATCO Ltd. 2011 annual report and the ATCO Ltd. (http://www.atco.com/),Canadian Utilities Ltd. (http://www.canadianutilities.com/) and ATCO Electric (http://www.atcoelectric.com/default.asp) websites accessed on August 16, 2012.

ATCO Gas

ATCO Gas is an Edmonton-based distributor of natural gas with more than one million customers in about 300 communities throughout Alberta.[1197] It operates approximately 38,000 km of distribution pipes and employs about 2,000 Albertans at its headquarters and across its province-wide network of more than 60 district offices.

The company is celebrating its 100th anniversary of founding in 2012. The roots of the company go back to the origins of natural gas service in the province of Alberta in 1912 with Canadian Western Natural Gas in southern Alberta and the Calgary area, and Northwestern Utilities Limited in northern Alberta and the Edmonton area in 1923.

Along with natural gas distribution, ATCO Gas provides expert advice to consumers through ATCO EnergySense and the ATCO Blue Flame Kitchen. It is the largest natural gas distribution utility in Alberta and serves municipal, residential, business and industrial customers.

The company is a division of ATCO Gas and Pipelines Ltd., which is in turn part of the publicly-listed ATCO Ltd. corporate group. ATCO Ltd. ATCO Ltd. is controlled by ATCO Ltd. Chairman Ron Southern through the Southern family holding company, Sentgraf Ltd.

In 2011 ATCO Gas spent more than $287 million on capital projects it said enhanced system integrity and reliability and ensured public safety.

[1197] All information in this summary is derived from company filings, the ATCO Ltd. 2011 annual report and the ATCO. Ltd. (http://www.atco.com/) and ATCO Gas (http://www.atcogas.com/) websites, accessed on August 16, 2012.

EPCOR Distribution & Transmission Inc.

EPCOR Distribution and Transmission Inc. (EDTI) provides electricity distribution service through aerial and underground distribution lines and related facilities to its service area in the city of Edmonton.[1198]

The company is a wholly owned subsidiary of EPCOR Utilities Inc., a provider of electricity and water services to customers in Canada and the United States, and is owned by the City of Edmonton. Both EDTI and its corporate parent are based in Edmonton. The parent was founded in October 1891 as the Edmonton Electric Lighting and Power Company and became municipally owned in 1902.

EDTI provides electricity distribution services to more than 308,000 residential and 35,000 commercial consumers in Edmonton, distributing roughly 14 per cent of Alberta's electricity consumption. The company operates 72-kV, 138-kV, 240-kV and 500-kV lines and cables. It distributes electricity in Edmonton through a network of eight distribution substations, 287 distribution feeders and approximately 5,000 circuit km of primary distribution lines.

Along with distribution services, EDTI also operates high-voltage substations and high-voltage transmission lines in the Edmonton area, including 203 circuit km of transmission lines and 29 transmission substations. These form part of the Alberta interconnected electric system. EDTI also provides services to the Alberta Electric System Operator, provides the distribution tariff and settlement services in Edmonton for the competitive electric market. It also manages and collects load data in the Edmonton area through meter reading, data collection and management.

The company employs approximately 629 people in its distribution arm and 139 individuals in its transmission operations.

[1198] All information in this summary is derived from company filings and the EPCOR Utilities Inc. website (http://corp.epcor.com/Pages/home.aspx) accessed on August 16, 2012.

FortisAlberta Inc.

FortisAlberta Inc. distributes electricity to nearly half-a-million Albertans living in 200 communities across central and southern Alberta.[1199]

The company's origins are as the distribution arm of TransAlta Corp., which TransAlta sold in 2000, and it operates 115,000 km of power lines across a 225,000-km service area that represents more than 60 per cent of Alberta's low-voltage distribution network.

Based in Calgary, FortisAlberta employs 1,000 people working at its headquarters and 52 service points in its service territory. The company operates a 24-hour outage repair and emergency response capability, builds, maintains and upgrades power lines and facilities, installs and reads electricity meters, provides consumption data to retailers that bill customers and promotes electrical safety in the communities it serves.

FortisAlberta is a subsidiary of publicly-listed Fortis Inc., Canada's largest investor-owned distribution utility and which among other things operates regulated electric utilities in five Canadian provinces and a natural gas utility in British Columbia. Fortis Inc. is based in St. John's, Newfoundland and Labrador and its shares trade on the Toronto Stock Exchange.

[1199] All information in this summary was derived from company filings, AUC records, and the FortisAlberta Inc. (http://www.fortisalberta.com/home.aspx) and Fortis Inc. (http://www.fortisinc.com/) websites, accessed on August 16, 2012.

Appendix E1

SUMMARY OF GENERAL ASSUMPTIONS AND REPORTS

1. GENERAL ASSUMPTIONS

This appendix includes the inflation, tax rate and debt assumptions and supporting information used in this Application. Historic information from 2008 to 2012 has also been provided.

Please refer to Attachment 1 – Summary of General Assumptions page of this appendix for detail information for 2008-2018.

2. INFLATION

2.1 *INTRODUCTION*

The forecast British Columbia CPI is used as a cost driver for aspects of the cost of service because it is widely regarded as a reasonable measure of the forecast inflation applicable to the Province. The CPI is generally used to index wages, salaries, pension, and various other expenses.

2.2 *REVIEW HISTORY HIGHLIGHTS (2008-2012 ACTUALS)*

Pursuant to the provisions of the 2004-2007 and 2008-2009 Settlement Agreements (Order G-51-03 and Order G-33-07), the BC CPI inflation forecast was determined as the average of the forecasts from four reputable industry sources: Conference Board of Canada, B.C. Ministry of Finance, RBC Financial Group, and the Toronto-Dominion Bank. In this Application, FEI has also included forecasts from the Canadian Imperial Bank of Commerce and the Bank of Montreal to provide two more reputable industry sources which will further increase the precision of an average BC CPI inflation forecast. In addition to the forecast CPI, and also in accordance with the Settlement Agreements, an adjustment factor was applied to the BC CPI to arrive at the inflation applied formula operating and maintenance expense and formula capital additions throughout the 2008 – 2009 PBR period. The following table provides a summary of the BC CPI and the adjusted CPI embedded in the revenue requirements from 2008-2012:

Table E1-1: Historic BC CPI and FEI Adjustment Factors (2008-2012)

	2008	2009	2010	2011	2012
CPI	2.20%	2.00%	1.40%	2.30%	1.10%
Adjustment Factor	-1.32%	-1.39%			
Adjusted CPI	0.88%	0.61%	1.40%	2.30%	1.10%

Table E1-2: Summary of Sources and Dates of CPI Forecasts

Source	Forecast Publish Date
Conference Board of Canada	November 2012
B.C. Ministry of Finance	February 2013
RBC Financial Group	April 2013
CIBC	January 2013
Toronto-Dominion Bank	April 2013
BMO	May 2013

3. ATTACHMENTS

The following attachments are included with this appendix:

1. Summary of General Assumptions: 2008-2018
2. Conference Board of Canada CPI report
3. B.C. Ministry of Finance CPI report
4. Royal Bank of Canada CPI report
5. Canadian Imperial Bank of Commerce CPI report
6. Toronto Dominion Bank CPI report
7. BMO CPI report
8. Bank of Nova Scotia short-term interest rates
9. Toronto Dominion Bank short-term interest rates
10. Canadian Imperial Bank of Commerce short-term interest rates
11. Royal Bank of Canada short-term interest rates
12. BMO short-term interest rates
13. National Bank Financial short-term interest rates

FEI

Line No.			2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2012 Approved	Variance	2013 Projected	2013 Approved	Variance	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	B.C. Inflation (CPI):	Conference Board of Canada						2.16%			2.00%		1.90%	2.10%	2.00%	2.10%	2.10%
		BMO											1.70%	2.00%	2.00%	2.00%	2.00%
2		B.C. Ministry of Finance						2.00%			2.10%		2.00%	2.10%	2.10%	2.10%	N/A
3		RBC Financial Group						1.80%			N/A		1.60%	N/A	N/A	N/A	N/A
4		Toronto Dominion Bank						2.00%			2.00%		2.00%	N/A	N/A	N/A	N/A
5		CIBC											1.80%	N/A	N/A	N/A	N/A
6																	
7		Average CPI	2.20%	2.00%	1.40%	2.30%	1.10%	2.00%	-0.90%	0.93%	2.00%	1.07%	1.83%	2.07%	2.03%	2.07%	2.05%
8																	
9	AWE Labour Inflation																
10		Conference Board of Canada			2.80%	1.50%	2.30%			2.30%			2.70%	2.70%	2.60%	2.60%	2.50%
11																	
12	Labour Split																
13		Labour								55.00%			55.00%	55.00%	55.00%	55.00%	55.00%
14		Non Labour								45.00%			45.00%	45.00%	45.00%	45.00%	45.00%
15																	
16	CPI/AWE												2.31%	2.42%	2.34%	2.36%	2.30%
17																	
18	Productivity Factor									0.50%			0.50%	0.50%	0.50%	0.50%	0.50%
19																	
20	Forecast Service Line Additions									7,992			8,051	8,407	8,555	8,444	8,270
21																	
22	Average Customers									840,721			845,495	850,620	856,001	861,402	866,681
23																	
24	Customer Growth												0.57%	0.61%	0.63%	0.63%	0.61%
25																	
26	Income Tax Rate:	Federal					15.00%	15.00%		15.00%	15.00%		15.00%	15.00%	15.00%	15.00%	15.00%
27		Provincial					10.00%	10.00%		10.00%	10.00%		10.00%	10.00%	10.00%	10.00%	10.00%
28			31.50%	30.00%	28.50%	26.50%	25.00%	25.00%		25.00%	25.00%		25.00%	25.00%	25.00%	25.00%	25.00%
29																	
30	Foreign Exchange Rate:																
31		USD/CAD Exchange Rate	1.06	1.14	1.03	1.02	0.99	1.01	0.02	1.03	1.03	- 0.00	1.01	0.99	1.01	1.04	1.05
32		CAD/USD Exchange Rate	0.94	0.88	0.97	0.98	1.01	0.98	- 0.01	0.97	0.97	-	0.99	1.01	0.99	0.96	0.95
33																	
34	Cost of Capital:																
35		**FEI**															
36		Short Term Debt Interest Rates	5.00%	4.25%	2.25%	4.50%	2.50%	2.50%	-0.25%	1.75%	3.50%	1.75%	1.75%	2.50%	3.25%	3.75%	4.75%
37		Long Term Debt Interest Rates	7.21%	6.96%	6.95%	6.95%	6.85%	5.00%	1.95%	3.05%	5.50%	2.45%	3.80%	4.30%	4.80%	5.05%	5.05%
38		Return on Equity	10.83%	12.05%	9.42%	10.15%	10.12%	9.50%	-0.08%	8.75%	9.50%	0.75%	8.75%	8.75%	8.75%	8.75%	8.75%
39																	
40																	

Table 11—Key Economic Indicators: British Columbia
(forecast completed: November 16, 2012)

	2010	2011	2012f	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f	2021f	2022f
GDP at market prices (current $)	203,163	216,356	223,288	233,906	245,762	258,218	269,753	279,761	291,763	302,489	311,884	322,538	334,226
	5.9	*6.5*	*3.2*	*4.8*	*5.1*	*5.1*	*4.5*	*3.7*	*4.3*	*3.7*	*3.1*	*3.4*	*3.6*
GDP at basic prices (current $)	187,526	200,033	206,178	215,931	226,932	238,567	249,318	258,551	269,787	279,726	288,316	298,138	308,981
	5.9	*6.7*	*3.1*	*4.7*	*5.1*	*5.1*	*4.5*	*3.7*	*4.3*	*3.7*	*3.1*	*3.4*	*3.6*
GDP at basic prices (constant 2002 $)	153,085	157,525	160,368	164,744	169,066	173,541	177,805	181,255	185,627	189,275	192,493	196,022	199,875
	3.2	*2.9*	*1.8*	*2.7*	*2.6*	*2.6*	*2.5*	*1.9*	*2.4*	*2.0*	*1.7*	*1.8*	*2.0*
Consumer Price Index (2002 = 1.0)	1.138	1.165	1.181	1.197	1.220	1.245	1.271	1.297	1.324	1.352	1.380	1.409	1.438
	1.4	*2.3*	*1.4*	*1.3*	*1.9*	*2.1*	*2.0*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*	*2.1*
Implicit price deflator— GDP at basic prices (2002 = 1.0)	1.225	1.270	1.286	1.311	1.342	1.375	1.402	1.426	1.453	1.478	1.498	1.521	1.546
	2.6	*3.7*	*1.2*	*1.9*	*2.4*	*2.4*	*2.0*	*1.7*	*1.9*	*1.7*	*1.3*	*1.5*	*1.6*
Average weekly wages (level $, industrial composite)	796	808	826	845	868	891	914	938	962	987	1013	1040	1066
	2.8	*1.5*	*2.3*	*2.3*	*2.7*	*2.7*	*2.6*	*2.6*	*2.5*	*2.6*	*2.7*	*2.6*	*2.6*
Personal income (current $)	163,959	171,141	177,041	183,855	191,989	200,342	208,350	216,450	224,347	232,686	241,397	250,358	259,506
	4.0	*4.4*	*3.4*	*3.8*	*4.4*	*4.4*	*4.0*	*3.9*	*3.6*	*3.7*	*3.7*	*3.7*	*3.7*
Personal disposable income (current $)	132,170	136,813	140,688	145,321	151,139	157,390	163,408	169,536	175,473	181,947	188,659	195,554	202,417
	4.8	*3.5*	*2.8*	*3.3*	*4.0*	*4.1*	*3.8*	*3.8*	*3.5*	*3.7*	*3.7*	*3.7*	*3.5*
Personal savings rate	–3.3	–4.0	–5.1	–6.0	–6.3	–6.2	–5.9	–5.9	–6.0	–6.1	–6.2	–6.2	–6.3
Population (000s)	4,523	4,572	4,617	4,670	4,727	4,786	4,846	4,907	4,968	5,029	5,091	5,151	5,212
	1.6	*1.1*	*1.0*	*1.1*	*1.2*	*1.2*	*1.3*	*1.3*	*1.2*	*1.2*	*1.2*	*1.2*	*1.2*
Labour force (000s)	2,442	2,458	2,487	2,522	2,554	2,581	2,603	2,626	2,644	2,662	2,680	2,697	2,714
	1.6	*0.7*	*1.2*	*1.4*	*1.3*	*1.1*	*0.9*	*0.9*	*0.7*	*0.7*	*0.7*	*0.6*	*0.6*
Employment (000s)	2,257	2,275	2,317	2,349	2,399	2,440	2,468	2,494	2,512	2,530	2,546	2,563	2,579
	1.7	*0.8*	*1.8*	*1.4*	*2.1*	*1.7*	*1.2*	*1.0*	*0.8*	*0.7*	*0.6*	*0.6*	*0.6*
Unemployment rate (percentage)	7.6	7.5	6.9	6.9	6.1	5.5	5.2	5.0	5.0	5.0	5.0	5.0	5.0
Retail sales (current $)	58,220	60,005	61,312	62,960	65,627	68,042	70,147	72,388	74,695	77,203	79,773	82,332	84,820
	5.4	*3.1*	*2.2*	*2.7*	*4.2*	*3.7*	*3.1*	*3.2*	*3.2*	*3.4*	*3.3*	*3.2*	*3.0*
Housing starts (units)	26,479	26,400	28,355	27,040	28,000	30,942	32,473	32,265	31,312	30,452	30,132	29,648	29,368
	64.7	*–0.3*	*7.4*	*–4.6*	*3.6*	*10.5*	*4.9*	*–0.6*	*–3.0*	*–2.7*	*–1.1*	*–1.6*	*–0.9*

Shaded area represents forecast data.
All data are in millions of dollars, seasonally adjusted at annual rates, unless otherwise specified.
For each indicator, the first line is the level and the second line is the percentage change from the previous period.
Sources: The Conference Board of Canada; Statistics Canada; CMHC Housing Time Series Database.

Table 3.6.3 Components of Nominal Income and Expenditure

	2011	2012	Forecast 2013	2014	2015	2016	2017
Labour income[1] ($ million)	109,741 [2]	113,801 [e]	118,231	123,155	128,606	134,244	140,118
(% change)	4.9	3.7	3.9	4.2	4.4	4.4	4.4
Personal income ($ million)	171,309 [2]	177,637 [e]	183,736	190,996	199,010	207,280	215,987
(% change)	4.5	3.7	3.4	4.0	4.2	4.2	4.2
Corporate profits before taxes ($ million)	25,132 [2]	25,547 [e]	26,632	28,166	29,981	31,884	33,925
(% change)	16.3	1.7	4.2	5.8	6.4	6.3	6.4
Retail sales ($ million)	60,005	61,612 [e]	63,793	66,371	69,058	71,845	74,738
(% change)	3.1	2.7	3.5	4.0	4.0	4.0	4.0
Housing starts	26,400	27,465	24,679	24,928	27,277	27,698	27,701
(% change)	-0.3	4.0	-10.1	1.0	9.4	1.5	0.0
BC consumer price index (2002 = 100)	116.5	117.8	119.6	122.0	124.6	127.3	130.0
(% change)	2.4	1.1	1.5	2.0	2.1	2.1	2.1

[1] Domestic basis; wages, salaries and supplementary labour income.

[2] Annual 2011 figures for labour income, personal income and corporate profits before taxes are BC Stats estimates. Note that the definitions and concepts of labour income, personal income and corporate profits are based on the definitions and concepts previously used by Statistics Canada and are not consistent with the new definitions and concepts introduced by Statistics Canada in November 2012.

[e] Ministry of Finance estimate.

Table 3.6.4 Labour Market Indicators

	2011	2012	Forecast 2013	2014	2015	2016	2017
Population (on July 1) (000's)	4,577	4,623	4,666	4,718	4,775	4,837	4,901
(% change)	1.0	1.0	0.9	1.1	1.2	1.3	1.3
Labour force population, 15+ Years (000's)	3,779	3,815	3,855	3,901	3,950	4,002	4,054
(% change)	1.3	1.0	1.1	1.2	1.3	1.3	1.3
Net in-migration (000's)							
– International[1,3]	35.4	40.7 [e]	40.0	40.1	43.2	44.6	44.9
– Interprovincial[3]	-0.1	-8.0 [e]	2.0	6.0	9.0	11.0	12.0
– Total	35.2	32.7 [e]	42.0	46.1	52.2	55.6	56.9
Participation rate[2] (%)	65.0	65.0	65.2	65.3	65.4	65.6	65.7
Labour force (000's)	2,458	2,479	2,515	2,548	2,584	2,623	2,663
(% change)	0.6	0.9	1.4	1.3	1.4	1.5	1.5
Employment (000's)	2,275	2,313	2,339	2,369	2,406	2,443	2,479
(% change)	0.8	1.7	1.1	1.3	1.5	1.5	1.5
Unemployment rate (%)	7.5	6.7	7.0	7.0	6.9	6.9	6.9

[1] International migration includes net non-permanent residents and returning emigrants less net temporary residents abroad.

[2] Percentage of the population 15 years of age and over in the labour force.

[3] Components may not sum to total due to rounding.

[e] BC Stats estimate.

British Columbia

		2007	2008	2009	2010	2011	2012	2013F	2014F
Real GDP	Chained $2007 millions	196,997	199,228	194,334	200,550	206,180	209,974	213,228	219,071
	% change		**1.1**	**-2.5**	**3.2**	**2.8**	**1.8**	**1.6**	**2.7**
Employment	thousands	2,223	2,266	2,218	2,257	2,275	2,313	2,335	2,367
	% change	**3.5**	**2.0**	**-2.1**	**1.7**	**0.8**	**1.7**	**1.0**	**1.4**
Unemployment rate	%	4.3	4.6	7.7	7.6	7.5	6.7	6.3	6.3
Retail sales	$ millions	56,930	57,783	55,222	58,220	60,005	61,323	63,126	65,610
	% change	**7.1**	**1.5**	**-4.4**	**5.4**	**3.1**	**2.2**	**2.9**	**3.9**
Housing starts	units	39,195	34,321	16,077	26,479	26,400	27,500	23,900	23,500
	% change	**7.6**	**-12.4**	**-53.2**	**64.7**	**-0.3**	**4.2**	**-13.1**	**-1.7**
Consumer price index	2002=100	110.0	112.3	112.3	113.8	116.5	117.8	118.6	120.5
	% change	**1.7**	**2.1**	**0.0**	**1.4**	**2.3**	**1.1**	**0.7**	**1.6**

Alberta

		2007	2008	2009	2010	2011	2012	2013F	2014F
Real GDP	Chained $2007 millions	258,850	262,864	251,286	261,457	274,717	285,431	293,851	306,310
	% change		**1.6**	**-4.4**	**4.0**	**5.1**	**3.9**	**3.0**	**4.2**
Employment	thousands	1,991	2,054	2,025	2,017	2,094	2,150	2,205	2,248
	% change	**3.9**	**3.1**	**-1.4**	**-0.4**	**3.8**	**2.6**	**2.6**	**1.9**
Unemployment rate	%	3.5	3.6	6.6	6.5	5.5	4.6	4.4	4.5
Retail sales	$ millions	61,487	61,614	56,478	59,849	64,004	68,839	72,488	76,283
	% change	**9.9**	**0.2**	**-8.3**	**6.0**	**6.9**	**7.6**	**5.3**	**5.2**
Housing starts	units	48,336	29,164	20,298	27,088	25,704	33,300	33,000	32,000
	% change	**-1.3**	**-39.7**	**-30.4**	**33.5**	**-5.1**	**29.6**	**-0.9**	**-3.0**
Consumer price index	2002=100	117.9	121.6	121.5	122.7	125.7	127.1	129.1	131.2
	% change	**4.9**	**3.2**	**-0.1**	**1.0**	**2.4**	**1.1**	**1.6**	**1.7**

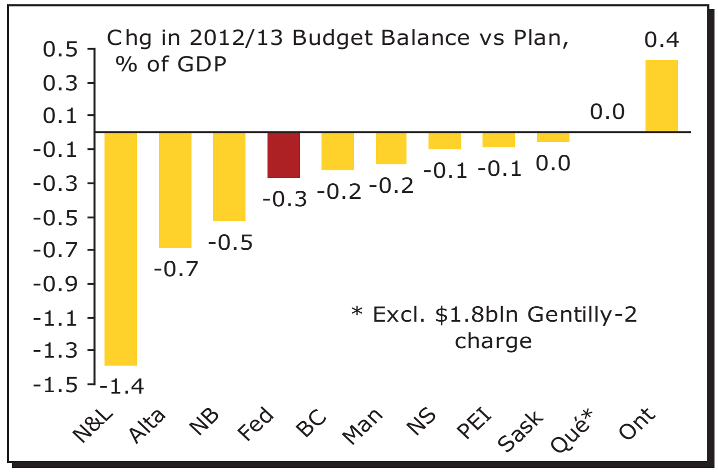
Saskatchewan

		2007	2008	2009	2010	2011	2012	2013F	2014F
Real GDP	Chained $2007 millions	51,964	54,776	52,567	54,854	57,536	58,917	60,596	62,862
	% change		**5.4**	**-4.0**	**4.4**	**4.9**	**2.4**	**2.9**	**3.7**
Employment	thousands	504	513	519	524	526	537	552	561
	% change	**2.4**	**1.7**	**1.3**	**0.9**	**0.3**	**2.1**	**2.7**	**1.6**
Unemployment rate	%	4.2	4.1	4.8	5.2	5.0	4.7	4.3	4.3
Retail sales	$ millions	13,129	14,673	14,598	15,101	16,234	17,317	18,246	19,141
	% change	**13.6**	**11.8**	**-0.5**	**3.4**	**7.5**	**6.7**	**5.4**	**4.9**
Housing starts	units	6,007	6,828	3,866	5,907	7,031	10,000	7,900	6,900
	% change	**61.7**	**13.7**	**-43.4**	**52.8**	**19.0**	**42.2**	**-21.0**	**-12.7**
Consumer price index	2002=100	112.2	115.9	117.1	118.7	122.0	123.9	126.6	129.8
	% change	**2.9**	**3.2**	**1.1**	**1.3**	**2.8**	**1.6**	**2.1**	**2.5**

In contrast, nominal GDP growth has been better insulated in Central Canada. Underlying fiscal targets remain intact in Québec (excluding the costs of mothballing a nuclear power plant), while Ontario is poised to narrow its deficit to less than $12 bn in 2012/13. Indeed, Ontario is the sole province positioned to better its 2012/13 fiscal target (Chart 6), in part a nod to the lift provided by a stronger US. Ontario no longer has the largest deficit in the country as a percent of GDP.

Chart 6

Revisions to 2012/13 Budget Plans: Ontario Holding Up Better



Source: CIBC, Provincial governments

In contrast to very real restraint being administered in provinces like Ontario, the ability of lower debt regions to relax timelines for deficit reduction (e.g., in Manitoba) or to bring forward infrastructure outlays (e.g., in Alberta) suggests a less immediate fiscal drag for some. The result is that with lower-debt provinces enjoying less of a growth differential, and less pressed to tighten fiscally, the gaps in deficit-to-GDP performance look to be narrowing.

There are important implications for credit markets, with Ontario's progress on deficit targets putting off the threat of a credit rating downgrade and its relatively stronger fiscal showing meaning that province will account for a smaller share of provincial bond supply ahead. So don't be surprised if Ontario bonds continue to recoup some of the earlier spread widening to other provincial peers, a trend that is already apparent but likely still has some room to run.

Table 2

Detailed Economic Forecast

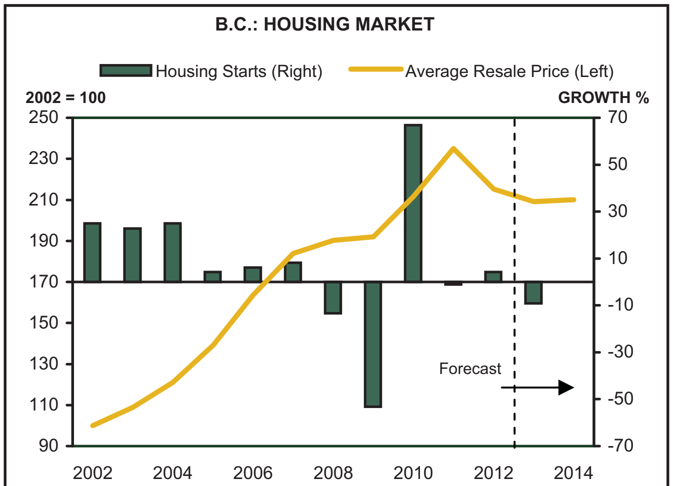
	Real GDP Yr/Yr % Chg			Employment Yr/Yr % Chg			Unemployment Rate %			Housing Starts 000s Units			Consumer Price Index Yr/Yr % Chg		
	2012E	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F
BC	2.1	1.6	2.4	1.7	0.8	1.5	6.8	6.7	6.3	27.5	22.0	21.3	1.1	0.8	1.8
Alta	3.4	2.3	2.8	2.6	1.4	1.5	4.7	4.6	4.6	33.3	31.9	31.0	1.1	1.1	2.4
Sask	3.0	2.4	2.9	2.1	1.8	1.6	4.8	4.6	4.5	10.0	10.0	9.8	1.6	1.3	2.3
Man	2.3	1.8	2.3	0.9	1.4	1.3	5.3	5.3	5.1	7.4	6.4	6.1	1.6	1.7	2.1
Ont	2.0	1.8	2.5	0.8	1.7	1.6	7.9	7.8	7.4	77.0	63.0	62.3	1.4	1.4	2.2
Qué	1.0	1.3	2.0	0.7	1.4	1.1	7.8	7.6	7.4	47.2	42.0	41.6	2.1	1.7	1.8
NB	0.8	1.3	1.8	-0.1	0.0	0.8	10.3	10.5	10.0	3.3	3.0	2.9	1.7	1.4	1.7
NS	1.4	1.7	2.3	0.7	0.5	1.2	9.0	9.0	8.6	4.5	4.6	4.5	1.9	1.5	2.0
PEI	1.5	1.6	1.9	1.0	1.4	1.0	11.3	11.3	11.0	0.9	0.9	0.9	2.0	1.3	1.7
N&L	0.0	4.5	2.0	2.1	2.0	1.5	12.5	11.7	11.4	4.0	3.4	3.3	2.1	1.7	2.3
Cda	**2.0**	**1.7**	**2.4**	**1.1**	**1.4**	**1.4**	**7.3**	**7.2**	**6.8**	**215**	**187**	**184**	**1.5**	**1.3**	**2.1**

Sources: CIBC, Statistics Canada, CMHC

B.C.: GOOD RESOURCE OUTLOOK COUNTERBALANCED AGAINST HOUSING CORRECTION

- Strength in the resource and agricultural sectors will push the British Columbia economy forward over the 2013-14 period, but the housing correction already underway will be an impediment to growth this year.
- Increasing exports to Asia and the U.S. will be instrumental in driving an expansion over the 2013-14 period.

British Columbia is already knee-deep in its housing correction, especially in the Greater Vancouver market where prices and starts had reached unsustainable levels. Existing home sales for the province declined 12% in 2012 and, as of February 2013, currently sit 24% below the level posted a year earlier. Resale prices are also down, falling by 8% in 2012. We expect the market to begin stabilizing later this year, helped by ultra-low interest rates and some rejuvenation in foreign appetite for real estate. Accordingly, we anticipate that declines in sales and prices will moderate this year to 11% and 3% respectively, before turning in a modest rebound in 2014. In the new housing market, a cooling period has already taken place, with current activity now more in line with household formation.



Forecast by TD Economics as of April 2013.
Source: Haver Analytics and TD Economics.

Resource and agricultural sectors: sources of strength

A pick-up in natural gas prices, albeit from still low levels, can be expected in 2013, as increased demand helps draw down inventories in the United States. In addition to higher heating demand due to the recent cold spell, an expected increase in U.S. industrial production will also provide a boost to the natural gas sector in the second half of 2013 and into 2014. Over the longer term, the outlook for natural gas in B.C. is very bright, as a multitude of potential projects have been tabled to get liquified natural gas to port for emerging Asian markets. The recent turnaround in the U.S. housing market has also provided a boost to the B.C. economy, raising demand for softwood lumber. Lumber prices have followed suit, rising by 37% since mid-October, and are now sitting at their highest level since 2004. While prices may pull back somewhat as production increases, they should remain elevated given the still-significant upside potential for U.S. homebuilding.

BRITISH COLUMBIA - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2010	2011	2012E	2013F	2014F
Real GDP	3.2	2.8	2.1	1.6	2.6
Nominal GDP	6.5	4.5	3.4	3.1	4.6
Employment	1.7	0.8	1.7	1.3	1.6
Unemployment rate (%)	7.6	7.5	6.7	6.6	6.5
Consumer Price Index	1.3	2.4	1.1	1.0	2.0
Retail trade	5.4	3.1	2.2	2.4	3.5
Housing starts	66.6	-1.3	4.6	-12.8	-4.2
Existing home sales	-12.2	2.8	-11.8	-11.1	9.0
Avg. existing home price	10.3	11.0	-8.4	-2.8	0.5

E, F: Estimate, Forecast by TD Economics as of April 2013.
Note: For 2012, real and nominal GDP are estimates.
All other indicators are actuals.
Source: Statistics Canada / Haver Analytics

B.C. is not as reliant on the U.S. for its external demand as other provinces. The province is much more diverse in terms of export markets and can rely on the strength of Asian economies to foster economic growth through net trade. Exports to Asian markets accounted for roughly 40% of total international merchandise exports in 2012. Our expectation is that Asian demand for B.C.'s key exports is likely to remain solid as the pace of expansion in that region remains robust.

Fiscal drag and uncertainty the order of the day

With an election set for mid-May, uncertainty reigns supreme, especially in light of the recent 2013 budget. The February 19th budget outlined an aggressive plan to turn a \$1.2 billion deficit into a surplus within one year. Targeted corporate and personal income tax measures, the latter being temporary, combined with expenditure management, are being counted on to help slay the deficit. However, the budget has not received legislative approval and therefore the future of these measures remain unclear.

Provincial Economic Outlook

BMO Capital Markets Economics
May 17, 2013

	Cda	BC	Alta	Sask	Man	Ont	Que	NB	NS	PEI	Nfld
Real GDP Growth (% change, chain-weighted)											
2010	**3.2**	3.2	4.0	4.4	2.5	3.2	2.5	3.1	1.9	2.6	6.3
2011	**2.6**	2.8	5.1	4.9	2.0	1.8	1.9	0.0	0.5	1.6	3.0
2012 e	**1.8**	1.7	3.9	2.2	2.7	1.4	1.0	-0.6	0.2	1.2	-4.8
2013 f	**1.6**	1.7	2.5	2.4	2.0	1.5	1.2	0.9	1.4	1.5	5.0
2014 f	**2.3**	2.5	2.9	2.8	2.3	2.3	1.8	1.6	1.9	1.7	1.8
Employment Growth (% change)											
2010	**1.4**	1.8	-0.4	0.9	1.9	1.6	1.8	-1.0	0.2	3.1	3.5
2011	**1.5**	0.8	3.8	0.3	0.7	1.8	1.0	-1.2	0.0	1.9	2.7
2012	**1.2**	1.6	2.6	2.2	0.9	0.8	0.8	-0.2	0.6	1.0	2.1
2013 f	**1.2**	0.3	1.6	2.2	1.5	1.2	1.4	0.2	0.0	2.2	1.8
2014 f	**1.3**	1.5	1.5	1.2	0.8	1.4	1.2	0.5	1.1	0.2	0.3
Unemployment Rate (percent)											
2010	**8.0**	7.6	6.5	5.2	5.4	8.6	7.9	9.3	9.2	11.3	14.3
2011	**7.5**	7.5	5.5	5.0	5.4	7.8	7.7	9.5	8.8	11.4	12.6
2012	**7.3**	6.8	4.6	4.8	5.3	7.9	7.8	10.3	9.0	11.3	12.5
2013 f	**7.0**	6.5	4.6	4.4	5.1	7.5	7.5	10.5	9.2	11.7	11.8
2014 f	**6.7**	6.3	4.4	4.2	5.0	7.1	7.2	10.1	8.8	11.4	11.6
Housing Starts (thousands)											
2010	**191**	26.7	26.9	6.0	6.1	60.7	50.9	4.5	4.4	0.8	4.1
2011	**193**	26.3	25.5	7.1	5.9	67.7	48.2	3.2	4.7	1.0	3.6
2012	**215**	27.5	33.3	10.0	7.4	77.0	47.1	3.3	4.5	0.9	4.0
2013 f	**174**	21.2	32.0	8.0	6.6	55.0	40.0	2.7	4.8	0.8	3.4
2014 f	**170**	20.5	31.4	7.5	6.0	53.5	40.0	2.7	4.8	0.8	3.3
Consumer Price Index (% change)											
2010	**1.8**	1.4	1.0	1.3	0.8	2.4	1.3	2.1	2.2	1.8	2.4
2011	**2.9**	2.4	2.4	2.8	3.0	3.1	3.0	3.5	3.8	2.9	3.4
2012	**1.5**	1.1	1.1	1.6	1.6	1.4	2.1	1.7	1.9	2.0	2.1
2013 f	**1.0**	0.3	1.4	1.4	1.3	1.1	1.0	0.9	1.3	1.3	1.5
2014 f	**1.7**	1.7	2.1	2.2	1.8	1.7	1.6	1.4	1.6	1.4	1.9

Quarterly Forecasts	12Q4	13Q1f	13Q2f	13Q3f	13Q4f	14Q1f	14Q2f	14Q3f	14Q4f
Canada									
Real GDP (q/q, ann. % change)	0.6	1.8	1.9	2.2	2.3	2.4	2.4	2.5	2.6
Real GDP (y/y, % change)	1.1	1.3	1.3	1.6	2.0	2.2	2.3	2.4	2.5
Consumer Prices (y/y, % change)	0.9	0.7	0.8	1.3	1.7	1.9	1.9	2.0	2.0
Core CPI (y/y % change)	1.2	1.1	1.1	1.4	1.5	1.7	1.7	1.9	1.9
United States									
Real GDP (q/q, ann. % change)	0.1	2.4	2.4	2.6	2.6	2.8	2.8	3.0	3.0
Real GDP (y/y, % change)	1.6	1.7	2.0	1.9	2.5	2.6	2.7	2.8	2.9
Consumer Prices (y/y, % change)	1.9	1.8	2.0	2.0	2.0	2.0	2.2	2.2	2.2
Core CPI (y/y % change)	1.9	1.9	1.8	1.9	1.9	1.9	2.0	2.0	2.0
Financial Markets									
Central Bank Rates				(%, end of period)					
Americas									
Bank of Canada	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
U.S. Federal Reserve	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Bank of Mexico	4.50	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Central Bank of Brazil	7.25	7.25	7.25	7.25	8.25	8.75	9.00	9.00	9.00
Bank of the Republic of Colombia	4.25	3.25	3.25	3.25	3.25	4.00	4.00	4.50	4.50
Central Reserve Bank of Peru	4.25	4.25	4.25	4.25	4.25	4.25	4.50	5.00	5.00
Central Bank of Chile	5.00	5.00	5.00	5.00	5.50	5.75	5.75	5.75	5.75
Europe									
European Central Bank	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Bank of England	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Swiss National Bank	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Asia/Oceania									
Bank of Japan	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Reserve Bank of Australia	3.00	3.00	3.00	3.00	3.25	3.25	3.50	3.50	3.75
People's Bank of China	6.00	6.00	6.00	6.00	6.30	6.30	6.60	6.60	6.60
Reserve Bank of India	8.00	7.50	7.00	6.75	6.75	6.75	6.75	7.00	7.25
Bank of Korea	2.75	2.75	2.75	3.00	3.00	3.25	3.25	3.50	3.50
Bank Indonesia	5.75	5.75	5.75	6.00	6.00	6.25	6.50	6.75	7.00
Bank of Thailand	2.75	2.75	2.75	3.00	3.00	3.25	3.25	3.50	3.50
Canada									
3-month T-bill	0.93	0.97	1.00	1.00	1.00	1.00	1.00	1.00	1.10
2-year Canada	1.14	1.00	1.10	1.20	1.40	1.65	1.85	2.05	2.25
5-year Canada	1.38	1.30	1.35	1.60	1.75	2.05	2.25	2.45	2.70
10-year Canada	1.80	1.75	1.65	1.95	2.10	2.45	2.75	3.10	3.35
30-year Canada	2.37	2.50	2.45	2.75	2.95	3.30	3.45	3.60	3.65
United States									
3-month T-bill	0.04	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10
2-year Treasury	0.25	0.25	0.25	0.35	0.40	0.50	0.75	1.00	1.30
5-year Treasury	0.72	0.75	0.80	1.10	1.30	1.60	1.80	2.00	2.20
10-year Treasury	1.76	1.85	1.75	2.05	2.25	2.60	2.90	3.25	3.50
30-year Treasury	2.95	3.10	3.00	3.20	3.40	3.75	4.00	4.15	4.20
Canada-U.S. Spreads									
3-month T-bill	0.89	0.89	0.90	0.90	0.90	0.90	0.90	0.90	1.00
2-year	0.89	0.75	0.85	0.85	1.00	1.15	1.10	1.05	0.95
5-year	0.66	0.55	0.55	0.50	0.45	0.45	0.45	0.45	0.50
10-year	0.04	-0.10	-0.10	-0.10	-0.15	-0.15	-0.15	-0.15	-0.15
30-year	-0.58	-0.60	-0.55	-0.45	-0.45	-0.45	-0.55	-0.55	-0.55

INTEREST RATE OUTLOOK												
	Annual Average						End of Period					
	12	13F	14F	15F	16F	17F	12	13F	14F	15F	16F	17F
U.S. FIXED INCOME												
Fed Funds Target Rate (%)	0.25	0.25	0.25	0.45	1.90	3.25	0.25	0.25	0.25	0.75	2.50	3.50
3-mth T-Bill Rate (%)	0.10	0.15	0.35	0.80	2.20	3.70	0.05	0.20	0.40	1.05	2.80	4.00
2-yr Govt. Bond Yield (%)	0.30	0.30	0.60	1.35	2.40	3.90	0.25	0.35	0.80	1.90	2.95	4.25
5-yr Govt. Bond Yield (%)	0.80	0.95	1.50	2.45	3.45	4.30	0.72	1.10	1.75	2.90	3.95	4.50
10-yr Govt. Bond Yield (%)	1.85	2.10	2.75	3.75	4.60	4.85	1.78	2.30	3.00	4.00	5.00	4.75
10-yr-2-yr Govt. Spread (%)	1.55	1.80	2.15	2.40	2.20	0.95	1.53	1.95	2.20	2.10	2.05	1.45
CANADIAN FIXED INCOME												
Overnight Target Rate (%)	1.00	1.00	1.15	1.70	2.45	3.20	1.00	1.00	1.50	2.00	2.75	3.50
3-mth T-Bill Rate (%)	0.90	0.95	1.10	1.70	2.60	3.20	0.92	0.95	1.40	1.95	2.95	3.45
2-yr Govt. Bond Yield (%)	1.10	1.10	1.45	2.20	2.90	3.55	1.14	1.20	1.70	2.45	3.15	3.75
5-yr Govt. Bond Yield (%)	1.40	1.50	1.90	2.60	3.40	4.05	1.38	1.60	2.05	2.90	3.80	4.15
10-yr Govt. Bond Yield (%)	1.85	2.05	2.55	3.35	4.15	4.60	1.80	2.20	2.70	3.60	4.50	4.60
10-yr-2-yr Govt. Spread (%)	0.75	0.95	1.10	1.15	1.25	1.05	0.66	1.00	1.00	1.15	1.35	0.85

F: Forecast by TD Bank Group as at March 2013

Source: Statistics Canada, Bank of Canada, Bloomberg

MARKET CALL

- There's no reason to change our call that the Fed is on hold through mid-2015, but that call rests on a view that the end of QE will bring less stimulative rates at the long end (see pages 3-5). Frankly, we're surprised at how well long rates held in (for both the US, and by extension, Canada) given that our once top-of-consensus forecast for US Q1 growth is now a much more widely held view. European news is part of that story, and since we see a lingering impact from those risks, and US growth will slow towards mid-year, we've pushed off most of our projected bond market sell off until late this year.

- The changing of the guard at the Bank of Canada isn't likely to alter its stand-pat stance, particularly with household credit growth in check. We've slowed the path ahead for 2-year rates as we've chipped our forecast for growth slightly downward, but are in agreement with the Bank that its next move, well off in H2 2014 or even early 2015, will be a hike not a cut.

- Having moved more than half way there, dollar-Canada pulled back from our June 1.05 target. But we're sticking to our guns on that call, expecting softness in global growth to take some of the shine off our commodities-linked currency. We remain bulls on the US dollar overall, see the euro vulnerable to political and banking developments, and the Aussie dollar to lower rates and resource price softness.

INTEREST & FOREIGN EXCHANGE RATES

		2013	2013			2014			
END OF PERIOD:		**2-Apr**	**Jun**	**Sep**	**Dec**	**Mar**	**Jun**	**Sep**	**Dec**
CDA	Overnight target rate	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50
	98-Day Treasury Bills	0.96	0.95	0.95	0.95	0.95	1.10	1.30	1.60
	2-Year Gov't Bond	1.00	1.10	1.20	1.45	1.55	1.70	2.00	2.20
	10-Year Gov't Bond	1.87	2.00	2.10	2.40	2.55	2.70	2.80	2.85
	30-Year Gov't Bond	2.51	2.60	2.70	2.90	3.00	3.05	3.10	3.15
U.S.	Federal Funds Rate	0.16	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	91-Day Treasury Bills	0.07	0.10	0.15	0.15	0.15	0.15	0.15	0.15
	2-Year Gov't Note	0.24	0.30	0.35	0.45	0.45	0.60	0.80	1.10
	10-Year Gov't Note	1.86	2.00	2.15	2.45	2.60	2.70	2.75	2.80
	30-Year Gov't Bond	3.10	3.20	3.35	3.60	3.70	3.75	3.80	3.90
Canada - US T-Bill Spread		0.90	0.85	0.80	0.80	0.80	0.95	1.15	1.45
Canada - US 10-Year Bond Spread		0.01	0.00	-0.05	-0.05	-0.05	0.00	0.05	0.05
Canada Yield Curve (30-Year — 2-Year)		1.51	1.50	1.50	1.45	1.45	1.35	1.10	0.95
US Yield Curve (30-Year — 2-Year)		2.86	2.90	3.00	3.15	3.25	3.15	3.00	2.80
EXCHANGE RATES	CADUSD	0.99	0.95	0.96	0.97	0.99	1.02	1.04	1.02
	USDCAD	1.01	1.05	1.04	1.03	1.01	0.98	0.96	0.98
	USDJPY	93	96	95	94	93	92	91	90
	EURUSD	1.28	1.27	1.25	1.28	1.28	1.30	1.31	1.32
	GBPUSD	1.51	1.47	1.45	1.49	1.50	1.53	1.55	1.57
	AUDUSD	1.05	0.99	0.96	0.99	1.01	1.03	1.04	1.06
	USDCHF	0.95	0.96	0.98	0.96	0.97	0.96	0.95	0.97
	USDBRL	2.02	1.92	1.93	1.95	1.94	1.97	2.01	2.05
	USDMXN	12.28	12.64	12.66	12.75	12.82	12.88	12.95	12.95

Financial market forecast detail

Interest rates—North America

%, end of period

	Actual				Forecast								Actual		Forecast	
	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	2011	2012	2013	2014
Canada																
Overnight	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50	1.00	1.00	1.00	1.50
Three-month	0.92	0.88	0.90	1.05	0.95	1.00	1.00	1.00	1.05	1.10	1.25	1.55	1.10	1.05	1.00	1.55
Two-year	1.20	1.03	1.15	1.05	1.00	0.90	1.05	1.10	1.15	1.25	1.45	1.70	1.00	1.05	1.10	1.70
Five-year	1.56	1.25	1.35	1.30	1.30	1.20	1.40	1.50	1.55	1.70	1.90	2.15	1.50	1.30	1.50	2.15
10-year	2.11	1.74	1.75	1.75	1.80	1.85	1.95	2.10	2.15	2.30	2.50	2.80	2.30	1.75	2.10	2.80
30-year	2.64	2.33	2.40	2.40	2.50	2.55	2.65	2.70	2.70	2.75	2.90	3.15	3.10	2.40	2.70	3.15
Yield curve (10s-2s)	91	71	60	70	80	95	90	100	100	105	105	110	130	70	100	110
United States																
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Three-month	0.07	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Two-year	0.34	0.25	0.25	0.25	0.25	0.25	0.35	0.45	0.65	0.85	1.00	1.25	0.30	0.25	0.45	1.25
Five-year	1.04	0.70	0.72	0.70	0.85	0.90	1.05	1.20	1.40	1.50	1.75	2.00	1.10	0.70	1.20	2.00
10-year	2.20	1.60	1.65	1.70	1.95	2.10	2.25	2.40	2.55	2.65	2.95	3.25	2.15	1.70	2.40	3.25
30-year	3.32	2.70	2.80	2.90	3.25	3.45	3.60	3.85	3.95	4.00	4.20	4.50	3.20	2.90	3.85	4.50
Yield curve (10s-2s)	186	135	140	145	170	185	190	195	190	180	195	200	185	145	195	200
Yield spreads																
Three-month T-bills	0.85	0.83	0.85	1.00	0.90	0.95	0.95	0.95	1.00	1.05	1.20	1.50	1.05	1.00	0.95	1.50
Two-year	0.86	0.78	0.90	0.80	0.75	0.65	0.70	0.65	0.50	0.40	0.45	0.45	0.70	0.80	0.65	0.45
Five-year	0.52	0.55	0.63	0.60	0.45	0.30	0.35	0.30	0.15	0.20	0.15	0.15	0.40	0.60	0.30	0.15
10-year	-0.09	0.14	0.10	0.05	-0.15	-0.25	-0.30	-0.30	-0.40	-0.35	-0.45	-0.45	0.15	0.05	-0.30	-0.45
30-year	-0.68	-0.37	-0.40	-0.50	-0.75	-0.90	-0.95	-1.15	-1.25	-1.25	-1.30	-1.35	-0.10	-0.50	-1.15	-1.35

Interest rates—International

%, end of period

	Actual				Forecast								Actual		Forecast	
	12Q1	12Q2	12Q3	12Q4	13Q1	13Q2	13Q3	13Q4	14Q1	14Q2	14Q3	14Q4	2011	2012	2013	2014
United Kingdom																
Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Two-year	0.43	0.40	0.20	0.20	0.20	0.20	0.30	0.30	0.30	0.30	0.40	0.40	0.70	0.20	0.30	0.40
10-year	2.00	1.80	1.70	1.70	1.75	1.80	2.00	2.00	2.00	2.25	2.35	2.50	2.45	1.70	2.00	2.50
Euro Area																
Refinancing rate	1.00	1.00	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	1.00	0.75	0.75	0.75
Two-year	0.09	0.10	0.00	0.00	0.10	0.15	0.20	0.25	0.30	0.30	0.40	0.40	0.65	0.00	0.25	0.40
10-year	1.61	1.50	1.50	1.50	1.60	1.70	1.85	2.00	2.00	2.10	2.20	2.25	2.20	1.50	2.00	2.25
Australia																
Cash target rate	4.25	3.50	3.50	3.00	3.00	2.75	2.75	2.75	2.75	2.75	2.75	3.00	4.25	3.00	2.75	3.00
Two-year	3.49	2.46	2.49	2.75	2.70	2.80	2.90	3.10	3.25	3.30	3.40	3.50	3.15	2.75	3.10	3.50
10-year	4.10	3.04	2.94	3.00	3.45	3.60	3.65	3.70	3.85	3.95	4.35	4.75	4.05	3.00	3.70	4.75
New Zealand																
Cash target rate	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.75	3.00	3.00	3.25	2.50	2.50	2.50	3.25
Two-year	3.11	2.37	2.55	2.60	2.70	2.70	2.80	2.90	3.00	3.20	3.40	3.50	2.85	2.60	2.90	3.50
10-year	4.17	3.40	3.57	3.80	4.00	4.10	4.25	4.50	4.70	4.80	5.10	5.50	4.25	3.80	4.50	5.50

Canadian Economic Outlook

BMO Capital Markets Economics

May 24, 2013

	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2	2013 Q3	2013 Q4	2014 Q1	2014 Q2	2014 Q3	2014 Q4	2011	2012	2013	2014
PRODUCTION	**(quarter/quarter % change : a.r.)**															
Real GDP (chain-weighted)	1.2	1.9	0.7	0.6	2.3	1.8	2.1	2.4	2.5	2.5	2.2	2.0	2.6	1.8	1.6	2.3
Final Sales	-0.2	1.5	-1.9	3.2	2.0	1.4	2.1	2.4	2.5	2.5	2.2	2.0	2.3	1.6	1.6	2.3
Final Domestic Demand	2.3	1.8	0.9	2.6	0.6	1.3	1.8	2.1	2.3	2.3	2.1	1.9	2.7	1.9	1.5	2.1
Consumer Spending	2.2	0.5	2.8	2.7	1.6	2.0	2.2	2.3	2.3	2.2	2.1	1.9	2.4	1.9	2.1	2.2
Durables	5.3	-3.8	3.1	3.8	2.5	1.7	1.8	2.0	2.2	2.0	1.8	1.5	1.8	2.8	2.1	2.0
Non-Durables	-1.8	2.1	3.8	2.6	1.0	2.0	2.2	2.2	2.0	2.0	1.9	1.7	1.4	0.9	2.1	2.0
Services	3.3	1.3	2.2	2.8	1.8	2.1	2.3	2.3	2.4	2.3	2.2	2.1	2.9	2.2	2.1	2.3
Government Spending	-1.1	2.2	-1.6	2.4	-1.1	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	-0.6	0.1	0.3
Business Investment	8.1	8.3	-0.4	4.4	3.4	3.8	6.0	8.0	8.5	9.0	7.2	6.2	10.4	6.2	4.1	7.6
Non-Residential Construction	9.2	14.5	-2.1	6.5	4.0	4.3	6.6	8.0	8.5	9.0	8.0	7.0	10.2	8.0	4.9	7.8
Machinery and Equipment	6.5	0.1	2.1	1.2	2.5	3.0	5.0	8.0	8.5	9.0	6.0	5.0	10.7	3.7	2.8	7.2
Residential Construction	14.4	0.6	-2.4	0.8	-6.0	-4.5	-2.0	-2.0	-2.0	-1.5	-1.0	0.0	1.9	5.8	-2.9	-1.8
Exports	-3.3	1.1	-7.3	1.2	6.8	3.7	4.6	4.9	5.0	5.1	4.7	4.3	4.6	1.6	2.6	4.8
Imports	5.1	2.3	2.1	-1.0	1.8	3.0	3.8	4.0	4.2	4.3	4.1	3.8	5.8	2.9	1.9	4.0
	(billions of chained 2007 dollars : a.r.)															
Inventory Change	3.3	3.2	13.0	2.7	3.8	5.1	5.1	5.4	5.4	5.4	5.5	5.5	1.6	5.5	4.8	5.4
Contribution to GDP Growth	2.1	0.1	2.5	-2.6	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	-0.0	0.0
Net Exports	-37.5	-39.3	-51.8	-48.9	-43.0	-42.4	-41.8	-41.1	-40.5	-39.8	-39.3	-39.1	-36.9	-44.4	-42.1	-39.7
Contribution to GDP Growth	-2.7	-0.4	-2.9	0.7	1.4	0.2	0.2	0.2	0.2	0.2	0.1	0.1	-0.5	-0.4	0.2	0.2
	(billions of dollars : a.r.)															
Nominal GDP	1,804	1,808	1,825	1,833	1,851	1,867	1,884	1,905	1,927	1,949	1,969	1,988	1,762	1,818	1,877	1,958
(% chng : a.r.)	1.1	0.9	3.6	1.9	3.9	3.6	3.8	4.3	4.7	4.7	4.2	4.0	5.9	3.1	3.3	4.3
INFLATION	**(quarter/quarter % change : a.r.)**															
GDP Price Index	0.0	-0.7	2.6	1.5	1.6	1.8	1.7	1.9	2.2	2.1	1.9	1.9	3.2	1.3	1.6	2.0
CPI All Items	2.0	0.2	0.1	1.4	1.6	-0.1	1.7	1.8	1.9	1.9	1.9	2.2	2.9	1.5	1.0	1.7
Excl. Food & Energy	1.9	1.6	-0.7	0.7	1.6	1.2	1.6	1.8	1.8	1.9	1.8	2.2	1.6	1.3	1.1	1.8
Food Prices	2.1	0.6	2.6	1.4	1.8	-0.3	1.7	1.9	2.1	2.2	2.0	1.9	3.8	2.4	1.4	1.9
Energy Prices	4.3	-8.3	3.5	1.7	3.6	-7.4	3.0	1.9	2.2	2.1	2.0	2.3	12.3	1.7	0.2	1.6
Services	1.5	3.8	0.9	0.3	0.6	1.4	1.6	1.9	2.2	2.3	2.0	2.0	2.5	2.0	1.2	2.0
	(year/year % change)															
CPI All Items	2.3	1.6	1.2	0.9	0.9	0.8	1.2	1.3	1.3	1.8	1.9	2.0				
BoC Core	2.1	2.0	1.5	1.2	1.3	1.2	1.4	1.5	1.6	1.7	1.8	1.9	1.7	1.7	1.4	1.8
FINANCIAL	**(average for the quarter : %)**															
Overnight Rate	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.25	1.50	1.00	1.00	1.00	1.19
3-Month T-Bill	0.88	0.95	0.97	0.96	0.95	0.99	1.00	1.00	1.00	1.00	1.25	1.50	0.91	0.94	0.98	1.19
90-Day BAs	1.20	1.24	1.21	1.19	1.20	1.18	1.18	1.18	1.18	1.18	1.42	1.66	1.23	1.21	1.18	1.36
10 Year Bond Yield	2.04	1.91	1.78	1.77	1.92	1.86	2.09	2.29	2.51	2.74	2.98	3.24	2.78	1.87	2.04	2.87
Canada/US spread: (bps)																
90 day	81	86	86	87	86	94	95	95	95	95	120	145	86	85	93	114
10 year	0	9	13	7	-3	-3	-6	-5	-4	-1	2	6	0	7	-4	1
FOREIGN TRADE	**(billions of dollars : a.r.)**															
Current Account Balance	-54.9	-71.7	-72.2	-69.0	-65.5	-64.7	-63.6	-62.4	-61.4	-60.4	-59.5	-58.8	-52.3	-66.9	-64.0	-60.0
(% of GDP)	-3.0	-4.0	-4.0	-3.8	-3.5	-3.5	-3.4	-3.3	-3.2	-3.1	-3.0	-3.0	-3.0	-3.7	-3.4	-3.1
Merchandise Balance	-1.0	-15.0	-20.4	-11.1	-6.7	-5.7	-4.5	-3.3	-1.9	-0.5	0.6	1.5	0.9	-11.9	-5.1	-0.1
Non-Merchandise Balance	-53.9	-56.6	-51.8	-57.9	-58.9	-59.0	-59.0	-59.1	-59.4	-59.9	-60.1	-60.4	-53.2	-55.1	-59.0	-59.9
	(average for the quarter)															
Exchange Rate (US¢/C$)	99.9	99.0	100.5	100.9	99.1	98.1	96.0	96.8	98.0	98.6	99.2	99.8	101.2	100.1	97.5	98.9
Exchange Rate (C$/US$)	1.001	1.010	0.995	0.991	1.009	1.019	1.041	1.033	1.021	1.015	1.008	1.002	0.989	0.999	1.026	1.011
Exchange Rate (¥/C$)	79.2	79.3	79.0	82.0	91.5	98.2	98.6	101.1	103.7	105.5	107.4	109.4	80.7	79.9	97.4	106.5
Exchange Rate (C$/Euro)	1.31	1.30	1.25	1.29	1.33	1.32	1.34	1.30	1.28	1.29	1.29	1.30	1.38	1.29	1.32	1.29
INCOMES	**(year/year % change)**															
Corporate Profits Before Tax	0.6	-0.1	-4.9	-7.5	-0.9	5.4	5.9	2.5	3.6	4.0	4.2	4.3	22.8	-3.1	3.2	4.0
Corporate Profits After Tax	5.1	10.6	7.5	0.1	5.5	4.5	6.2	0.6	4.2	4.6	4.8	4.8	18.3	5.6	4.2	4.6
Personal Income	3.9	4.1	4.0	3.7	3.7	3.4	3.6	4.2	4.2	4.3	4.3	4.2	4.3	3.9	3.7	4.2
Real Disposable Income	1.7	2.5	2.2	2.1	1.9	1.3	1.7	2.2	2.2	2.3	2.3	2.2	1.6	2.1	1.8	2.2
	(average for the quarter : %)															
Savings Rate	3.7	4.5	4.2	3.8	3.7	3.6	3.7	3.9	3.7	3.7	3.8	4.0	3.8	4.0	3.7	3.8
OTHER INDICATORS	**(quarter average)**															
Unemployment Rate (%)	7.4	7.3	7.3	7.2	7.1	7.1	7.0	6.9	6.8	6.7	6.6	6.6	7.5	7.3	7.0	6.7
Housing Starts (000s, a.r.)	205	231	222	202	174	175	174	174	172	167	170	173	193	215	175	170
Existing Home Sales (y/y % ch)	3.9	6.7	-4.1	-10.4	-10.3	-8.3	-3.2	0.5	1.8	2.0	3.2	3.1	2.7	-1.1	-5.5	2.5
Home Prices (y/y % ch, CREA)	1.6	-0.6	-0.1	0.1	0.6	1.4	0.5	-0.7	-1.6	-1.0	1.6	2.8	7.0	0.2	0.5	0.5
Motor Vehicle Sales (mlns, a.r.)	1.76	1.71	1.71	1.70	1.71	1.69	1.69	1.70	1.70	1.69	1.69	1.69	1.62	1.72	1.70	1.69
	(quarter/quarter % change : a.r.)															
Employment Growth	0.8	2.6	0.6	2.4	0.8	0.3	1.1	1.5	1.4	1.5	1.4	1.2	1.5	1.2	1.2	1.3
Industrial Production	-0.9	1.3	-2.3	0.5	5.0	2.5	2.7	2.5	2.4	2.5	2.4	2.3	3.8	1.1	2.1	2.5
Federal Budget Balance (% of FY GDP)													-1.5	-1.4	-1.0	-0.3

Note: Outlined areas represent forecast periods

NATIONAL BANK
FINANCIAL MARKETS
A division of National Bank of Canada

Monthly ECONOMIC MONITOR

June 2013

Highlights

- *Global economic growth continues to be soft with little prospect for an acceleration over the near term. The U.S. is in sequestration mode, Europe remains anchored in recession, while emerging Asia is now saddled with a relative loss of competitiveness thanks to the yen's slump. All told, things are evolving much in line with our view that global GDP growth will be a tepid 3.1% this year.*

- *As we had expected, the US economy is decelerating in the current quarter. Employment creation and output growth are well off the pace of early 2013, likely impacted by sequester-related uncertainties that may have disrupted business plans. The ramp down in factory activity in early Q2 is, however, being offset by resilient consumers whose confidence is being buoyed by short term developments, namely cheaper gasoline and a stock market rally, as well as more structural long-term factors such as better credit and rising home prices. Those suggest the US economy is in a position to bounce back in the second half of the year after the Q2 slowdown.*

- *First quarter economic growth in Canada was likely much better than what the Bank of Canada had anticipated. But that's not to say that our central bank is about to turn hawkish. The current quarter isn't looking promising given the deceleration in the US which suggests a likely moderation in trade after a strong Q1. Domestic demand is also looking soft, not just due to the weakening housing market or the fiscal drag from government, but also because debt-laden consumers are unlikely to maintain the splurge of recent quarters. With that backdrop, inflation is set to remain very mild, which argues for the removal of the BoC's tightening bias.*

				Change from Previous Forecast	
	2012	**2013**	**2014**	**2013**	**2014**
United States					
GDP	2.2%	1.8%	2.7%	unch	unch
CPI inflation	2.1%	1.3%	1.7%	-0.5 pp	-0.5 pp
Fed Fund Target Rate*	0.25%	0.25%	0.25%	unch	unch
Ten-year bond yield*	1.76%	2.35%	3.02%	+29 bp	+27 bp
Canada					
GDP	1.8%	1.5%	2.2%	unch	unch
CPI inflation	1.5%	1.0%	1.6%	-0.1 pp	-0.3 pp
Overnight rate*	1.00%	1.00%	1.00%	unch	unch
Ten-year bond yield*	1.80%	2.27%	3.11%	+14 bp	+39 bp

* end of period

ECONOMIC AND STRATEGY GROUP – 514.879.2529
Stéfane Marion, Chief Economist and Strategist

Appendix E2

FORECASTING TABLES

WEATHER DATA 2004 - 2012

Annual Heating Degree Days, by Region

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Lower Mainland	2,525	2,664	2,714	2,889	3,043	2,921	2,621	2968	2851
Inland	3,631	3,702	3,637	3,778	4,093	4,077	3,646	3,978	3784
Columbia	4,273	4,483	4,217	4,406	4,654	4,650	4,382	4,574	4321
Revelstoke	4,004	3,987	3,833	4,124	4,226	4,098	3,729	4,089	3924
Fort Nelson	6,805	6,211	6,607	6,796	6,887	7,132	6,444	6,612	6842
Vancouver Island	2,663	2,769	2,793	2,952	3,163	3,048	2,854	3,160	3157
Whistler	3,832	3,935	3,906	4,099	4,272	4,178	4,095	4,189	4536

Notes:

1. Vancouver airport weather station

2 Simple average of the Castlegar, Kelowna, Penticton and Prince George airport weather stations

3. Cranbrook airport weather station

4. Revelstoke airport weather station

5. Heating degree days are ba HDD18 = Maximum(0, 18 - Temperature)

6. Vancouver Island data from Finance

BC Housing Starts Forecast

	2010	2011	2012	2013
Single-Detached Housing Starts (Units)	11,462	11,300	11,900	12,368
Percent Change	45.2%	-1.4%	5.3%	3.9%
Multiple Housing Starts (Units)	15,017	15,600	17,100	18,123
Percent Change	83.5%	3.9%	9.6%	6.0%
Housing Starts Total	**26,479**	**26,900**	**29,000**	**30,490**

Sources: CMHC, The Conference Board of Canada

As of November 16th, 2012

BC Housing Starts Forecast

	2010	2011	2012F	2013F	2014F	2015F	2016F	2017F	2018F
Single-Detached Housing Starts (Units)	11,462	8,867	8,142	7,854	8415	9027	9213	8974	8663
Percent Change	45.2%	-22.6%	-8.2%	-3.5%	7.1%	7.3%	2.1%	-2.6%	-3.5%
Multiple Housing Starts (Units)	15,017	17,533	20,213	19,186	19,586	21,915	23,260	23,291	22,649
Percent Change	83.5%	16.8%	15.3%	-5.1%	2.1%	11.9%	6.1%	0.1%	-2.8%
Housing Starts Total	**26,479**	**26,400**	**28,355**	**27,040**	**28,001**	**30,942**	**32,473**	**32,265**	**31,312**

Sources: CMHC, The Conference Board of Canada

CUSTOMER ADDITIONS 2004 - 2018

Lower Mainland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential[1]	7,802	7,833	6,159	8,053	4,636	3,183	4,574	3,356	2,413	2,323	2,471	2,667	2,738	2,678	2,589
Commercial[2]	375	647	358	890	895	226	35	187	108	138	182	178	166	175	173
Industrial & Transportation[3]	38	-68	34	-102	-47	-17	-88	-50	-9	0	0	0	0	0	0
Total Net Additions	**8,215**	**8,412**	**6,551**	**8,841**	**5,484**	**3,392**	**4,521**	**3,493**	**2,512**	**2,461**	**2,653**	**2,845**	**2,904**	**2,853**	**2,762**
Year-End Customers	551,241	559,653	566,204	575,045	580,529	583,921	588,442	591,934	583,979	586,424	589,076	591,921	594,825	597,678	600,440

Inland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential[1]	2,759	3,385	3,243	3,583	3,040	1,479	2,028	1,545	1,959	1,886	2,008	2,165	2,221	2,171	2,098
Commercial[2]	349	299	286	186	342	87	110	209	144	162	184	173	173	176	174
Industrial & Transportation[3]	14	-22	5	-20	-8	-12	-6	-17	6	0	0	0	0	0	0
Total Net Additions	**3,122**	**3,662**	**3,534**	**3,749**	**3,374**	**1,554**	**2,132**	**1,737**	**2,109**	**2,048**	**2,192**	**2,338**	**2,394**	**2,347**	**2,272**
Year-End Customers	213,151	216,813	220,347	224,096	227,470	229,024	231,156	232,893	231,020	233,064	235,256	237,594	239,988	242,335	244,607

Columbia Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential[1]	111	194	181	338	267	160	222	100	111	107	115	123	126	123	119
Commercial[2]	22	21	11	14	46	-15	-2	23	17	14	20	18	17	18	17
Industrial & Transportation[3]	-4	-1	-1	-4	1	-2	-2	0	-1	0	0	0	0	0	0
Total Net Additions	**129**	**214**	**191**	**348**	**314**	**143**	**218**	**123**	**127**	**121**	**135**	**141**	**143**	**141**	**136**
Year-End Customers	21,248	21,462	21,653	22,001	22,315	22,458	22,676	22,799	22,538	22,659	22,794	22,935	23,078	23,219	23,355

Revelstoke Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential[1]	44	15	12	29	16	0	0	-7	-8	0	0	0	0	0	0
Commercial[2]	10	1	3	2	11	1	-2	-2	3	1	2	4	2	3	3
Total Net Additions	**54**	**16**	**15**	**31**	**27**	**1**	**-2**	**-9**	**-5**	**1**	**2**	**4**	**2**	**3**	**3**
Year-End Customers	1,483	1,499	1,514	1,545	1,572	1,573	1,571	1,562	1,503	1,504	1,506	1,510	1,512	1,515	1,518

Mainland (Sum of Lower Mainland, Inland, Columbia and Revelstoke) :

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017	2018F
Residential[1]	10,716	11,427	9,595	12,003	7,959	4,822	6,824	4,994	4,475	4,316	4,594	4,955	5,085	4,972	4,806
Commercial[2]	756	968	658	1,092	1,294	299	141	417	272	315	388	373	358	372	367
Industrial & Transportation[3]	48	-91	38	-126	-54	-31	-96	-67	-4	0	0	0	0	0	0
Total Net Additions	**11,520**	**12,304**	**10,291**	**12,969**	**9,199**	**5,090**	**6,869**	**5,344**	**4,743**	**4,631**	**4,982**	**5,328**	**5,443**	**5,344**	**5,173**
Year-End Customers	787,123	799,427	809,718	822,687	831,886	836,976	843,845	849,188	839,040	843,651	848,632	853,960	859,403	864,747	869,920

Notes:

1. Rate 1
2. Rates 2, 3, and 23
3. Rates 4, 5, 6, 7, 22, 25, and 27 (exclude Rate 16)
9. Rates 2.1, 2.2
10. Rate 25

NORMALIZED ACTUAL USE PER CUSTOMER RATES 2004 - 2018 (GJ/yr)

Lower Mainland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Rate 1	109.8	103.6	103.2	102.6	99.5	100.2	99.8	97.1	98.6	97.8	97.0	96.2	95.5	94.7	93.9
Rate 2	322.9	314.2	324.8	327.4	326.4	335.6	324.7	329.3	355.8	350.5	351.6	352.8	354.0	355.3	356.3
Rate 3	3,485.3	3,364.7	3,266.9	3,404.6	3,406.3	3,352.9	3,338.3	3,484.6	3,522.0	3,685.8	3,715.0	3,744.6	3,774.4	3,804.2	3,834.4
Rate 23	5,016.9	4,699.5	4,605.6	4,684.1	4,641.9	4,798.1	4,769.0	5,014.7	5,109.7	5,232.4	5,357.9	5,486.6	5,618.3	5,753.0	5,891.2

Inland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Rate 1	85.7	81.9	81.6	80.3	76.0	76.9	75.7	74.7	77.0	76.6	76.2	75.7	75.3	74.9	74.5
Rate 2	286.4	280.7	285.6	286.0	272.8	281.5	275.8	273.1	293.9	291.6	291.9	292.1	292.3	292.4	292.6
Rate 3	3,524.3	3,451.3	3,536.2	3,500.4	3,426.0	3,423.7	3,494.9	3,441.0	3,774.2	4,061.6	4,067.8	4,074.3	4,080.7	4,087.0	4,093.4
Rate 23	5,712.5	4,791.9	5,139.6	5,273.1	4,997.9	5,350.3	5,254.5	5,749.7	5,948.5	6,213.6	6,490.4	6,779.6	7,081.4	7,397.1	7,726.7

Columbia Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Rate 1	90.5	89.2	86.8	86.8	83.0	83.5	81.9	80.1	83.0	82.0	81.1	80.1	79.2	78.3	77.4
Rate 2	340.2	330.2	327.9	340.0	336.2	321.3	316.6	318.3	324.6	315.1	309.2	303.7	298.3	293.1	287.8
Rate 3	3,565.6	3,681.2	3,409.2	3,618.8	3,898.2	3,691.7	3,571.6	3,601.6	3,553.7	3,622.7	3,529.6	3,438.9	3,350.5	3,264.5	3,180.5
Rate 23	3,852.1	4,324.3	4,498.3	4,636.6	4,515.7	4,469.1	4,875.3	5,304.0	4,615.1	4,887.6	5,176.6	5,482.2	5,806.0	6,149.0	6,512.2

Revelstoke Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Rate 1	70.6	63.6	68.9	57.9	49.2	55.9	51.6	54.2	54.0	56.0	58.0	60.2	62.4	64.6	67.0
Rate 2	369.8	353.5	312.9	296.8	300.7	309.8	309.0	308.4	306.8	309.6	312.1	314.8	317.3	320.2	323.0
Rate 3	8,049.0	5,914.3	4,954.3	4,580.5	4,210.5	4,267.6	4,892.9	5,023.6	6,795.9	7,288.7	7,817.4	8,384.4	8,992.5	9,644.7	10,344.2

Mainland Consolidated - All Regions:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Rate 1	102.6	97.2	96.8	96.0	92.5	93.3	92.6	90.4	92.2	91.4	90.7	90.0	89.4	88.7	88.0
Rate 2	313.8	305.8	314.3	316.5	312.2	320.6	311.3	313.7	337.6	333.0	333.6	334.3	334.9	335.6	336.2
Rate 3	3,501	3,388	3,314	3,426	3,420	3,372	3,370	3,484	3,566	3,746	3,770	3,795	3,821	3,847	3,873
Rate 23	5,113	4,714	4,686	4,778	4,698	4,886	4,850	5,138	5,238	5,392	5,546	5,707	5,873	6,044	6,222

ACTUAL USE PER CUSTOMER RATES 2004- 2018 (GJ/yr)

Lower Mainland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Rate 1	99.2	102.0	101.8	109.0	110.3	106.8	93.0	103.9	100.3
Rate 2	294.8	308.9	319.1	347.6	359.7	352.5	302.7	351.5	361.5
Rate 3	3,249.7	3,312.9	3,221.6	3,553.1	3,651.1	3,426.7	3,208.9	3658.1	3569.6
Rate 23	4,607.6	4,564.5	4,569.0	4,881.2	4,870.8	4,961.2	4,546.1	5311.4	5186.5

Inland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Rate 1	82.4	82.0	79.0	82.5	84.0	85.0	72.1	78.3	76.1
Rate 2	275.1	282.1	274.2	295.5	306.2	314.1	260.9	287.5	290.0
Rate 3	3,422.0	3,467.7	3,376.2	3,575.6	3,723.0	3,648.2	3,270.5	3590.0	3755.4
Rate 23	5,505.6	4,790.4	5,016.2	5,379.2	5,313.4	5,604.0	5,152.7	5981.7	5963.5

Columbia Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Rate 1	87.1	89.3	82.8	86.6	87.4	87.8	80.7	82.5	81.0
Rate 2	325.9	325.6	318.0	336.4	348.8	340.5	310.2	329.3	316.5
Rate 3	3,439.1	3,636.9	3,340.1	3,551.2	3,989.3	3,825.1	3,572.4	3695.2	3491.0
Rate 23	3,736.6	4,325.5	4,341.0	4,673.7	4,729.7	4,675.2	4,810.6	5428.5	4524.7

Revelstoke Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Rate 1	64.4	62.0	69.2	59.5	51.7	59.1	46.5	55.6	52.2
Rate 2	349.1	350.0	284.8	307.4	317.4	319.8	285.6	316.5	300.2
Rate 3	7,768.9	5,836.2	4,649.3	4,676.9	4,358.1	4,380.1	4,680.6	5142.3	6745.7

Mainland Consolidated - All Regions:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Rate 1	94.2	96.1	95.0	101.1	102.3	100.2	86.8	96.2	93.0
Rate 2	291.0	302.0	307.0	333.0	345.0	341.7	291.6	333.5	340.2
Rate 3	3,287.0	3,348.0	3,251.0	3,560.0	3,669.0	3,468.9	3,228.0	3653.0	3601.4
Rate 23	4,754.0	4,596.0	4,638.0	4,959.0	4,944.0	5,064.7	4,648.5	5422.0	5302.1

NORMALIZED ACTUAL ENERGY DEMAND 2004 - 2018 (PJs)

Lower Mainland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	53.9	51.6	52.1	52.7	51.6	52.4	52.6	51.5	51.9	51.8	51.6	51.4	51.3	51.1	51
Commercial	35.1	33.9	34.0	35.2	35.7	36.6	36.2	37.6	37.8	38.3	38.8	39.4	40.1	40.8	41.4
Industrial	31.2	32.5	31.4	30.4	29.7	27.8	27.4	28.1	30.0	30.0	30.0	30.1	30.0	29.9	29.9
Total	**120.2**	**118.0**	**117.5**	**118.3**	**117.0**	**116.8**	**116.2**	**117.2**	**119.7**	**120.1**	**120.4**	**120.9**	**121.4**	**121.8**	**122.3**

Inland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	16.4	15.9	16.1	16.1	15.5	15.9	15.8	15.7	16.1	16.1	16.2	16.3	16.3	16.4	16.5
Commercial	9.0	8.8	9.0	9.2	9.0	9.4	9.3	9.4	9.9	10.2	10.3	10.5	10.7	11	11.2
Industrial	28.7	27.3	23.8	26.4	22.2	17.6	19.8	22.7	23.5	21.7	21.4	21.5	21.5	21.5	21.5
Total	**54.0**	**52.0**	**48.9**	**51.7**	**46.7**	**42.8**	**44.9**	**47.8**	**49.4**	**48.0**	**47.8**	**48.2**	**48.5**	**48.9**	**49.2**

Columbia Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.6	1.7	1.7	1.7	1.7	1.6	1.6	1.6
Commercial	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1	1	1	1.1	1.1
Industrial	3.7	3.5	3.1	3.2	3.5	3.0	4.3	6.9	6.4	6.5	6.5	6.5	6.5	6.5	6.5
Total	**6.4**	**6.1**	**5.7**	**6.0**	**6.2**	**5.8**	**7.0**	**9.5**	**9.1**	**9.2**	**9.2**	**9.2**	**9.1**	**9.2**	**9.2**

Revelstoke Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Total	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**	**0.3**

Mainland Consolidated - All Regions:

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013F	2014F	2015F	2016F	2017F	2018F
Residential	72.0	69.3	70.0	70.6	68.8	70.0	70.0	68.9	69.8	69.6	69.5	69.4	69.3	69.2	69.1
Commercial	45.2	43.9	44.1	45.5	45.9	47.2	46.6	48.1	48.9	49.6	50.2	51.1	52	52.9	53.9
Industrial	63.6	63.3	58.3	60.0	55.3	48.4	51.5	57.7	59.9	58.2	57.9	58.1	57.9	57.9	57.9
Total	**180.8**	**176.4**	**172.4**	**176.2**	**170.0**	**165.6**	**168.2**	**174.7**	**178.5**	**177.4**	**177.6**	**178.6**	**179.3**	**180.1**	**181.0**

ACTUAL ENERGY DEMAND 2004 - 2012 (PJs)

Lower Mainland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	48.4	51.1	51.3	56.2	58.8	53.2	48.7	50.5	52.5
Commercial[1]	32.2	33.4	33.8	37.3	38.6	38.3	35.0	39.8	38.4
Industrial	31.2	32.5	31.4	30.4	29.7	27.8	27.4	28.1	30.2
Total	**111.8**	**117.0**	**116.5**	**123.9**	**127.1**	**119.3**	**111.1**	**118.4**	**121.1**

Inland Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	15.8	16.0	15.4	16.7	17.6	16.8	14.8	15.4	16
Commercial[1]	8.7	8.9	8.6	9.5	10.1	10.1	8.9	9.8	9.8
Industrial	28.7	27.3	23.8	26.4	22.2	17.6	19.8	22.7	23.5
Total	**53.2**	**52.2**	**47.8**	**52.6**	**49.9**	**44.5**	**43.5**	**47.9**	**49.3**

Columbia Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	1.8	1.7	1.6	1.7	1.8	1.7	1.6	1.7	1.7
Commercial[1]	1.0	0.9	0.9	1.0	1.1	1.1	1.0	1.1	1.0
Industrial	3.7	3.5	3.1	3.2	3.5	3.0	4.3	6.9	6.4
Total	**6.5**	**6.1**	**5.6**	**5.9**	**6.4**	**5.8**	**6.9**	**9.7**	**9.1**

Revelstoke Region:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**	**0.2**

Mainland Consolidated - All Regions:

	2004	2005	2006	2007	2008	2009	2010	2011	2012
Residential	66.1	68.9	68.4	74.7	78.3	71.8	65.2	67.7	70.3
Commercial	42.1	43.3	43.4	47.9	49.9	49.6	45.0	50.9	49.3
Industrial	63.6	63.3	58.3	60.0	55.3	48.4	51.5	57.7	60.1
Total	**171.8**	**175.5**	**170.1**	**182.6**	**183.5**	**169.8**	**161.7**	**176.3**	**179.7**

Notes:

1. Rates 2, 3, and 23

Appendix E3

FORECASTING MODELS

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix E4

BCUC LETTER REGARDING CUSTOMER COUNT ADJUSTMENTS

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January 28, 2013

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Utilities (comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), FortisBC Energy (Whistler) Inc. ("FEW"), and FortisBC Energy (Vancouver Island) Inc.) ("FEVI"))

2012 Customer Count Adjustment

On June 2, 2009, the FortisBC Energy Utilities ("the FEU" or the "the Utilities")[1], applied to the British Columbia Utilities Commission (the "Commission") for a Certificate of Public Convenience and Necessity ("CPCN") for its Customer Care Enhancement Project (the "Project"). On February 26, 2010, a CPCN for the Project was granted under Order No. C-1-10.

This letter is to inform the Commision that the Project, which went live as of January 1, 2012, resulted in not only a new Customer Information System ("CIS"), but also a different definition of a customer and a one-time customer count adjustment. This customer count adjustment has no impact on historical results or on currently approved rates.

The following sections provide a summary of:

- The customer count adjustment;
- Why the Utilities' historical results and forecast rates are not affected; and
- How the customer count adjustment will be reflected in the Revenue Stabilization Adjustment Mechanism ("RSAM") account in 2012 and 2013, and in future filings with the Commission.

1. Customer Count Adjustment Summary

The FEI[2] General Terms and Conditions ("GT&Cs") define a Customer as follows:

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[1] Then Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc.
[2] The definition of a Customer for FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. are the same as that of FortisBC Energy Inc.

Means a Person who is being provided Service or who has filed an application for Service with FortisBC Energy that has been approved by FortisBC Energy.

This definition in the GT&Cs is for the purposes of determining who can be charged a rate by the utility. As such, this definition continues unchanged with the new CIS. The following discussion relates only to how the FEU calculates the number of customers, for purposes of reporting and for purposes of performance metrics.

In the previous CIS, the number of customers was determined at month-end using an algorithm that counted the number of services (meters) that were installed at a premise, where:

- The meter was not disconnected during the entire reporting period (month); or,
- The meter was disconnected during the reporting period, but a customer was attached to that premise for at least one day in that reporting period.

The above definition essentially means to be considered a customer, the service had to be active at some point during the month.

In the new SAP-based CIS, the algorithm for determining the number of customers is to count the number of valid contracts (for natural gas service) that are in effect on the reporting date (which can be any day of the month). For purposes of reporting monthly customer counts, the FEU use the mid-month report (based on the 15th of the reporting month).

These two definitions lead to different customer counts, and this is mainly due to what actually constitutes a customer in each system.

A customer in the new SAP-based CIS is defined as a valid contract to provide natural gas service. This definition results in a different customer count from that of the previous CIS in those situations where a premise becomes vacant or meters are disconnected during the reporting period. Under the new system these vacant premises or meter disconnects no longer have a valid contract as of the day the premise becomes vacant or the meter is disconnected. This is in contrast to the previous CIS where there was still an installed meter that received service during the reporting period. For example, if a customer was disconnected on January 10, under the previous CIS they would be reported as a customer for the month of January (as a meter would have been attached to that premise for at least one day during the month of January). Under the new CIS, however, they would be excluded.

Also contributing to the difference is the reporting period itself. The former CIS counted customers based on installed meters that were not disconnected over a particular reporting period (a particular calendar month). The new CIS, however, is more detailed and flexible, and enables the reporting of customer counts on a daily basis. This, in turn, provides a greater degree of precision when reporting the number of customers. Upon analyzing customer counts on various days of the month, the FEU have decided that mid-month (the 15th day of each month) is the appropriate reporting date for reporting customer counts. Using a mid-month date helps to smooth out differences seen in customer counts that are a result of customers moving, which typically occur around the end of the month and often include small timing differences between the date a customer calls for a move-in and the date a customer calls for a move-out.

The customer count adjustment is a one-time amendment effective January 1, 2012 and affects all of the FEU and most of the rate schedules, although the largest impact is to the FEI Rate Schedule 1 customer count, as described further below. The following Table 1 provides a summary of this one-time customer count adjustment.

Table 1: Customer Count Adjustment by Rate Schedule and Utility

Rate Schedule	FEI	FTFN	FEVI	FEW	TTL
Residential (FEI 1, FEVI RGS, FEW SGS RES)	10,316	16	2,332	76	12,740
Small Comm (FEI 2, FEVI AGS, SCS, LCS1, FEW SGS COM)	4,527	8	605	12	5,152
Large Comm (FEI 3, FEVI LCS2, LCS3)	44	-	92	-	136
Non Core	5				5
	14,892	24	3,029	88	18,033

The customer count adjustment of 18,033 as shown in Table 1 represents 1.9 percent of the FEU's customers. In comparison, when FEVI converted its CIS in 2006, it resulted in a similar adjustment of a 2 per cent reduction in the number of customers.

> *"The customer additions forecast prepared for the Settlement Update Filing is aligned with the results presented in the TGVI[3] 2006 Resource Plan with the exception of the total count of customers and the associated effect on use per customer rates. TGVI converted its customer database during the first half of 2006 to the system currently in use at TGI. In doing so, a number of accounts that were previously counted as customers did not meet the criteria for inclusion as active customers in the new system. To adjust for this, the total number of TGVI customers was retroactively decreased by 1,736 customers as of December 31, 2005."[4]*

The FEU understand, from speaking with one of its CIS consultants, Five Point Partners, LLC, that these customer count adjustments are common for most CIS conversions. Five Point Partners, LLC advised the FEU that even when a utility converts from a billing system of a relatively recent vintage to one of a quite recent vintage, as the FEU have done in the past few months, the actual data structures of the two systems will likely not be the same, and there will not necessarily be a "one-to-one" mapping between the Customer, Account, and sub-account objects in both systems. In each case, the changes in reported counts do not reflect a difference in the utility's actual delivery of service but do reflect changes in the structure of its systems and consolidation of formerly separate data elements in these systems.

Although common, the FEU did not identify that this adjustment would occur with the new CIS as part of its CCE CPCN filing because, until the definition of a customer in the new

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[3] TGVI is the acronym for Terasen Gas (Vancouver Island) Inc., the previous name for FEVI

[4] Terasen Gas (Vancouver Island) Inc. 2006 Settlement Update of its 2006-2007 Revenue Requirement Application Negotiated Settlement Agreement

system was determined, the existence of an adjustment was not known. And, until the development of the new CIS had progressed to the point where live test data was run through it, the magnitude of any adjustment could not even be estimated. Finally, as noted, the adjustment does not impact the FEU's historical results or rate forecasts.

2. The Adjustment does not affect Historical Results or Rate Forecasts

Historical Results

Historically, both the total volumes and revenues reported (and forecast) remain valid. Total volumes are valid since they are based upon metered consumption. And, as revenues are based upon total volumes, they also remain valid. However, if it was possible to restate historical customer counts to conform to the new definition, then the number of customers reported would decrease and average use rates would correspondingly increase[5].

FEI also notes that the method used to count customers throughout the Performance Based Ratemaking ("PBR") period was consistent, such that the starting customer count for the formula-driven inputs to the delivery rates during that time was determined using the same methodology as the customer counts during the entire PBR period. Therefore, the resulting allowed O&M and capital amounts were appropriately determined.

Rate Forecasts for 2012 and 2013

The forecasting methodology used by the FEU for 2012 and 2013 was to calculate the opening volumes which are unaffected by the adjustment (existing customers and use rates), and then add to this the forecast of the customer additions and multiply the customer additions by the forecasted use rate. Although the magnitude of the customer count adjustment could not be known until after the evidentiary record was closed in the FEU 2012-2013 Revenue Requirements Application ("RRA"), in hindsight we can determine that the forecasted use rate was slightly understated for the 2012 and 2013 customer additions. The associated incremental volumes are not material, and any resulting delivery margin variance[6] will be captured in the RSAM account for FEI (including the Fort Nelson region) and FEW, and in the Rate Stabilization Deferral Account for FEVI. The incremental volume adjustment does not affect the approved 2012-2013 delivery rates.

3. Future Commission Filings

Customer Count Adjustment in the RSAM

The RSAM, originally approved by Commission Order No. G-59-94, and subsequently approved for Fort Nelson through Commission Order No. G-17-04 and Whistler through Commission Order No. G-138-10, is a mechanism that stabilizes the Utilities' delivery margin revenue from the residential and commercial customer classes in FEI and all customers in FEW and Fort Nelson. The RSAM enables the Companies to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate

[5] The actual use rate is calculated as total volumes divided by number of customers.
[6] Estimated at $83,000 for FEI, $70,000 for FEVI and $1,200 for FEW

class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to the amount customers would have paid based on forecast use. If actual use is less than forecast, the RSAM deferral account is charged for the variance in use times the delivery rate and the RSAM revenue is credited. Conversely, if actual use is greater than forecast, the RSAM deferral account is credited and the RSAM revenue is decreased. Three important inputs to the RSAM deferral account additions are the number of customers, the approved use rate and the actual use rate (volumes divided by number of customers).

For 2012 and 2013, the reported customer counts from the CIS will be lower and the calculated use rates will be higher, than what would have been reported under the previous CIS. However, the approved use rates were calculated based on the previous higher customer counts. To avoid recording an incorrect amount in the RSAM account, the customer counts for 2012 and 2013 will be restated for the opening customer count adjustment described above (in effect removing the adjustment so that the calculation continues with the use rates and customer counts both reflecting the previous methodology).

Future Filings

For all reporting, 2012 and forward, the January 1, 2012 customer count adjustment will be reflected, which means that customer counts and use rates will not be consistent with years prior to 2012 (customer counts will be lower and use rates will be higher). This will be apparent in tables and figures that show historical and forecast information, and associated trends.

The demand forecasts included in rate applications for 2014 forward will use the revised higher use rates and lower customer counts.

If you require further information or have any questions regarding this submission, please contact the undersigned.

Yours very truly,

On behalf of the FORTISBC ENERGY UTILITIES

Original signed:

Diane Roy

cc (email only): FEU 2012-2013 RRA Registered Parties

Appendix E5

DIRECTIVE NO. 1 CUSTOMER ADDITION VARIANCE

Customer Addition Variance

Table of Contents

1. SUMMARY

In this Appendix, FEI provides a response to Directive #1 in the 2012-2013 RRA Decision related to the demand forecast. Directive 1 states:

> *"The Commission Panel agrees with the BCOAPO that it would be of value for the FEU to file a financial analysis of the impact of variances in the forecast of customer additions on all rate classes when they file their next RRA and the FEU are directed to do so."*

In response to Directive #1, FEI concludes the following based on the analysis in this Appendix.

1. For residential and commercial customers, any variation in the customer demand from what has been forecast in rates has no impact on the gross margin earned from a new customer because of the RSAM mechanism. See Section 4 for the supporting analysis.
2. Due to the main extension (MX) test and resulting CIAC and also the Service Line Cost Allowance (SLCA) that is applicable to residential and small commercial customers, capital cost exposure to the rate base is limited when adding customers. See Section 5 for the supporting analysis.
3. There is a relatively small variance on the earned return from the effect of the incremental capital cost of adding or not adding a customer. In all scenarios there is a positive impact on the earned return when adding a customer that was not forecast and conversely a negative impact to earned return when not adding a customer that was forecast. See Section 6 for the supporting analysis
4. Any increase or decrease in earned return is temporary until the next time delivery rates are reset.
5. There is no consistent historical experience of over or under forecasting customer additions. See Section 7 for the supporting analysis.
6. The historical 10 year average would suggest it is more likely for the utility to experience a slight decrease in earned return (approximately $227 thousand) compared to the forecast due to actual customer additions being, in general, less than forecast. See Section 8 for the supporting analysis.
7. In all cases, when adding customers, there is a positive effect on the incremental delivery margin and earned return and these additions will help to offset future rate increases when delivery rates are next reset.

2. APPROACH TO ANALYSIS

The approach taken by FEI to this analysis was to assess the customer classes that are primarily associated with the customer addition variances, to approximate the variability in the use per customer from a new customer and then to approximate the variability in incremental capital, cost of service and the resulting impact on earned return.

Although the number of permutations from variances in customer additions and how they could impact the Company financially are infinite, for purposes of this analysis, FEI has calculated 48 financial impact scenarios using combinations of the following:

Four Customer Classes

Customer classes included were Residential (Rate Schedule 1), Small Commercial (Rate Schedule 2), and Large Commercial (Rate Schedule 3 – Sales and Rate Schedule 23 – T-Service). It is these rate classes that have the greatest variability in forecast additions versus actual additions. Since other rate schedules have a much smaller number of customers whereby the expected variance in customer additions would be zero or a very small number, they have been excluded from this analysis. In addition, there are no forecast customer additions for the industrial rate schedules in the forecast period.

Three Use Per Customer (UPC) Scenarios

Low, average and high volume UPC scenarios were explored for each customer class. Average UPC was from the 2013 approved forecast. The impact of the three UPC scenarios is discussed in Section 4 of this Appendix.

Four Capital Cost Scenarios

Low, average and high cost possibilities were explored, as well as a scenario where no main extension is required to service the customer. The impact of the capital cost scenarios is discussed in Section 5 of this Appendix.

3. LIST OF ASSUMPTIONS

For the financial impact analyses the following has been assumed:

1. Customer additions occur mid-way through the first year (2013) of the analysis Period and each analysis assumes the customer would remain a customer in the following year.
2. Overhead capitalization charged to plant additions is 27% as is used in FEI's MX Test.
3. Depreciation and Negative Salvage rates are those approved in the 2012-2013 RRA.
4. Annual overhead capitalization from O&M expense is 14% as approved in the 2012-2013 RRA.
5. Low volume UPC was based on the 2012 actual data using a midpoint of the lowest 30 percent, and similarly the high volume UPC was based on the midpoint of the highest 30 percent. Average UPC was from the 2013 approved UPC.

6. Income tax rate is 25 percent; for income tax purposes, capital additions are added to Class 51 with a CCA rate of 6 percent; 6/14th of overhead capitalized from O&M expense are expensed for determining taxable income as approved in the 2012-2013 RRA. Utility interest expense is based on the capital structure and cost of debt approved by the Commission in Order G-75-13.
7. Revenue and margin calculations are based on the approved tariffs as of January 1, 2013 for residential, small commercial and large commercial customers.
8. Incremental operating and maintenance cost is as used in FEI's MX Test.
9. Service Line Cost Allowance (SLCA), limiting maximum service line costs for new Residential and Small Commercial service is from FEI's tariff for 'Other than a duplex' at $1,535.00. Low cost is the average cost / meter multiplied by the midpoint of the lowest 1/3rd distance of service line and the high cost is the midpoint for the longest service lines installed, taking into consideration the SLCA.
10. The distance to reach the next customer on a main extension is 10.7 meters. Estimation of Low, Average, and High Main Extension cost was based on 2012 Actual main extensions for 2" and 4" diameter installations.
11. Meter and Instrument costs were based on incremental costs for the various types of meter sets used by residential and commercial customers. Low cost is the average lowest cost of 1/3 of the meter sets and the high cost is the average of the highest 1/3 of the meter sets.

4. UPC IMPACT ON REVENUE, RSAM AND GROSS MARGIN

The following Table E5-1 shows the various UPC scenarios that have been used to derive the impact of customer addition variances on revenue, RSAM and gross margin.

Table E5-1: UPC Scenarios for Rate Schedules

Particulars		Rate Schedules 1	2	3	23
Use per Customer (GJ)	Low	55.0	56.5	2,000.0	2,764.5
	Average	89.9	306.4	3,316.0	4,927.0
	High	142.0	942.5	5,073.0	7,187.8

Table E5-2 below shows the gross margin impact of the various UPC scenarios for each of the four customer classes. For each customer class, the line called "Gross Margin" shows that the gross margin recorded is not affected by the UPC within a customer class. This is because the RSAM captures the margin impact of the difference in actual versus forecast average use per customer (it adjusts the revenues to yield the forecast margin). Note that the difference in the results between 2013 and 2014 as shown in the table below is due to a mid-year addition assumption for 2013 versus a full year in 2014.

Table E5-2: Revenue, RSAM Revenue, & Gross Margin for Three UPC Scenarios

Particulars	2013 Low UPC	2014 Low UPC	2013 Average UPC	2014 Average UPC	2013 High UPC	2014 High UPC
Rate Schedule 1 - Residential						
Annual Use / Customer (GJ)	27.5	55.0	45.0	89.9	71.0	142.0
Forecast Use / Customer (GJ)	45.0	89.9	45.0	89.9	45.0	89.9
Basic Charge $ / Day			$0.3890			
Delivery Charge $ / GJ			$3.790			
Midstream Cost Recovery $ / GJ			$1.274			
Commodity Cost Recovery $ / GJ			$2.977			
Revenue	$ 292	$ 584	$ 432	$ 865	$ 642	$ 1,284
RSAM Revenue	66	132	-	-	(99)	(197)
Cost of Gas	(117)	(234)	(191)	(382)	(302)	(604)
Gross Margin	$ 241	$ 483	$ 241	$ 483	$ 241	$ 483
Rate Schedule 2 - Small Commercial						
Annual Use / Customer (GJ)	28.2	56.5	153.2	306.4	471.3	942.5
Forecast Use / Customer (GJ)	153.2	306.4	153.2	306.4	153.2	306.4
Basic Charge $ / Day			$0.8161			
Delivery Charge $ / GJ			$3.099			
Midstream Cost Recovery $ / GJ			$1.265			
Commodity Cost Recovery $ / GJ			$2.977			
Revenue	$ 356	$ 712	$ 1,274	$ 2,547	$ 3,609	$ 7,217
RSAM Revenue	387	775	-	-	(986)	(1,971)
Cost of Gas	(120)	(240)	(650)	(1,300)	(1,999)	(3,998)
Gross Margin	$ 624	$ 1,247	$ 624	$ 1,247	$ 624	$ 1,247
Rate Schedule 3 - Large Commercial - Sales						
Annual Use / Customer (GJ)	1,000.0	2,000.0	1,658.0	3,316.0	2,536.5	5,073.0
Forecast Use / Customer (GJ)	1,658.0	3,316.0	1,658.0	3,316.0	1,658.0	3,316.0
Basic Charge $ / Day			$4.3538			
Delivery Charge $ / GJ			$2.617			
Midstream Cost Recovery $ / GJ			$0.999			
Commodity Cost Recovery $ / GJ			$2.977			
Revenue	$ 7,388	$ 14,775	$ 11,726	$ 23,452	$ 17,518	$ 35,036
RSAM Revenue	1,722	3,444	-	-	(2,299)	(4,598)
Cost of Gas	(3,976)	(7,952)	(6,592)	(13,184)	(10,085)	(20,170)
Gross Margin	$ 5,134	$ 10,267	$ 5,134	$ 10,267	$ 5,134	$ 10,267
Rate Schedule 23 - Large Commercial - T-Service						
Annual Use / Customer (GJ)	1,382.3	2,764.5	2,463.5	4,927.0	3,593.9	7,187.8
Forecast Use / Customer (GJ)	2,463.5	4,927.0	2,463.5	4,927.0	2,463.5	4,927.0
Basic Charge $ / Month			$132.52			
Delivery Charge $ / GJ			$2.617			
Administrative Charge $ / Month			$78.00			
Revenue	$ 4,881	$ 9,761	$ 7,710	$ 15,420	$ 10,668	$ 21,337
RSAM Revenue	2,830	5,659	-	-	(2,958)	(5,916)
Gross Margin	$ 7,710	$ 15,420	$ 7,710	$ 15,420	$ 7,710	$ 15,420

Based on this analysis, FEI concludes that for residential and commercial customers, any variation in the customer demand from what has been forecast in rates has no impact on the gross margin earned from a new customer because of the RSAM mechanism.

5. CAPITAL COST ASSOCIATED WITH CUSTOMER ATTACHMENTS

In this section, FEI reviews the four capital cost scenarios used in the analysis for attaching a customer; these include the low, average cost, and high cost estimate for a mains extension to reach the next customer, service line and meter. One additional variation was to consider what the capital cost would be when a main extension is not required (called an "in-fill" customer addition). The following table shows the low, average and high capital cost to attach a new customer using the assumptions as described in Section 3.

Table E5-3: Incremental Capital Spend: Low, Average & High

Particulars		Rate Schedules 1	2	3	23
Mains Extension	Low	$ 405	$ 405	$ 405	$ 405
	Average	$ 710	$ 710	$ 710	$ 710
	High	$ 1,381	$ 1,381	$ 1,381	$ 1,381
Service Line	Low	$ 599	$ 552	$ 715	$ 715
	Average	$ 1,152	$ 1,535	$ 5,665	$ 5,665
	High	$ 1,535		$ 6,866	$ 6,866
Meters & Instruments	Low	$ 128	$ 128	$ 3,544	$ 5,638
	Average	$ 128	$ 199	$ 4,748	$ 7,245
	High	$ 166	$ 2,979	$ 8,726	$ 14,291

Main extension costs are not tracked to specific rate classes as a variety of different types of customers can be served from a main extension. However, the location of the main can significantly affect the cost of a main extension. For a discussion on factors affecting capital costs of attaching customers please refer Section C4.5.2 for Mains, Section C4.5.3 for Services and Section C4.5.4 for New Meters.

For this financial analysis, the Low Capital scenario was the low cost estimate for each of Mains, Service Line, and Meters & Instruments. Similarly, the same was applied for the Average Capital cost and the High Capital Cost.

Two pertinent constraints limit the amount of capital cost FEI will spend when attaching customers. For Residential and Small Commercial customers, the Service Line Cost Allowance limits the maximum capital cost exposure to $1,535 for "Other Than a Duplex". When a service line cost exceeds the SLCA, the customer must make a CIAC for the difference between the actual cost of the service line and the SLCA. A CIAC will also be required in those instances when the cost of the pathway requested by the customer for the service line is a higher cost than the utility's lower cost preferred choice.

A second constraint is that a CIAC will be required when the total cost of the main, service line and meter exceeds what the MX test will support. The following table shows the maximum capital spend (before applying capitalized overhead) that the MX test can support before a CIAC is required for the Rate Schedules listed in the above table associated with the various annual UPC (UPC from Table E5-1).

Table E5-4: UPC & Maximum Capital Spend by Rate Schedule

		Rate Schedules			
Particulars		1	2	3	23
Use per Customer (GJ)	Low	55.0	56.5	2,000.0	2,764.5
	Average	89.9	306.4	3,316.0	4,927.0
	High	142.0	942.5	5,073.0	7,187.8
Maximum Capital Spend excl. 27% Overhead & at 0.8 PI Threshold					
	Low	$ 2,680	$ 3,930	$ 62,000	$ 80,600
	Average	$ 3,940	$ 11,070	$ 93,500	$131,500
	High	$ 5,820	$ 29,300	$135,000	$184,600

In the scenarios considered, a CIAC would be required from residential and small commercial customers who have a low demand (UPC) but have a high capital cost to attach, as shown in Table E5-5 below.

Table E5-5: Examples of CIAC Requirement

Residential Low Demand (UPC), with high Capital Cost	
Main	$ 1,381
Service Line	1,535
Meter	166
Total	3,082
Maximum Capital Spend	2,680
CIAC Requirement	$ 402
Small Commercial Low Demand (UPC), with High Capital Cost	
Main	$ 1,381
Service Line	1,535
Meter	2,979
Total	5,895
Maximum Capital Spend	3,930
CIAC Requirement	$ 1,965

Customers with average or high demand would typically not be required to make a CIAC.

6. EARNED RETURN IMPACT OF ONE CUSTOMER ADDITION

In the utility's cost of service, there are line items that do vary with capital cost, i.e. depreciation expense, negative salvage provision (which is included in the amortization expense of deferred charges), property taxes and income taxes and utility debt financing costs. In the short term these variances would have an impact on the earned return but only until rates affecting the margin are reset, at which point the actual costs become embedded in the rate base and cost of service.

The following Table E5-6 summarizes the potential impact on earned return from the various capital spend and deferred RSAM from various UPC, totalling 48 scenarios (4 rate schedules, 3 UPCs, and 4 capital spend scenarios).

Table E5-6 Summary of Impact on Earned Return (48 Scenarios)

Particulars	Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014	Average 2014
Rate Schedule 1 - Residential									
Low UPC	$ 169	$ 281	$ 167	$ 260	$ 167	$ 241	$ 160	$ 253	$ 259
Average UPC	$ 169	$ 280	$ 166	$ 259	$ 166	$ 238	$ 160	$ 252	$ 258
High UPC	$ 168	$ 279	$ 166	$ 258	$ 166	$ 237	$ 159	$ 251	$ 256
Rate Schedule 2 - Small Commercial									
Low UPC	$ 456	$ 859	$ 449	$ 820	$ 380	$ 666	$ 370	$ 671	$ 754
Average UPC	$ 455	$ 854	$ 448	$ 815	$ 374	$ 652	$ 368	$ 666	$ 747
High UPC	$ 451	$ 840	$ 444	$ 801	$ 371	$ 638	$ 364	$ 652	$ 733
Rate Schedule 3 - Large Commercial - Sales									
Low UPC	$ 3,734	$ 7,416	$ 3,670	$ 7,186	$ 3,556	$ 6,917	$ 3,550	$ 6,931	$ 7,112
Average UPC	$ 3,727	$ 7,392	$ 3,664	$ 7,162	$ 3,550	$ 6,893	$ 3,543	$ 6,907	$ 7,088
High UPC	$ 3,719	$ 7,359	$ 3,655	$ 7,129	$ 3,541	$ 6,861	$ 3,535	$ 6,875	$ 7,056
Rate Schedule 23 - Large Commercial - T-Service									
Low UPC	$ 5,613	$ 11,179	$ 5,538	$ 10,926	$ 5,340	$ 10,485	$ 5,333	$ 10,499	$ 10,772
Average UPC	$ 5,602	$ 11,139	$ 5,527	$ 10,886	$ 5,329	$ 10,445	$ 5,323	$ 10,459	$ 10,732
High UPC	$ 5,591	$ 11,097	$ 5,516	$ 10,845	$ 5,318	$ 10,404	$ 5,311	$ 10,418	$ 10,691

The above table shows that an extra customer addition for the residential class only adds approximately $258 on average to the Company's earned return (debt and equity) with a range of approximately $240 to $280; conversely, if the customer addition is lower than forecast the earnings would be lower by $258. For a small commercial customer the earned return impact ranges from approximately $650 - $860 with an average of $747, for a large commercial sales customer the earned return impact ranges from approximately $6,900 to $7,400 with an average of $7,088, and for a large commercial T-service customer the earned return ranges from approximately $10,400 to $11,200 with an average of $10,732. The tables provided in Section 8 that follows show the calculations of the earned return amounts that are summarized in Table E4-6 above.

To determine whether these earned return impacts have historically favoured the utility, the next step is to look at the historical record to see if there is a pattern to customer addition variances, and, using the earned return impacts above, extrapolating to determine the hypothetical total impact of these variances.

7. HISTORICAL COMPARISON OF ACTUAL VERSUS FORECAST NET CUSTOMER ADDITIONS BY CUSTOMER CLASS

Table E5-7 below shows the historical variances in the forecast versus actual customer additions for Rate Schedule 1, 2, 3 and 23. Based on the information in this table, FEI has concluded that there is no consistent historical experience of over or under forecasting customer additions.

Table E5-7: Customer Net Additions: Actual Versus Forecast

	Residential			Small Commercial		
Year	Actual	Forecast	Variance	Actual	Forecast	Variance
2003	6,306	6,687	(381)	(703)	(590)	(114)
2004	10,716	8,000	2,716	836	463	373
2005	11,427	9,652	1,775	1,203	375	828
2006	9,595	12,204	(2,609)	553	622	(69)
2007	12,003	12,764	(761)	1,064	218	847
2008	7,959	11,098	(3,139)	1,122	626	496
2009	4,822	8,012	(3,190)	285	601	(316)
2010	6,824	4,777	2,047	42	713	(671)
2011	4,994	4,983	11	409	750	(341)
2012	4,475	6,507	(2,032)	325	49	276
Total 10 Year Variance			(5,563)			1,309
Average Variance			(556)			131

	Large Commercial - Sales			Large Commercial - T-Service			Total 3/23
Year	Actual	Forecast	Variance	Actual	Forecast	Variance	Variance
2003	(46)	(38)	(7)	(11)	(9)	(2)	(9)
2004	(278)	30	(308)	198	7	191	(117)
2005	(354)	16	(370)	119	110	9	(361)
2006	48	(142)	190	57	9	48	238
2007	(69)	14	(83)	97	3	94	11
2008	169	8	161	3	70	(67)	94
2009	(28)	8	(36)	42	67	(25)	(61)
2010	41	101	(60)	58	9	49	(11)
2011	(19)	108	(127)	27	9	18	(109)
2012	(144)	40	(184)	91	60	31	(153)
Total 10 Year Variance			(824)			345	(479)
Average Variance			(82)			38	(48)

For residential customers, the variance in customer additions over the past 10 years has averaged 556 actual additions less than forecast (with a range of 3,190 less than forecast to

2,716 more than forecast). There is no consistent direction of the variance error, as there have been both positive and negative variances over the past ten years.

For small commercial customers, the variance in customer additions over the past 10 years has averaged 131 actual additions more than forecast (with a range of 671 less than forecast to 847 greater than forecast).

For large commercial (Rate Schedule 3) customers, the variance in customer additions over the past 10 years has averaged 82 actual additions less than forecast (with a range of 370 less than forecast to 190 greater than forecast).

For large commercial (Rate Schedule 23) customers, the variance in customer additions over the past 10 years has averaged 38 actual additions greater than forecast (with a range of 67 less than forecast to 191 greater than forecast).

As can be seen in the following table summarizing the forecast and actual customer additions variance, in only two years were all customer classes' additions variances unfavourable, 2003 and 2009. All other years were a mix of favourable and unfavourable variances between the rate classes.

Table E5-8: Sum of Customer Additions Variances

		Commerical			
Year	Residential	Small	Large		
	1	2	3	23	Total
2003	(381)	(114)	(7)	(2)	(504)
2004	2,716	373	(308)	191	2,972
2005	1,775	828	(370)	9	2,242
2006	(2,609)	(69)	190	48	(2,440)
2007	(761)	847	(83)	94	96
2008	(3,139)	496	161	(67)	(2,549)
2009	(3,190)	(316)	(36)	(25)	(3,567)
2010	2,047	(671)	(60)	49	1,365
2011	11	(341)	(127)	18	(439)
2012	(2,032)	276	(184)	31	(1,909)
Total 10 Year Variance					(4,733)
Average Variance					(473)

Combined, the variance in customer additions over the past 10 years has averaged 473 actual additions less than forecast (with a range of 3,567 less than forecast to 2,972 greater than forecast) with no consistent experience of over or under forecasting customer additions.

The actual additions in the tables above do not take into consideration the number of customers that are switches between rate classes, i.e. between Rate Schedules 2 and 3 or 23, and between 3 and 23. However, for the commercial customers, in total the ten year average actual additions have exceeded forecast additions by 83.

8. AVERAGE EARNED RETURN IMPACT TO FEI OF CUSTOMER VARIANCES

The following Table E5-9 shows the potential impact on earned return from multiplying the average customer addition variance for each customer class (Table E5-7) times the highest earned return (Table E5-6). This result provides an expected average **maximum** impact on Earned Return of approximately $227 thousand.

Table E5-9: Maximum Incremental Earned Return Impact from Average Customer Variance

Sum of All Rate Classes Customer Additions Variance Impact on Earned Return		
Average Customer Additions Variance	$	(226,734)
Rate Schedule 1 - Residential		
Average Customer Addition Variance from Forecast		(556)
x Maximum Earned Return Impact per Customer	$	281
Average Customer Addition Impact on Earned Return	$	(156,471)
Rate Schedule 2 - Small Commercial		
Average Customer Addition Variance from Forecast		131
x Maximum Earned Return Impact per Customer	$	859
Average Customer Addition Impact on Earned Return	$	112,442
Rate Schedule 3 - Large Commercial - Sales		
Average Customer Addition Variance from Forecast		(82)
x Maximum Earned Return Impact per Customer	$	7,416
Average Customer Addition Impact on Earned Return	$	(611,343)
Rate Schedule 23 - Large Commercial - T-Service		
Average Customer Addition Variance from Forecast		38
x Maximum Earned Return Impact per Customer	$	11,179
Average Customer Addition Impact on Earned Return	$	428,638

The average value on the customer additions variance impact over the ten year period would be approximately $227 thousand (Table E5-9) reduction to earned return using the assumptions embedded in this analysis, assuming that the customer addition variance was being impacted by the cost of the customer connection that would have contributed the **highest** incremental earned return. Under either a low earned return or an average earned return scenario for a particular rate class, this amount would be reduced.

9. EARNED RETURN CALCULATION TABLES

The following tables (E5-10 Rate Schedule 1, E5-11 Rate Schedule 2, E5-12 Rate Schedule 3 and E5-13 Rate Schedule 23) show the effect on gross margin (as described in Section 4) combined with the impact on depreciation expense, negative salvage provision, income tax expense and ultimately on earned return from the low capital expenditure, average capital expenditure and high capital expenditure (with and without a main extension) scenarios. The operating and maintenance expense used in this analysis is the incremental cost that the utility uses in its main extension test and the $25 in other revenue is the Application Fee for a new customer.

Table E5-10: Rate Schedule 1 - Residential

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 1 - Low UPC									
Gross Margin		241	483	241	483	241	483	241	483
Operating & Maintenance Expense		41	81	41	81	41	81	41	81
Overhead Capitalized @	14%	(6)	(11)	(6)	(11)	(6)	(11)	(6)	(11)
Net O&M		35	70	35	70	35	70	35	70
Property Taxes									
General, School & Other	1.93%	-	25	-	46	-	71	-	38
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	25	-	46	-	71	-	38
Depreciation Expense		15	30	24	48	28	57	25	51
Negative Salvage Expense		5	10	9	19	13	27	11	22
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		211	348	198	301	190	258	195	303
Income Tax Expense		43	67	32	40	23	17	35	50
Earned Return		$ 169	$ 281	$ 167	$ 260	$ 167	$ 241	$ 160	$ 253

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 1 - Average UPC									
Gross Margin		241	483	241	483	241	483	241	483
Operating & Maintenance Expense		41	81	41	81	41	81	41	81
Overhead Capitalized @	14%	(6)	(11)	(6)	(11)	(6)	(11)	(6)	(11)
Net O&M		35	70	35	70	35	70	35	70
Property Taxes									
General, School & Other	1.93%	-	25	-	46	-	71	-	38
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	25	-	46	-	71	-	38
Depreciation Expense		15	30	24	48	34	69	25	51
Negative Salvage Expense		5	10	9	19	13	27	11	22
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		211	348	198	301	184	246	195	303
Income Tax Expense		43	68	32	41	18	8	36	51
Earned Return		$ 169	$ 280	$ 166	$ 259	$ 166	$ 238	$ 160	$ 252

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 1 - High UPC									
Annual Use / Customer (GJ)		71.0	142.0	71.0	142.0	71.0	142.0	71.0	142.0
Forecast Use / Customer (GJ)		45.0	89.9	45.0	89.9	45.0	89.9	45.0	89.9
Application Fee		$ 25.00		$ 25.00		$ 25.00		$ 25.00	
Basic Charge $ / Day		$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890	$ 0.3890
Basic Charge $ / Month									
Delivery Charge $ / GJ		$ 3.790	$ 3.790	$ 3.790	$ 3.790	$ 3.790	$ 3.790	$ 3.790	$ 3.790
Administrative Charge $ / Month									
Midstream Cost Recovery $ / GJ		$ 1.274	$ 1.274	$ 1.274	$ 1.274	$ 1.274	$ 1.274	$ 1.274	$ 1.274
Commodity Cost Recovery $ / GJ		$ 2.977	$ 2.977	$ 2.977	$ 2.977	$ 2.977	$ 2.977	$ 2.977	$ 2.977
Revenue		$ 642	$ 1,284	$ 642	$ 1,284	$ 642	$ 1,284	$ 642	$ 1,284
RSAM Revenue		(99)	(197)	(99)	(197)	(99)	(197)	(99)	(197)
Cost of Gas		(302)	(604)	(302)	(604)	(302)	(604)	(302)	(604)
Gross Margin		241	483	241	483	241	483	241	483
Operating & Maintenance Expense		41	81	41	81	41	81	41	81
Overhead Capitalized @	14%	(6)	(11)	(6)	(11)	(6)	(11)	(6)	(11)
Net O&M		35	70	35	70	35	70	35	70
Property Taxes									
General, School & Other	1.93%	-	25	-	46	-	71	-	38
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	25	-	46	-	71	-	38
Depreciation Expense		15	30	24	48	34	69	25	51
Negative Salvage Expense		5	10	9	19	13	27	11	22
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		211	348	198	301	184	246	195	303
Income Tax Expense		43	69	32	43	18	9	36	52
Earned Return		$ 168	$ 279	$ 166	$ 258	$ 166	$ 237	$ 159	$ 251

Table E5-11: Rate Schedule 2 - Small Commercial

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 2 - Low UPC									
Gross Margin		624	1,247	624	1,247	624	1,247	624	1,247
Operating & Maintenance Expense		42	84	42	84	42	84	42	84
Overhead Capitalized @	14%	(6)	(12)	(6)	(12)	(6)	(12)	(6)	(12)
Net O&M		36	72	36	72	36	72	36	72
Property Taxes									
General, School & Other	1.93%	-	23	-	55	-	71	-	38
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	23	-	55	-	71	-	38
Depreciation Expense		14	29	31	63	112	224	131	263
Negative Salvage Expense		5	10	12	24	20	41	18	36
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		593	1,113	569	1,033	480	839	463	839
Income Tax Expense		137	254	120	213	101	173	94	168
Earned Return		$ 456	$ 859	$ 449	$ 820	$ 380	$ 666	$ 370	$ 671

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 2 - Average UPC									
Gross Margin		624	1,247	624	1,247	624	1,247	624	1,247
Operating & Maintenance Expense		42	84	42	84	42	84	42	84
Overhead Capitalized @	14%	(6)	(12)	(6)	(12)	(6)	(12)	(6)	(12)
Net O&M		36	72	36	72	36	72	36	72
Property Taxes									
General, School & Other	1.93%	-	23	-	55	-	71	-	38
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	23	-	55	-	71	-	38
Depreciation Expense		14	29	31	63	140	281	131	263
Negative Salvage Expense		5	10	12	24	20	41	18	36
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		593	1,113	569	1,033	452	782	463	839
Income Tax Expense		139	260	121	218	78	130	95	173
Earned Return		$ 455	$ 854	$ 448	$ 815	$ 374	$ 652	$ 368	$ 666

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 2 - High UPC									
Gross Margin		624	1,247	624	1,247	624	1,247	624	1,247
Operating & Maintenance Expense		42	84	42	84	42	84	42	84
Overhead Capitalized @	14%	(6)	(12)	(6)	(12)	(6)	(12)	(6)	(12)
Net O&M		36	72	36	72	36	72	36	72
Property Taxes									
General, School & Other	1.93%	-	23	-	55	-	71	-	38
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	23	-	55	-	71	-	38
Depreciation Expense		14	29	31	63	140	281	131	263
Negative Salvage Expense		5	10	12	24	20	41	18	36
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		593	1,113	569	1,033	452	782	463	839
Income Tax Expense		142	274	125	232	81	144	99	187
Earned Return		$ 451	$ 840	$ 444	$ 801	$ 371	$ 638	$ 364	$ 652

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2 **Table E5-12: Rate Schedule 3 - Large Commercial – Sales**

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 3 - Low UPC									
Gross Margin		5,134	10,267	5,134	10,267	5,134	10,267	5,134	10,267
Operating & Maintenance Expense		66	131	66	131	66	131	66	131
Overhead Capitalized @	14%	(9)	(18)	(9)	(18)	(9)	(18)	(9)	(18)
Net O&M		56	113	56	113	56	113	56	113
Property Taxes									
General, School & Other	1.93%	-	27	-	156	-	202	-	168
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	27	-	156	-	202	-	168
Depreciation Expense		145	290	254	508	423	846	414	828
Negative Salvage Expense		14	29	52	103	71	142	68	137
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		4,943	9,808	4,797	9,387	4,608	8,965	4,620	9,021
Income Tax Expense		1,209	2,392	1,127	2,201	1,052	2,048	1,070	2,090
Earned Return		$ 3,734	$ 7,416	$ 3,670	$ 7,186	$ 3,556	$ 6,917	$ 3,550	$ 6,931

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Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 3 - Average UPC									
Gross Margin		5,134	10,267	5,134	10,267	5,134	10,267	5,134	10,267
Operating & Maintenance Expense		66	131	66	131	66	131	66	131
Overhead Capitalized @	14%	(9)	(18)	(9)	(18)	(9)	(18)	(9)	(18)
Net O&M		56	113	56	113	56	113	56	113
Property Taxes									
General, School & Other	1.93%	-	27	-	156	-	202	-	168
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	27	-	156	-	202	-	168
Depreciation Expense		145	290	254	508	423	846	414	828
Negative Salvage Expense		14	29	52	103	71	142	68	137
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		4,943	9,808	4,797	9,387	4,608	8,965	4,620	9,021
Income Tax Expense		1,215	2,416	1,133	2,225	1,059	2,072	1,077	2,114
Earned Return		$ 3,727	$ 7,392	$ 3,664	$ 7,162	$ 3,550	$ 6,893	$ 3,543	$ 6,907

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 3 - High UPC									
Gross Margin		5,134	10,267	5,134	10,267	5,134	10,267	5,134	10,267
Operating & Maintenance Expense		66	131	66	131	66	131	66	131
Overhead Capitalized @	14%	(9)	(18)	(9)	(18)	(9)	(18)	(9)	(18)
Net O&M		56	113	56	113	56	113	56	113
Property Taxes									
General, School & Other	1.93%	-	27	-	156	-	202	-	168
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	27	-	156	-	202	-	168
Depreciation Expense		145	290	254	508	423	846	414	828
Negative Salvage Expense		14	29	52	103	71	142	68	137
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		4,943	9,808	4,797	9,387	4,608	8,965	4,620	9,021
Income Tax Expense		1,224	2,448	1,142	2,258	1,068	2,104	1,085	2,147
Earned Return		$ 3,719	$ 7,359	$ 3,655	$ 7,129	$ 3,541	$ 6,861	$ 3,535	$ 6,875

Table E5-13: Rate Schedule 23 - Large Commercial – T-Service

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 23 - Low UPC									
Gross Margin		7,710	15,420	7,710	15,420	7,710	15,420	7,710	15,420
Operating & Maintenance Expense		66	131	66	131	66	131	$ 65.50	131.0
Overhead Capitalized @	14%	(9)	(18)	(9)	(18)	(9)	(18)	(9.2)	(18.3)
Net O&M		56	113	56	113	56	113	56.3	112.7
Property Taxes									
General, School & Other	1.93%	-	27	-	156	-	202	-	168
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	27	-	156	-	202	-	168
Depreciation Expense		224	448	348	696	632	1,265	623	1,247
Negative Salvage Expense		20	39	58	116	85	170	82	165
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		7,435	14,793	7,273	14,340	6,962	13,671	6,973	13,728
Income Tax Expense		1,822	3,614	1,735	3,414	1,622	3,186	1,640	3,229
Earned Return		$ 5,613	$ 11,179	$ 5,538	$ 10,926	$ 5,340	$ 10,485	$ 5,333	$ 10,499

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 23 - Average UPC									
Gross Margin		7,710	15,420	7,710	15,420	7,710	15,420	7,710	15,420
Operating & Maintenance Expense		66	131	66	131	66	131	66	131
Overhead Capitalized @	14%	(9)	(18)	(9)	(18)	(9)	(18)	(9)	(18)
Net O&M		56	113	56	113	56	113	56	113
Property Taxes									
General, School & Other	1.93%	-	27	-	156	-	202	-	168
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	27	-	156	-	202	-	168
Depreciation Expense		224	448	348	696	632	1,265	623	1,247
Negative Salvage Expense		20	39	58	116	85	170	82	165
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		7,435	14,793	7,273	14,340	6,962	13,671	6,973	13,728
Income Tax Expense		1,833	3,654	1,746	3,453	1,633	3,225	1,650	3,268
Earned Return		$ 5,602	$ 11,139	$ 5,527	$ 10,886	$ 5,329	$ 10,445	$ 5,323	$ 10,459

Particulars		Low Capital Spend 2013	Low Capital Spend 2014	Average Capital Spend 2013	Average Capital Spend 2014	High Capital Spend 2013	High Capital Spend 2014	In Fill High Capital Spend 2013	In Fill High Capital Spend 2014
Rate 23 - High UPC									
Gross Margin		7,710	15,420	7,710	15,420	7,710	15,420	7,710	15,420
Operating & Maintenance Expense		66	131	66	131	66	131	66	131
Overhead Capitalized @	14%	(9)	(18)	(9)	(18)	(9)	(18)	(9)	(18)
Net O&M		56	113	56	113	56	113	56	113
Property Taxes									
General, School & Other	1.93%	-	27	-	156	-	202	-	168
1% in lieu of	1%	-	-	-	-	-	-	-	-
Total Property Taxes		-	27	-	156	-	202	-	168
Depreciation Expense		224	448	348	696	632	1,265	623	1,247
Negative Salvage Expense		20	39	58	116	85	170	82	165
Other Revenue		(25)	-	(25)	-	(25)	-	(25)	-
Utility Income Before Income Tax		7,435	14,793	7,273	14,340	6,962	13,671	6,973	13,728
Income Tax Expense		1,844	3,695	1,757	3,495	1,644	3,267	1,662	3,310
Earned Return		$ 5,591	$ 11,097	$ 5,516	$ 10,845	$ 5,318	$ 10,404	$ 5,311	$ 10,418

Appendix F1

SHARED SERVICES AGREEMENTS

AMENDED AND RESTATED
SHARED SERVICES AGREEMENT

THIS AGREEMENT is made effective January 1, 2014 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly, Terasen Gas (Vancouver Island) Inc.)
16705 Fraser Highway,
Surrey, British Columbia
V4N 0E8

("FEVI")

AND:

FORTISBC ENERGY INC.
(formerly, Terasen Gas Inc.)
16705 Fraser Highway,
Surrey, British Columbia
V4N 0E8

("FEI")

WHEREAS

A. FEVI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of Vancouver Island and the Sunshine Coast (the "Facilities"); and

B. FEVI wishes to retain FEI to provide certain administrative and management services to it in respect to the ownership and common management of the operation of its transmission pipeline and distribution business and to receive services on an as and when required basis from third party contractors retained by FEI on the terms and conditions set out herein.

WITNESSES that, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the administrative and management services to be provided to FEVI by FEI and as more particularly described in Section 2.1 and any services provided on an as and when required basis under contract to FEI by a third party contractor which services are used by or provide benefit to FEVI.

1.2 Schedules

The following are the schedules attached to, and are incorporated by reference into, this Agreement:

Schedule "A"	Description of Services
Schedule "B"	Shared Service Fee

1.3 Interpretation

In and for the purpose of this Agreement,

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated "Article", "Section" or other subdivision is to the designated Article, Section or other subdivision of this Agreement,

3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

FEI hereby agrees to provide to FEVI the Services, including those administrative and management services described in Schedule "A".

2.2 No Obligation to Provide Additional Services

FEI shall not perform, and FEI shall have no obligation to perform, any services on behalf of FEVI in respect of the Facilities other than as set out in this Agreement or any similar agreement.

2.3 Consultation with FEVI

FEI will consult with FEVI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between FEI and FEVI. In performing the Services, FEI shall be an independent contractor. FEI employees shall not be considered employees of FEVI for any purpose.

2.5 Compliance

In performing the Services, FEI will comply with all Applicable Laws.

PART 3
COMPENSATION

3.1 Compensation for Services

FEVI agrees to pay compensation to FEI for the Services in accordance with this Section 3.1. FEVI agrees to pay to FEI the Shared Service Fee as set out in Schedule "B" for the administrative and management services provided by FEI employees and FEVI agrees to pay for the Services provided by a third party contractor retained by FEI, such portion of the amount invoiced by the third party contractor as is determined by FEI to be allocable to FEVI based on the nature and extent of third party services actually received in the applicable period. .

3.2 Amendment to Costs

The amounts set out in Schedule "B" may be amended from time to time by agreement between the parties to reflect any material change in the cost of providing the Services or in the business operations of FEVI.

3.3 Invoicing

FEI will invoice FEVI (the "Invoice") in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

(a) Except with respect to those portions of an Invoice which are the subject of a bona fide dispute between the parties, invoices shall be payable within thirty (30) days from the date of the invoice.

(b) Any amount to be remitted by FEVI to FEI and not remitted on or before the date on which it is due shall thereafter bear interest at an annual rate equal to the prime rate of interest of the Toronto-Dominion Bank (or its successor or permitted assign) (Toronto, Main Branch) plus one percent (1%) calculated daily from the date the amounts become due.

(c) FEI will prepare financial accounting of the actual costs and the allocated costs, and will make adjustments based on additional amount to be paid by FEVI or return an overpayment.

(d) Payments due and owing as a result of the accounting will be paid no later then the end of the first quarter of the following year.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by FEVI

Subject to Section 4.4, FEVI will indemnify, defend and hold harmless FEI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FEI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FEI.

4.2 Limitation of Liability of FEI

Neither FEI nor any of its directors, officers, employees, agents or contractors will be liable to FEVI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which FEVI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FEI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FEI.

4.3 Indemnity by FEI

Subject to Section 4.4, FEI will indemnify, defend and hold harmless FEVI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which FEVI may suffer or incur as a result of any act or omission or error of judgement as a result of which FEI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF FEVI

5.1 Covenants by FEVI

FEVI covenants and agrees to:

(a) fully co-operate with FEI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by FEVI to FEI or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of FEI

FEI hereby represents and warrants to FEVI as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FEI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEI has full power and authority to perform its obligations hereunder,

(b) this Agreement constitutes a valid and binding obligation of FEI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) FEI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of FEVI

FEVI hereby represents and warrants to FEI as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FEVI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEVI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FEVI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2014 and will continue until December 31, 2014, unless terminated earlier pursuant to the provisions hereof. Thereafter the Agreement will automatically be renewed for further one (1) year terms subject to Sections 7.2 and 7.3 below.

7.2 Termination

FEI's appointment hereunder may be terminated at any time:

(a) by FEI giving FEVI written notice of such termination:

(i) if FEVI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if FEVI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against FEVI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of FEVI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or FEVI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event FEVI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by FEVI of written notice thereof from FEI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from FEI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of FEI that FEVI is in breach is conceded to be correct by FEVI or found to be correct by an arbitrator pursuant to Section 8.1;

(b) by FEVI giving FEI written notice of such termination:

(i) if FEI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if FEI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against FEI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of FEI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or FEI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event FEI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by FEI of written notice thereof from FEVI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from FEVI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of FEVI that FEI is in breach is conceded to be correct by FEI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Termination Without Cause

Notwithstanding Section 7.2 above either party may, upon obtaining the other party's written consent, terminate this Agreement without penalty or damages upon giving thirty (30) days written notice.

7.4 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, FEI will have no further obligations under Article 2 and will promptly deliver to FEVI any material documents in the possession of FEI pertaining to the business of FEVI.

7.5 Compensation of FEI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, FEVI will pay to FEI all amounts owing to FEI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this Section, the fees provided for in Article 3 which are payable to FEI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between FEI and FEVI regarding any allegation that FEVI or FEI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the Rules of Procedure for Commercial Mediation of The Canadian Foundation for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

PROTECTION OF PERSONAL INFORMATION

10.1 Collection of Personal Information

FEI and FEVI recognize that during the course of this Agreement each party may provide the other with access to "personal information" and "employee personal information" (jointly "Personal Information") as those terms are defined in the British Columbia Personal Information Protection Act and the Canadian Personal Information Protection and Electronic Documents Act (collectively the "Privacy Laws") as applicable (the "Disclosing Party"), and that disclosure by one party to the other of this Personal Information places an obligation on the receiving party to only collect, use, disclose, retain and secure Personal Information in compliance with the Privacy Laws and FEI's and FEVI's privacy policy, which for reference can be found at www.fortisbc.com (the "Receiving Party").

10.2 Use of Personal Information

The Receiving Party shall only collect, use, disclose or retain Personal Information from the Disclosing Party for the limited purpose for which the Personal Information was disclosed so as to allow the Receiving Party to perform the Services. Any further collection, use, disclosure or retention of Personal Information is strictly prohibited without the Disclosing Party's express consent.

10.3 Representation and Warranty

In addition to the representations given by FEI in Section 6.1 and by FEVI in Section 6.2 herein, FEI and FEVI hereby each represent and warrant that they shall comply with the Privacy Laws and the privacy policy referenced in Section 10.1 above.

PART 11

MISCELLANEOUS

11.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

11.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

11.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

11.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

11.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

11.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement effective on the Effective Date first written above.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

By: ______________________

Title: VP Finance & CFO

FORTISBC ENERGY INC.

By: ______________________

Title: President & CEO

On a shared basis, the personnel from the following departmental units of FEI will provide services to FEVI:

(1) **Corporate.** The role and function of the Corporate department of FEI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs**. The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the FEI companies through the Capital Management Office;

(e) provide high-level policy, strategic and technical advice & expertise to the company's Executive leadership Team regarding regulatory initiatives and issues as well as the regulatory implications of corporate objectives, strategies and business initiatives and projects taking into consideration emerging regulatory developments and market trends;

(f) ensures adequate and appropriate regulatory constructs and mechanisms are put in place and maintained for all separate legal entities under the Gas Utility Segment of FortisBC, taking into consideration the Company's objectives and strategies and market realities;

(g) acts as the Company's focal point of contact with the British Columbia Utilities Commission and ensures the company is fulfilling its obligations regarding governance of Regulatory Orders from the BCUC and Government (Utilities Commission Act);

(h) ensures adequate and appropriate Tariffs and Rates are in place in consideration of the Company's objectives and strategies, market realities, and the approved regulatory constructs and mechanisms;

(i) responsible for the development and execution of corporate regulatory strategy and holds the primary responsibility for the development and maintenance of superior relationships with key interveners, regulatory bodies, market participants and customer representatives;

(j) development of FEI/FEVI financial accounting policies and procedures;

(k) reviewing and maintaining the code of general ledger accounts;

(l) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(m) monthly reporting, variance analysis and year-end forecasting;

(n) external audit coordination and the preparation of non-consolidated financial statements;

(o) annual and multi-year budget processes;

(p) performance measurement and cost analysis;

(q) asset and plant accounting;

(r) the accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner; and

(s) provide administrative support for corporate credit card program.

(3) **Customer Service.** The Customer Service department is responsible for providing the following services:

(a) overall policy direction and oversight of services relating to the Customer Service function;

(b) direction to the Customer Care and Services group and to develop customer education and communication;

(c) market research support including customer satisfaction surveys;

(d) oversee outsourced service provider activities including meter reading and credit and collection; and

(e) manage the Customer Contact centre and billing operations in support of construction orders for service and meter installations, customer billing and answering customer inquiries.

(4) **Human Resources.** This department is focused on providing the following HR services:

(a) ensuring HR direction and programs that affect employees are aligned with departmental and corporate objectives. Areas of responsibility include HR business planning, and compliance with regulatory, and governance reporting;

(b) overseeing the design and delivery of the Total Rewards framework to attract, retain and motivate employees. This includes providing recruiting and selection processes to meet business needs and operational requirements. Other services include compensation, payroll and time administration, benefits administration, pension administration, recruiting, HR Information Systems and master data, and HR metrics, surveys and reporting;

(c) providing direction and delivery of labour relations and advisory services to maintain and foster productive employee/employment relationships. This includes HR advisory services, disability and attendance management and labour relations but not limited to collective agreement interpretation, administration and collective bargaining; and

(d) providing design and delivers employee training and development programs. This includes development and delivery of trades training and in-house apprenticeship programs, learning content management, management training and leadership development, e-learning, competency management and administration and training records.

(5) **Environment, Health and Safety**. This department is focused on providing Environment, Health and Safety services to support governance and related business needs of the operations of the FortisBC Energy group of gas companies. The functional areas and the services provided are:

(a) Environmental Affairs, which manages environmental risks associated with operational activities and the fulfilment of compliance requirements with applicable environmental regulation;

(b) Occupational Health and Safety, which manages employee safety risks as aligned with the maintenance of compliance with WorkSafeBC regulation;

(c) Public Safety, which involves the development of plans and awareness strategies relating to the education of customers, first responders, and the general public around the properties of natural gas, and about steps to be taken in emergent situations;

(d) Emergency Preparedness, which involves the management of emergency management system compliance with all applicable legislation. An annual exercise program supports operational readiness;

(e) Business Continuity Planning involves inter-departmental planning that will result in an effective operational response and the restoration and resumption of core business functions if a business interruption occurs; and

(f) Corporate Security, which manages corporate security risks.

(6) **Energy Supply and Resource Development ("ES&RD").** The functional areas and the services provided are:

(a) overall policy direction and oversight of services relating to the ES&RD functions;

(b) gas supply infrastructure planning and major capacity and sustainment initiatives management function;

(c) identifying and developing new regional projects as well as system infrastructure projects within the Company's current service areas, including pipeline, compressor, and storage projects.

(7) **Information Systems.** This department provides information technology application and infrastructure management services including:

(a) development of short and long term strategy considering business requirements as they relate to evolving technologies. This includes the responsibility of planning, forecasting and design of future infrastructure capacity requirements that will support the Company's objectives.

(b) identifying, designing, operating, and maintaining the availability, security and integrity of technology and critical enterprise infrastructure including hardware and networks;

(c) management of the costs for the Wide Area Network (WAN), including balancing appropriate performance with cost;

(d) overseeing end user technical support for all employees, contractors, applications and associated equipment;

(e) management and monitoring of all telephony contracts, including cellular;

(f) management and costs of all large printing devices for the organization; and

(g) life cycle management of technology assets.

(8) **Facilities**. This department is responsible for operating and maintaining office, shop, warehouse and yard facilities. The services provided include:

(a) building and yard asset operation and maintenance and physical security;

(b) project management for construction, renovation or relocation;

(c) space planning, office furniture and equipment; and

(d) mailroom and reception services.

(9) **Operations Support**. This department is responsible for providing Measurement Services, Supply Chain Services, and Property Services.

(a) Measurement Service includes the management of the measurement device fleet which includes, but is not limited to the inspection, compliance sampling, sealing and repair of meters and measurement devices;

(b) Supply Chain Services include:

i. Mechanical Services for manufacturing and repairing equipment and tools for Operations and fabrication and install services for transmission and distribution projects;

ii. Material Services for managing the flow of field materials, tools and equipment used throughout the Company;

iii. Procurement Services ensures the appropriate processes are followed and agreements are in place when FEI acquires materials and services. Additionally, included are market research, risk management, tender evaluations and vendor management.

(c) Property Services includes support for property taxation, negotiation of land acquisition, leases and disposal as well as related environmental reviews, maintenance of right of way (ROW) agreements and First Nations land negotiations.

(10) **Engineering Services and Project Management**. This is comprised of Asset Management, Geographic Information Systems, Engineering and Project Management Office.

(a) Asset Management services include overseeing the gas system assets, system capacity planning, and system integrity management planning to ensure safe and reliable energy delivery. This includes defining operations and maintenance activities critical to the Integrity Management Plan, operating and maintaining cathodic protection systems, and capital planning.

(b) Geographic Information Systems (GIS) services include completing new mains and service construction drawings and as-built mapping. It is also responsible for developing and maintaining the GIS mapping system, maintaining gas system asset records for distribution and transmission facilities and providing Public Underground Location Services as requested through BC One Call;

(c) Engineering provides engineering design, and drafting services to the Project Management Office, as well as technical guidance to Operations. It also provides technical oversight and management of the Gas Lab which provides gas measurement and analysis services to ensure appropriate levels of odourization in the natural gas that is delivered to customers; and

(d) Project Management Office delivers capital projects related to pipelines and above ground facilities that enhance transmission and distribution assets.

(11) **Operations.** The role and function of the Operations – Distribution department is to provide the following services:

(a) policy direction and oversight of services related to Distribution operations and maintenance, emergency management services, account services and fieldwork, Operations Support;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers;

(c) directors, regional managers and front line field managers who are responsible for day-to-day operations in specific geographic areas; and

(d) order initiation and processing, scheduling, dispatching, performance reporting, claims management and training.

(12) **Energy Solutions & External Relations ("ES&ER").** ES&ER services provided on a shared service basis fall into the following service areas:

(a) responsible for providing overall policy direction and oversight of services relating to the Energy Solutions and External Relations function, including overseeing the development and implementation of new service offerings, initiatives and programs;

(b) provides overall policy direction and oversight of services relating to all markets and customer segments;

(c) develops communications, supports the communications collateral requirements of Builder/Developer and Commercial/Industrial Account Managers, develops and executes events and undertakes trade relations activities that support sales efforts;

(d) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(e) oversees both the Main Extension test, and the Company's service line policies;

(f) evaluates existing offerings to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new and amended services to the British Columbia Utilities Commission;

(g) develops customer energy use and customer additions forecasts;

(h) provides analysis and decision support to internal and external customers on longer-term supply/demand and pricing issues, and performs portfolio modeling; Examples of internal customers would include various departments such as Gas Supply, Finance, Regulatory, System Planning and Operations. Examples of external customers would include various municipalities and other government agencies as well as individual (mainly commercial) customers;

(i) builds and fosters relationships with communities, government, First Nations, and business associations to engage these key stakeholders in FEVI's key projects and initiatives;

(j) provides internal and external communications services for the Company, including, customer, employee and stakeholder communications, media relations and safety education messaging;

(k) provides Energy Efficiency and Conservation ("EEC") services including program development, administration, delivery, monitoring and reporting;

(l) provides Technical Support to external customers, and internal customers including sales and the EEC group;

(m) develops both Regional Resource Plans and Integrated Resource Plans for all companies.

Cost Allocation Drivers

Department	**Allocation Method**
Corporate	# of Customers
Finance & Regulatory Affairs	# of Customers
Customer Service Human Resources	# of Customers # of Customers # of Employees
Environment, Health & Safety	# of Customers
Energy Supply and Resource Development	# of Customers
Information Technology	# of Customers # of Employees
Facilities	# of Customers # of Employees
Operations Support	# of Customers
Engineering Services and Project Management	# of Customers Specific Allocation %
Operations	# of Customers # of Employees Specific Allocation %
Energy Solutions & External Relations	# of Customers

Note 1: Does not include Timesheet (or Direct Charge) allocations.
Note 2: The Shared Service Fee may be amended from time to time by the written agreement of the parties.

Schedule “A”

Description of Services

Schedule "B"

Shared Service Fee

AMENDED AND RESTATED
SHARED SERVICES AGREEMENT

THIS AGREEMENT is made effective January 1, 2014 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (WHISTLER) INC.
(formerly Terasen Gas (Whistler) Inc.)
16705 Fraser Highway,
Surrey, British Columbia
V4N 0E8

("FEW")

AND:

FORTISBC ENERGY INC.
(formerly Terasen Gas Inc.)
16705 Fraser Highway,
Surrey, British Columbia
V4N 0E8

("FEI")

WHEREAS

A. FEW is the owner and operator of propane distribution facilities, which are being converted to natural gas distribution facilities throughout 2009, in British Columbia serving the community of Whistler (the "Facilities"); and

B. FEW wishes to retain FEI to provide certain administrative and management services to it in respect to the ownership and common management of the operation of its transmission pipeline and distribution business and to receive services on an as and when required basis from third party contractors retained by FEI on the terms and conditions set out herein.

WITNESSES that, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1
INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement,

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the administrative and management services to be provided to FEW by FEI and as more particularly described in Section 2.1 and any services provided on an as and when required basis under contract to FEI by a third party contractor which services are used by or provide benefit to FEW.

1.2 Schedules

The following are the schedules attached to, and are incorporated by reference into, this Agreement:

Schedule "A"	Description of Services
Schedule "B"	Shared Service Fee

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,

2) any reference in this Agreement to a designated "Article", "Section" or other subdivision is to the designated Article, Section or other subdivision of this Agreement,

3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, Section or other subdivision,

4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,

5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and

6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

FEI hereby agrees to provide to FEW the Services, including those administrative and management services described in Schedule "A".

2.2 No Obligation to Provide Additional Services

FEI shall not perform, and FEI shall have no obligation to perform, any services on behalf of FEW in respect of the Facilities other than as set out in this Agreement or any similar agreement.

2.3 Consultation with FEW

FEI will consult with FEW as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between FEI and FEW. In performing the Services, FEI shall be an independent contractor. FEI employees shall not be considered employees of FEW for any purpose.

2.5 Compliance

In performing the Services, FEI will comply with all Applicable Laws.

PART 3

COMPENSATION

3.1 Compensation for Services

FEW agrees to pay compensation to FEI for the Services in accordance with this Section 3.1. FEW agrees to pay to FEI the Shared Service Fee as set out in Schedule "B" for the administrative and management services provided by FEI employees and FEW agrees to pay for the Services provided by a third party contractor retained by FEI, such portion of the amount invoiced by the third party contractor as is determined by FEI to be allocable to FEW based on the nature and extent of third party services actually received in the applicable period. .

3.2 Amendment to Costs

The amounts set out in Schedule "B" may be amended from time to time by agreement between the parties to reflect any material change in the cost of providing the Services or in the business operations of FEW.

3.3 Invoicing

FEI will invoice FEW (the "Invoice") in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

(a) Except with respect to those portions of an Invoice which are the subject of a bona fide dispute between the parties, invoices shall be payable within thirty (30) days from the date of the invoice.

(b) Any amount to be remitted by FEW to FEI and not remitted on or before the date on which it is due shall thereafter bear interest at an annual rate equal to the prime rate of interest of the Toronto-Dominion Bank (or its successor or permitted assign) (Toronto, Main Branch) plus one percent (1%) calculated daily from the date the amounts become due.

(c) FEI will prepare financial accounting of the actual costs and the allocated costs, and will make adjustments based on additional amount to be paid by FEW or return an overpayment.

(d) Payments due and owing as a result of the accounting will be paid no later then the end of the first quarter of the following year.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by FEW

Subject to Section 4.4, FEW will indemnify, defend and hold harmless FEI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FEI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FEI.

4.2 Limitation of Liability of FEI

Neither FEI nor any of its directors, officers, employees, agents or contractors will be liable to FEW for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which FEW may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FEI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FEI.

4.3 Indemnity by FEI

Subject to Section 4.4, FEI will indemnify, defend and hold harmless FEW from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which FEW may suffer or incur as a result of any act or omission or error of judgement as a result of which FEI is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF FEW

5.1 Covenants by FEW

FEW covenants and agrees to:

(a) fully co-operate with FEI in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by FEW to FEI or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of FEI

FEI hereby represents and warrants to FEW as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FEI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEI has full power and authority to perform its obligations hereunder,

(b) this Agreement constitutes a valid and binding obligation of FEI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) FEI possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of FEW

FEW hereby represents and warrants to FEI as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder

(a) FEW is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEW has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FEW enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2014 and will continue until December 31, 2014, unless terminated earlier pursuant to the provisions hereof. Thereafter the Agreement will automatically be renewed for further one (1) year terms subject to Sections 7.2 and 7.3 below.

7.2 Termination

FEI's appointment hereunder may be terminated at any time:

(a) by FEI giving FEW written notice of such termination:

(i) if FEW becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if FEW makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against FEW seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of FEW or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or FEW consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event FEW breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by FEW of written notice thereof from FEI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from FEI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of FEI that FEW is in breach is conceded to be correct by FEW or found to be correct by an arbitrator pursuant to Section 8.1;

(b) by FEW giving FEI written notice of such termination:

(i) if FEI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if FEI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against FEI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of FEI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or FEI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; and

(ii) in the event FEI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by FEI of written notice thereof from FEW or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from FEW and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of FEW that FEI is in breach is conceded to be correct by FEI or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Termination Without Cause

Notwithstanding Section 7.2 above either party may, upon obtaining the other party's written consent, terminate this Agreement without penalty or damages upon giving thirty (30) days written notice.

7.4 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, FEI will have no further obligations under Article 2 and will promptly deliver to FEW any material documents in the possession of FEI pertaining to the business of FEW.

7.5 Compensation of FEI on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, FEW will pay to FEI all amounts owing to FEI hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this Section, the fees provided for in Article 3 which are payable to FEI on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between FEI and FEW regarding any allegation that FEW or FEI is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the Rules of Procedure for Commercial Mediation of The Canadian Foundation for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

PROTECTION OF PERSONAL INFORMATION

10.1 Collection of Personal Information

FEI and FEW recognize that during the course of this Agreement each party may provide the other with access to "personal information" and "employee personal information" (jointly "Personal Information") as those terms are defined in the British Columbia Personal Information Protection Act and the Canadian Personal Information Protection and Electronic Documents Act (collectively the "Privacy Laws") as applicable (the "Disclosing Party"), and that disclosure by one party to the other of this Personal Information places an obligation on the receiving party to only collect, use, disclose, retain and secure Personal Information in compliance with the Privacy Laws and FEI's and FEW's privacy policy, which for reference can be found at www.fortisbc.com (the "Receiving Party").

10.2 Use of Personal Information

The Receiving Party shall only collect, use, disclose or retain Personal Information from the Disclosing Party for the limited purpose for which the Personal Information was disclosed so as to allow the Receiving Party to perform the Services. Any further collection, use, disclosure or retention of Personal Information is strictly prohibited without the Disclosing Party's express consent.

10.3 Representation and Warranty

In addition to the representations given by FEI in Section 6.1 and by FEW in Section 6.2 herein, FEI and FEW hereby each represent and warrant that they shall comply with the Privacy Laws and the privacy policy referenced in Section 10.1 above.

PART 11

MISCELLANEOUS

11.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

11.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

11.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

11.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

11.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

11.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement effective on the Effective Date first written above.

FORTISBC ENERGY (WHISTLER) INC.

By: ML

Title: VP Finance & CFO

FORTISBC ENERGY INC.

By:

Title: President & CEO

On a shared basis, the personnel from the following departmental units of FEI will provide services to FEW:

(1) **Corporate.** The role and function of the Corporate department of FEI is to provide:

(a) governance and liaisons to direct development and implementation of strategic, operational and capital plans;

(b) governance assurance that controls are in place to ensure the Company's are safeguarded and optimized in the best interests of shareholders, customers and other stakeholders;

(c) alignment and communication of the vision and direction to employees and other stakeholders;

(d) executive level succession planning and development to prepare and maintain exceptional leadership; and

(e) act as the principal spokesperson in maintaining close communication with government and the public.

(2) **Finance and Regulatory Affairs**. The role and function of the Finance and Regulatory Affairs department is to provide the following services:

(a) policy direction and oversight of services related to key financial areas including Strategic Planning, Regulatory Affairs, management and financial reporting, and the capital management office;

(b) oversee the understanding, communication and adherence to accounting policies procedures and practices;

(c) lead financial elements of regulatory processes;

(d) establish and execute the process for managing and facilitating the prioritization of all capital expenditures in the FEI companies through the Capital Management Office;

(e) provide high-level policy, strategic and technical advice & expertise to the company's Executive leadership Team regarding regulatory initiatives and issues as well as the regulatory implications of corporate objectives, strategies and business initiatives and projects taking into consideration emerging regulatory developments and market trends;

(f) ensures adequate and appropriate regulatory constructs and mechanisms are put in place and maintained for all separate legal entities under the Gas Utility Segment of FortisBC, taking into consideration the Company's objectives and strategies and market realities;

(g) acts as the Company's focal point of contact with the British Columbia Utilities Commission and ensures the company is fulfilling its obligations regarding governance of Regulatory Orders from the BCUC and Government (Utilities Commission Act);

(h) ensures adequate and appropriate Tariffs and Rates are in place in consideration of the Company's objectives and strategies, market realities, and the approved regulatory constructs and mechanisms;

(i) responsible for the development and execution of corporate regulatory strategy and holds the primary responsibility for the development and maintenance of superior relationships with key interveners, regulatory bodies, market participants and customer representatives;

(j) development of FEI/FEW financial accounting policies and procedures;

(k) reviewing and maintaining the code of general ledger accounts;

(l) accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

(m) monthly reporting, variance analysis and year-end forecasting;

(n) external audit coordination and the preparation of non-consolidated financial statements;

(o) annual and multi-year budget processes;

(p) performance measurement and cost analysis;

(q) asset and plant accounting;

(r) the accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner; and

(s) provide administrative support for corporate credit card program.

(3) **Customer Service**. The Customer Service department is responsible for providing the following services:

(a) overall policy direction and oversight of services relating to the Customer Service function;

(b) direction to the Customer Care and Services group and to develop customer education and communication;

(c) market research support including customer satisfaction surveys;

(d) oversee outsourced service provider activities including meter reading and credit and collection; and

(e) manage the Customer Contact centre and billing operations in support of construction orders for service and meter installations, customer billing and answering customer inquiries.

(4) **Human Resources.** This department is focused on providing the following HR services:

(a) ensuring HR direction and programs that affect employees are aligned with departmental and corporate objectives. Areas of responsibility include HR business planning, and compliance with regulatory, and governance reporting;

(b) overseeing the design and delivery of the Total Rewards framework to attract, retain and motivate employees. This includes providing recruiting and selection processes to meet business needs and operational requirements. Other services include compensation, payroll and time administration, benefits administration, pension administration, recruiting, HR Information Systems and master data, and HR metrics, surveys and reporting;

(c) providing direction and delivery of labour relations and advisory services to maintain and foster productive employee/employment relationships. This includes HR advisory services, disability and attendance management and labour relations but not limited to collective agreement interpretation, administration and collective bargaining; and

(d) providing design and delivers employee training and development programs. This includes development and delivery of trades training and in-house apprenticeship programs, learning content management, management training and leadership development, e-learning, competency management and administration and training records.

(5) **Environment, Health and Safety**. This department is focused on providing Environment, Health and Safety services to support governance and related business needs of the operations of the FortisBC Energy group of gas companies. The functional areas and the services provided are:

(a) Environmental Affairs, which manages environmental risks associated with operational activities and the fulfilment of compliance requirements with applicable environmental regulation;

(b) Occupational Health and Safety, which manages employee safety risks as aligned with the maintenance of compliance with WorkSafeBC regulation;

(c) Public Safety, which involves the development of plans and awareness strategies relating to the education of customers, first responders, and the general public around the properties of natural gas, and about steps to be taken in emergent situations;

(d) Emergency Preparedness, which involves the management of emergency management system compliance with all applicable legislation. An annual exercise program supports operational readiness;

(e) Business Continuity Planning involves inter-departmental planning that will result in an effective operational response and the restoration and resumption of core business functions if a business interruption occurs; and

(f) Corporate Security, which manages corporate security risks.

(6) **Energy Supply and Resource Development ("ES&RD")**. The functional areas and the services provided are:

(a) overall policy direction and oversight of services relating to the ES&RD functions;

(b) gas supply infrastructure planning and major capacity and sustainment initiatives management function;

(c) identifying and developing new regional projects as well as system infrastructure projects within the Company's current service areas, including pipeline, compressor, and storage projects.

(7) **Information Systems**. This department provides information technology application and infrastructure management services including:

(a) development of short and long term strategy considering business requirements as they relate to evolving technologies. This includes the responsibility of planning, forecasting and design of future infrastructure capacity requirements that will support the Company's objectives.

(b) identifying, designing, operating, and maintaining the availability, security and integrity of technology and critical enterprise infrastructure including hardware and networks;

(c) management of the costs for the Wide Area Network (WAN), including balancing appropriate performance with cost;

(d) overseeing end user technical support for all employees, contractors, applications and associated equipment;

(e) management and monitoring of all telephony contracts, including cellular;

(f) management and costs of all large printing devices for the organization; and

(g) life cycle management of technology assets.

(8) **Facilities**. This department is responsible for operating and maintaining office, shop, warehouse and yard facilities. The services provided include:

(a) building and yard asset operation and maintenance and physical security;

(b) project management for construction, renovation or relocation;

(c) space planning, office furniture and equipment; and

(d) mailroom and reception services.

(9) **Operations Support**. This department is responsible for providing Measurement Services, Supply Chain Services, and Property Services.

(a) Measurement Service includes the management of the measurement device fleet which includes, but is not limited to the inspection, compliance sampling, sealing and repair of meters and measurement devices;

(b) Supply Chain Services include:

i. Mechanical Services for manufacturing and repairing equipment and tools for Operations and fabrication and install services for transmission and distribution projects;

ii. Material Services for managing the flow of field materials, tools and equipment used throughout the Company;

iii. Procurement Services ensures the appropriate processes are followed and agreements are in place when FEI acquires materials and services. Additionally, included are market research, risk management, tender evaluations and vendor management.

(c) Property Services includes support for property taxation, negotiation of land acquisition, leases and disposal as well as related environmental reviews, maintenance of right of way (ROW) agreements and First Nations land negotiations.

(10) **Engineering Services and Project Management**. This is comprised of Asset Management, Geographic Information Systems, Engineering and Project Management Office.

(a) Asset Management services include overseeing the gas system assets, system capacity planning, and system integrity management planning to ensure safe and reliable energy delivery. This includes defining operations and maintenance activities critical to the Integrity Management Plan, operating and maintaining cathodic protection systems, and capital planning.

(b) Geographic Information Systems (GIS) services include completing new mains and service construction drawings and as-built mapping. It is also responsible for developing and maintaining the GIS mapping system, maintaining gas system asset records for distribution and transmission facilities and providing Public Underground Location Services as requested through BC One Call;

(c) Engineering provides engineering design, and drafting services to the Project Management Office, as well as technical guidance to Operations. It also provides technical oversight and management of the Gas Lab which provides gas measurement and analysis services to ensure appropriate levels of odourization in the natural gas that is delivered to customers; and

(d) Project Management Office delivers capital projects related to pipelines and above ground facilities that enhance transmission and distribution assets.

(11) **Operations.** The role and function of the Operations – Distribution department is to provide the following services:

(a) policy direction and oversight of services related to Distribution operations and maintenance, emergency management services, account services and fieldwork, Operations Support;

(b) general management and oversight of services are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers;

(c) directors, regional managers and front line field managers who are responsible for day-to-day operations in specific geographic areas; and

(d) order initiation and processing, scheduling, dispatching, performance reporting, claims management and training.

(12) **Energy Solutions & External Relations ("ES&ER").** ES&ER services provided on a shared service basis fall into the following service areas:

(a) responsible for providing overall policy direction and oversight of services relating to the Energy Solutions and External Relations function, including overseeing the development and implementation of new service offerings, initiatives and programs;

(b) provides overall policy direction and oversight of services relating to all markets and customer segments;

(c) develops communications, supports the communications collateral requirements of Builder/Developer and Commercial/Industrial Account Managers, develops and executes events and undertakes trade relations activities that support sales efforts;

(d) creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues, customer connection policies and regulatory changes (e.g., gas cost increase, rate design changes);

(e) oversees both the Main Extension test, and the Company's service line policies;

(f) evaluates existing offerings to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new and amended services to the British Columbia Utilities Commission;

(g) develops customer energy use and customer additions forecasts;

(h) provides analysis and decision support to internal and external customers on longer-term supply/demand and pricing issues, and performs portfolio modeling; Examples of internal customers would include various departments such as Gas Supply, Finance, Regulatory, System Planning and Operations. Examples of external customers would include various municipalities and other government agencies as well as individual (mainly commercial) customers;

(i) builds and fosters relationships with communities, government, First Nations, and business associations to engage these key stakeholders in FEW's key projects and initiatives;

(j) provides internal and external communications services for the Company, including, customer, employee and stakeholder communications, media relations and safety education messaging;

(k) provides Energy Efficiency and Conservation ("EEC") services including program development, administration, delivery, monitoring and reporting;

(l) provides Technical Support to external customers, and internal customers including sales and the EEC group;

(m) develops both Regional Resource Plans and Integrated Resource Plans for all companies.

Cost Allocation Drivers

Department	Allocation Method
Corporate	# of Customers
Finance & Regulatory Affairs	# of Customers
Customer Service Human Resources	# of Customers # of Customers # of Employees
Environment, Health & Safety	# of Customers
Energy Supply and Resource Development	# of Customers
Information Technology	# of Customers # of Employees
Facilities	# of Customers # of Employees
Operations Support	# of Customers
Engineering Services and Project Management	# of Customers Specific Allocation %
Operations	# of Customers # of Employees Specific Allocation %
Energy Solutions & External Relations	# of Customers Specific Allocation %

Note 1: Does not include Timesheet (or Direct Charge) allocations.
Note 2: The Shared Service Fee may be amended from time to time by the written agreement of the parties.

Schedule “A”

Description of Services

Schedule "B"

Shared Service Fee

AMENDED AND RESTATED
MUTUAL SHARED SERVICES AGREEMENT

THIS AGREEMENT is made effective the 1st day of January, 2014.

BETWEEN:

FORTISBC ENERGY INC., a corporation formed under the laws of British Columbia having an office at 1000-1111 West Georgia Street, Vancouver, British Columbia, V6E 4M3

(hereinafter "FEI")

AND:

FORTISBC INC., a corporation formed under the laws of British Columbia, having an office at Suite 100, 1975 Springfield Road, Kelowna, British Columbia, V1Y 7V7

(hereinafter "FBC")

WHEREAS

A. FEI and FBC are both wholly owned subsidiaries of Fortis Inc.

B. FEI and FBC each require certain services on an as required basis.

C. FEI and FBC are each willing to provide the Services to the other on the terms and conditions contained in this Agreement.

WITNESSETH THAT, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the performance of the Services hereunder;

(b) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international,

judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(c) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(d) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(e) "**Services**" means the professional and management services to be provided by FEI or by FBC respectively, as required by the each of the parties from time to time and any services provided on an as and when required basis under contract to FEI or FBC by a third party contractor which services are used by or provide benefit to the other party.

1.2 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,
2) any reference in this Agreement to a designated "Article", "section" or other subdivision is to the designated Article, section or other subdivision of this Agreement,
3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision,
4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,
5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and
6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Canadian utility industry, shall have such accepted meaning.

1.3 Governing Law

Subject to Section 7.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2

SERVICES

2.1 Services

Each party hereby agrees to provide to the other the Services on an as required basis and to the extent the party providing the Services has the capacity, as determined by it in its sole discretion, to provide such Services.

2.2 No Obligation to Provide Additional Services

Neither party shall perform, and shall have no obligation to perform, any services to the other except as set out in this Agreement or any similar agreement.

2.3 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between FEI and FBC. In performing the Services, each party shall be an independent contractor. FEI employees and FBC employees shall not be considered employees of the other party for any purpose.

2.4 Compliance

In performing the Services, each party will comply with all Applicable Laws and its own applicable standards and policies.

2.5 Confidentiality

The party providing the Services will comply with confidentiality or non-disclosure agreements between the party receiving the Services and any other Person with respect to information required for the Services. Each party waives any right of confidentiality as between the two parties with respect to any information provided by such party to the other party's employees in the course of providing Services.

2.6 Protection of Personal Information

1) FEI and FBC recognize that during the course of this Agreement each party may provide the other with access to "personal information" and "employee personal information" (jointly "Personal Information") as those terms are defined in the British Columbia Personal Information Protection Act and the Canadian Personal Information Protection and Electronic Documents Act (collectively the "Privacy Laws") as applicable (the "Disclosing Party"), and that disclosure by one party to the other of this Personal Information places an obligation on the receiving party to only collect, use, disclose, retain and secure Personal Information in compliance with the Privacy Laws and FEI's and FBC's privacy policy, which for reference can be found at www.fortisbc.com (the "Receiving Party").

2) The Receiving Party shall only collect, use, disclose or retain Personal Information from the Disclosing Party for the limited purpose for which the Personal Information was disclosed so as to allow the Receiving Party to perform the Services. Any further collection, use, disclosure or retention of Personal Information is strictly prohibited without the Disclosing Party's express consent.

3) In addition to the representations given by FEI in Section 5.1 and by FBC in Section 5.2 herein, FEI and FBC hereby each represent and warrant that they shall comply with the Privacy Laws and the privacy policy referenced in Section 2.6(1) above.

PART 3

COMPENSATION

3.1 Compensation for Services and Shared Costs

The party receiving Services agrees to reimburse the party providing Services for all reasonable expenses it has incurred in providing such Services, including, without limitation, such portion of the annual salary and benefits of relevant employees as is determined by the party providing Services to be allocable to the party receiving Services based on the nature and extent of Services actually provided during the applicable period and for Services provided by a third party contractor, such portion of the amount invoiced by the third party contractor as is determined by the party contracting for the Services to be allocable to the party receiving a portion of the Services based on the nature and extent of Services actually received in the applicable period.

3.2 Invoicing

The party providing Services will invoice the other in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.3 Payment

(a) Except with respect to those portions of an invoice which are the subject of a bona fide dispute between the parties, the party receiving Services shall within thirty (30) days after receipt of an invoice from the party providing Services, pay the amount specified in such invoice.

(b) Any amount to be remitted by the party receiving Services and not remitted on or before the date on which it is due shall thereafter bear interest at rate of 1.5% per month (18% per annum).

3.4 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this

Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by FBC

Subject to Section 4.4 , FBC will indemnify, defend and hold harmless FEI and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FEI's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FEI.

4.2 Indemnity by FEI

Subject to Section 4.4, FEI will indemnify, defend and hold harmless FBC and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with FBC's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of FBC.

4.3 Limitation of Liability of party providing Services

Neither the party providing Services nor any of its directors, officers, employees, agents or contractors will be liable to the other for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which the party receiving Services may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with the provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of the party providing Services.

4.4 Consequential Losses

Each party acknowledges and agrees that notwithstanding anything else in this Agreement, in no event shall a party or any of their officers, directors, employees, shareholders, agents, or representatives be liable to the other party, any of its affiliates, or any other party for any special, indirect, incidental, exemplary, or consequential damages or loss of goodwill whether such liability is based on contract, tort, negligence, strict liability, or otherwise, in any way arising from or relating to this Agreement or the performance or non-performance of the Services, even if the party has been notified of the possibility or likelihood of such damages occurring.

PART 5

REPRESENTATIONS AND WARRANTIES

5.1 Representations and Warranties of FEI

FEI hereby represents and warrants to FBC as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FEI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FEI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FEI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

5.2 Representations and Warranties of FBC

FBC hereby represents and warrants to FEI as representations and warranties which are true as at the date hereof and which will be true during the term of FEI's appointment hereunder:

(a) FBC is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and FBC has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of FBC enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 6

DURATION, TERMINATION AND DEFAULT

6.1 Effective Date and Term

This Agreement will be effective from January 1, 2014 and will end on December 31, 2014, unless earlier terminated pursuant to the provisions hereof. Thereafter this Agreement will automatically be renewed for further one (1) year terms from January 1 to December 31, subject to Section 6.2 below.

6.2 Termination

This Agreement may be terminated by either FEI or FBC in their sole and absolute discretion at any time by giving fourteen (14) days notice after receipt by either FEI or FBC of written notice thereof from the other party. Such termination shall not affect any rights of the parties which have accrued prior to the date of termination and shall not relieve any party from its obligations which have arisen during the term of this Agreement.

6.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, each party will have no further obligations under Part 2 and will promptly deliver to the other any material documents in the possession of each pertaining to the business of the other.

6.4 Compensation of party providing Services on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, each party will pay to the other all amounts owing hereunder (including any amount owing on account of the fees provided for in Part 3 calculated up to the date of expiry or termination); provided that for the purposes of this section, the fees provided for in Part 3 which are payable to the party providing Services on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 7

ARBITRATION

7.1 Arbitration

Any dispute between FEI and FBC regarding any allegation that FEI or FBC is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 7.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the rules of National Arbitration Rules of the ADR Institute of Canada Inc. from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 7.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 8

MISCELLANEOUS

8.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party for whom it is intended at the address of such party shown on the first page of this Agreement. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

8.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

8.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

8.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

8.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

8.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

[Execution page follows]

IN WITNESS WHEREOF, the parties hereto have executed this Agreement effective as of the day and year before written.

FORTISBC ENERGY INC.

By: ______________________

Name: Michele Leeners

Title: VP Finance & CFO

FORTISBC INC.

By: ______________________

Name: John Walker

Title: President & CEO

Appendix F2

CORPORATE SERVICES STUDY AND AGREEMENTS

KPMG

Fortis Inc. and FortisBC Holdings Inc.

Corporate Services Cost Allocation Model

June 10, 2013

Table of Contents

1. Executive Summary

FortisBC Energy Inc. (FEI) retained KPMG to perform an independent review of Fortis Inc.'s (FI) (see Section 3 for an explanation of the organizational structure) corporate services cost allocation methodology and the reasonability of the costs of the corporate services provided by FI to FortisBC Holdings Inc (FHI).

KPMG were also retained to review the corporate services cost allocation methodology and the reasonability of the costs of the corporate services provided by FHI to FortisBC Energy Utilities (FEU) (defined as FEI, FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW)) and FortisBC Alternate Energy Services Inc. (FAES) and several other inactive companies ("other subsidiaries").

The basis of the review is to assist FEI in preparation of their 2014-2018 Performance Based Ratemaking Application (Application) to the British Columbia Utilities Commission ("BCUC" or "the Commission").

KPMG has previously issued a report dated June 22, 2009, on the corporate services cost allocation model used by FHI (formerly Terasen Gas Inc.) as part of the 2010/11 Revenue Requirements Application.

Specifically, KPMG was engaged to assess:

- Whether the corporate services department cost (or "cost pool") met Management's assessment criteria for share cost pools in Section 4.1 of this report and therefore deemed relevant and appropriate for allocations; and
- Whether the utilized cost allocators ("allocators" or "drivers") related to the corporate services cost pools met Management's assessment criteria for cost allocators in Section 4.2 of this report and therefore deemed to be reasonable to use as a basis for allocation.

Evaluation of FI and FHI Corporate Services Cost Allocation Model

KPMG assessed the reasonability of the allocation methodology and the costs allocated from FI to FHI and FHI to FEU, respectively, against the evaluation criteria in Section 4 of this report. In completing the examination of the shared services cost allocation methodology and resulting costs, KPMG found the following:

Shared Cost Pools

KPMG reviewed the completeness of the identified corporate services cost pools through the procedures noted in Section 7, which included:

- Discussed and reviewed general ledger costs which were not allocated to FI's and FHI's corporate services cost pools with managers to assess if related costs were incurred for the benefit of FHI and FEU, respectively, and therefore should be allocated to a corporate services cost pool of FI and FHI;
- Reviewed corporate services cost pools, which included both labour and/or non-labour components, through discussions with Management and divisional personnel of the activities undertaken to see if other general ledger costs were associated with these existing corporate services cost pool amounts and should be included in these corporate services cost pools; and

- Reviewed and discussed with Management and divisional personnel assigned to corporate services cost pools to ascertain if other individuals are associated with services benefiting FHI and FEU and should therefore also be included.

KPMG assessed the accuracy of the corporate services cost pools through the procedures noted in Section 7, which included:

- For a sample of individuals in each corporate services cost pool, agreed their roles to job descriptions, employee organizational charts and/or questionnaires;
- Reconciled corporate services cost pool details to the 2013 budget figures from its Revenue Requirement Application;
- KPMG discussed organizational changes with Management that may change corporate services cost pools and assessed if changes to corporate services cost pools, if any, were supported; and
- KPMG assessed the final corporate services cost pools against corporate services cost pool principles discussed in Section 4.1 of this report.

KPMG finds the corporate services cost pools for both FI and FHI to be reasonable and notes comments detailed in Section 7 of this report.

Cost Allocators and Application

KPMG assessed the proposed cost pool allocators and their application by performing the procedures noted in Section 7, which included:

- Compared the cost proposed allocators to prior year cost allocators and discussed any changes, if any, with Management;
- Compared proposed cost allocators to each of the established cost allocator assessment principles discussed in Section 4 of this report and to other possible allocator(s) alternatives;
- Assessed other possible cost allocator alternatives; and
- Re-performed allocations using the proposed cost allocators and discussed the resulting allocation with Management to ensure the resulting FHI and FEU allocation is reasonable in nature and amount, as they meet the internal objectives and principles criteria established in Section 4 of this report.

KPMG finds the corporate cost allocators for both FI and FHI to be reasonable and notes comments detailed in Section 7 of this report.

KPMG Conclusion

Based on the scope and the results of the above procedures and other procedures more fully described in Section 7, KPMG is of the view that the corporate services cost pools and the cost allocators proposed for use in the FI and FHI corporate services cost allocation models both meet the internally generated objectives and evaluation criteria established by FI and FHI as detailed in Section 4 of this report, and as a result form a reasonable and objective basis of allocation.

2. Purpose of Report

2.1 Project Scope

KPMG was retained by FEI to conduct an evaluation of FI's and FHI's 2013 corporate services cost allocation model in preparation for FEI's Application.

Specifically, KPMG was engaged to assess:

- Whether the corporate services cost pools met Management's assessment criteria for the corporate services cost pools in Section 4.1 of this report and were therefore deemed relevant and appropriate for allocations; and
- Whether the utilized cost allocators related to the corporate services cost pools met Management's assessment criteria for cost allocators described in Section 4.2 of this report and were therefore deemed to be appropriate to use as a basis for allocation.

KPMG completed procedures over the 2013 cost allocation model using the 2013 budget.

2.2 Scope Limitations

This section provided details of the limitations of this Study. These are as follows:

Management responsibility:

FI and FEU's corporate services costs allocation model report is the responsibility of management who also maintain responsibility for the accuracy and completeness of the data and information associated with the corporate services costs allocation methodology and associated costs.

KPMG engagement:

Our engagement is to assess and comment on the corporate services cost allocation methodology based upon the results of procedures outlined in Section 7 of this report.

This evaluation does not constitute an audit of the corporate cost allocation methodology, including associated cost pools and cost allocators. Accordingly, we do not express such an opinion on such matters. For avoidance of doubt, KPMG has performed specified procedures only and neither audited nor reviewed the underlying corporate services cost pools, or the data that underpins the FI and FHI cost allocators that form the basis of the cost allocations of FI and FHI.

FI and FHI prepared the proposed corporate services cost allocations using 2013 budget O&M figures from FEU's 2012-2013 RRA. Our findings and conclusions are therefore limited accordingly and do not assess the reasonableness of such amounts.

The information contained herein is for the internal use of FortisBC Management, the Audit and Risk Committee, and Board of Directors. It is understood that this report will be distributed by the FEU externally to the BC Utilities Commission as part of the regulatory process and by other Fortis subsidiaries to their regulators. Contrary to the provisions of this paragraph, KPMG disclaim any responsibility or liability for losses, damages, or costs incurred by anyone as a result of any external circulation, publication, reproduction, or use of the information contained herein.

2.3 Report Structure

This report is structure as follows:

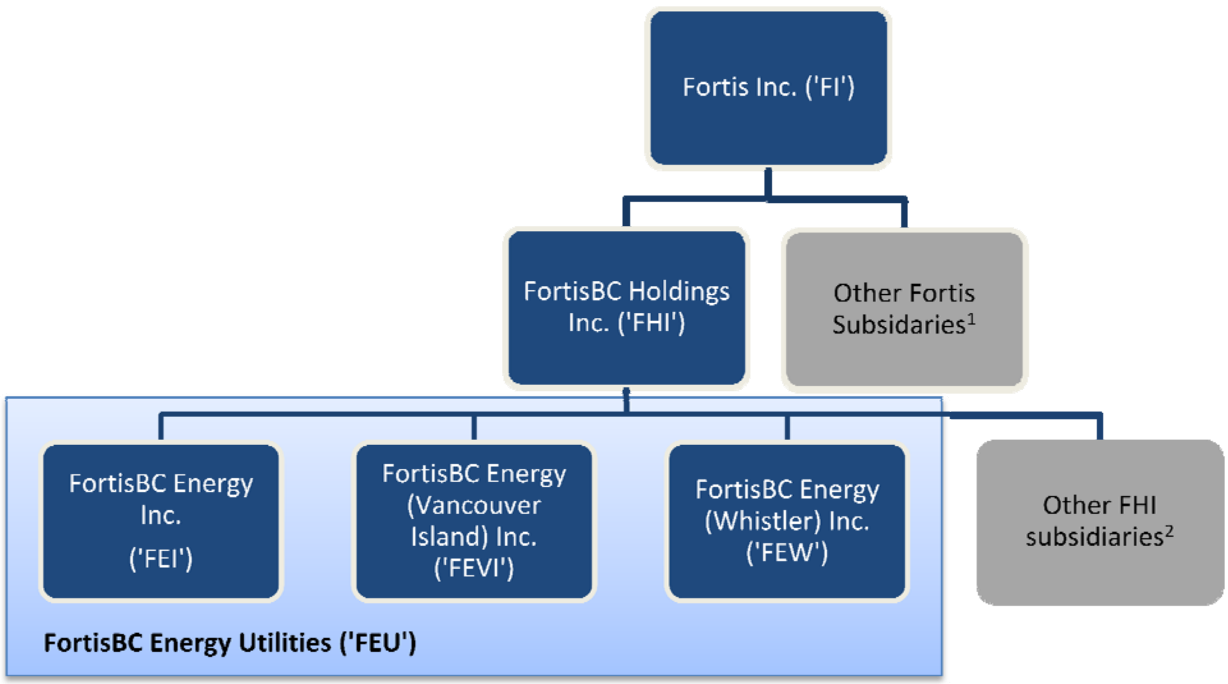
- **Section 1: Executive Summary** - Includes a brief discussion of KPMG's review approach and summary of findings.
- **Section 2: Purpose of Report** - Outlines the structure of the report and provides a brief explanation of each section.
- **Section 3: Background** - Provides background on the structure of the FI and FHI.
- **Section 4: Corporate Services Allocation Principles** – Provides based assessment criteria that has been internally generated by FortisBC Management to evaluate both costs analyzed and methodologies used.
- **Section 5: Management's Corporate Cost Allocation Model – Fortis Inc** - Provides details of the calculation made in relation to the corporate services cost pools of FI, the cost allocator(s) applied and the resultant allocation of share service costs from FI to FHI.
- **Section 6: Management's Corporate Cost Allocation Model – FortisBC Holdings Inc** - Provides details of the calculation made in relation to the corporate services cost pools of FI, the cost allocator(s) applied and the resultant allocation of share service costs from FI to FHI.
- **Section 7: KPMG Findings** - Provides KPMG's findings from the specified procedures it performed to assess the corporate services cost allocation methodology.

3. Background

FI is traded on the TSX and is principally an international utility holding company. Its business operations are different than those of its operating subsidiaries and are primarily focused on providing a market return to its widely held shareholder base, as well as providing strategic direction, leadership, risk management and oversight and equity to its subsidiaries including FHI.

While FI owns FHI and its subsidiaries, FHI has management responsibility for its subsidiaries. The following organization chart illustrates FHI's relationships to regulated and affiliate companies.

Figure 3.1 – Organization Chart



[1] "Other Fortis Subsidiaries" include: Belize Electricity, Belize Electric Company Limited, Fortis Turks and Caicos, FortisAlberta Inc., FortisBC Inc., Newfoundland Power Inc., Maritime Electric Inc., FortisOntario Inc. (regulated and non-regulated) and Fortis Properties Inc.

[2] Other FHI subsidiaries include interests held in FAES, Customer Works LP and 630319 B.C. Ltd. These entities have been aggregated in the allocation model due to their allocation otherwise determined being less than 1% of the total corporate services cost pool due to their limited size and/or limited operations.

FHI is primarily a utility holding company which provides oversight functions to FEU as well as its other regulated and non-regulated affiliates.

FEU operates under a corporate management structure, where leadership for FEU resides primarily in FEI, with additional leadership from FHI, which provides governance and oversight to all entities in FEU.

FHI is owned directly by FI. FHI is the parent company of FEI, FEVI and FEW. FHI provides a number of administrative, accounting and other reporting services to its subsidiaries. FHI utilizes a cost allocation model to attribute its corporate services operating costs to FEU, and other FHI subsidiaries.

FEU provide natural gas transmission and distribution services to their customers and obtain natural gas commodity on behalf of its customers. Pursuant to the Utilities Commission Act (British Columbia), the

BCUC regulates such matters as tariffs, rates, construction, operations, financing and accounting for FEU.

It is common in the utility industry to have a parent company provide services to subsidiaries for a number of reasons such as sharing overhead costs, sharing of specific expertise, and obtaining economies of scale. In this case, FI and FHI have different and complementary responsibilities of providing access to capital and strategic oversight to FEU.

4. Corporate Services Cost Allocation Principles

4.1 Management's Assessment Criteria for Corporate Services Cost Pools

Management applies the following basic assessment criteria when evaluating which shared goods or service expenditures of FI and FHI should be included in their respective cost pools to be allocated to FHI and FEU, respectively, in their cost allocation models. Management has also represented that this same criteria was applied in determining their historic corporate services cost pools.

The goods or services must have one or some of the following basic attributes to be included in a corporate services cost pool to be allocated:

- The goods acquired by or services performed at FI or FHI provide a direct or indirect benefit to FHI and FEU, respectively, or their respective customer base.
- If the goods are no longer acquired or the services are no longer provided from FI or FHI, then FHI and FEU, respectively, would be negatively impacted and would have to find another source for such good or service or perform such service on its own.
- The good or service would be provided by FHI and FEU, respectively, if it was a standalone operation performing its own service, compliance and reporting functions.

4.2 Management's Assessment Criteria for Cost Allocators

Management developed guiding principles for the capital cost allocation methodology and applied the following commonly used cost driver assessment principles when evaluating which cost driver should be used to allocate a cost.

	Internal FI and FHI Criteria	Detail
1	**Cost Causality**	The identified driver, being it work effort or investment, has a direct correlation to the cost of the services or goods and also has a direct effect on the level of service.
2	**Objective Results**	The use of the allocation driver results in an objective allocation amount that is free from undue bias.
3	**Cost Effectiveness**	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
4	**Stability Over Time**	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.
5	**Transparent and Supportable Methodology**	The driver used and the source or basis on how it is determined is visible to all parties affected.The allocation approach is supported by a defined and documented methodology, model and other supporting documentation.
6	**Regulatory Precedence**	The cost allocation methodology has been tested and approved through previous regulatory reviews.
7	**Distinguishable from Directly Allocated Costs**	The costs must be distinguished from those that are directly charged to the entity.
8	**Accuracy of Underlying Data**	Any data used in the methodology should be accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output.
9	**Flexibility/Adaptability**	The methodology should be able to accommodate future changes in regulations, accounting and organization changes with reasonable ease.

5. Management's Corporate Cost Allocation Model – Fortis Inc

5.1 FI Cost Allocation Model

Costs for corporate services are calculated at the cost centre level (e.g. Executive, Treasury) and combined into a cost pool for allocation. This cost pool is then allocated to FI's subsidiaries, including FHI, using the relative total asset base of each subsidiary.

The graphic below summarizes the steps taken by FI to calculate the portion of its recoverable operating costs to allocate to FHI. The sections below describe the components in the model.

Figure 5.1 – FI Cost Allocation Model

FI Operating Costs (see 5.2)	-	Specified Exclusions (see 5.3)	-	Fortis Properties Management Fees (see 5.4)	=	FI Recoverable Operating Costs (see 5.5)	X	FHI Proportion of Total Assets (see 5.6)	=	FHI Portion of FI Recoverable Operating Costs

5.2 FI Operating Costs

FI's activities are broad and focused on strategic direction, leadership, risk management and oversight of subsidiary companies. In addition, FI provides management services to FHI that enables FHI to take advantage of the benefits that arise through economies of scale by providing access to capital markets as a shared corporate service and to meet regulatory requirements as an issuer of equity in Canada.

All business services as listed in the cost allocation model are commonly found in gas utilities.

Table 5.2 outlines the primary activities provided by FI (note this is not an exhaustive list).

Table 5.2 – FI Management Services Description

Function	Activities Include
Executive	• Provide strategic direction, 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	• Performs Fortis Inc. treasury services and provides oversight to subsidiary companies for debt and equity financings, maintaining the capital structure, corporate cash management and forecasting, management of hedging activities, 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 review of compliance with US GAAP, 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 Enterprise Risk Management program approach.
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.

5.3 Specified Exclusions

FI incurs costs primarily in support of the utilities; however some operating costs are not eligible for inclusion in customer rates and are not passed on to the regulated utilities in the form of a management fee. The costs excluded from the calculation of the FI Management fee include:

- Debt financing costs (i.e. interest on debt and dividends associated with preference equity);
- All identifiable business development costs related to potential and completed acquisitions. This includes 50% of all compensation related to the President & CEO, VP Finance & CFO, and Manager Treasury.

In order to calculate the portion of FI labour costs associated with shareholder-related (business development) activities, and therefore, to be excluded from the recoverable regulated operating costs, management estimates the approximate time spent by the three senior executives (President & CEO, VP Finance & CFO, and Manager Treasury) on shareholder related activity. Consistent with the prior year, Management estimates that 50% of the role of these executives is estimated to be supporting business development activities; therefore 50% of the labour and associated benefit costs with them have been excluded from the operating costs charged to FHI.

5.4 Fortis Properties Management Fee

FI charges an annual management fee to Fortis Properties Inc. (FP), a non-regulated subsidiary of FI for the corporate services provided by FI. The management fee received from FP is used to partially offset FI's operating costs and reduces the amount to be allocated to the regulated utilities.

5.5 FI Recoverable Operating Costs

Operating costs allocated from FI to FHI include two components: labour and non-labour costs. The following table details the Full Time Equivalents (FTEs) associated with the costs allocated by service and shows the split between labour and non-labour cost components.

Table 5.5 – 2013 FI FTEs, Labour and Non-labour Costs Allocated

Service	FTEs	Labour	Non-Labour	Total
Executive	5.0	4,778,000	-	4,778,000
Treasury and Taxation	2.0	361,000	116,000	477,000
Investor Relations	2.0	335,000	1,348,000	1,683,000
Financial Reporting	7.0	1,057,000	680,000	1,737,000
Internal Audit	1.1	290,000	461,000	751,000
Board of Directors	-	1,764,000	305,000	2,069,000
Other*	1.0	481,000	2,099,000	2,580,000
Less: Fortis Properties Management Fee Revenue	-	-	(1,500,000)	(1,500,000)
Total	**18.1**	**9,066,000**	**3,509,000**	**12,575,000**

* Certain non-labour costs such as consulting, legal, travel, accommodation and meals are captured in the "Other" category rather than separately identified within the following functions: Executive, Treasury, Investor Relations, Financial Reporting and Internal Audit.

FI Labour Costs

The labour costs include the following services:

- Executive
- Management
- Support staff
- Board of Directors

The labour costs include the following cost components:

- Base salary
- Bonus
- Employee benefits
- Board compensation

FI Non-Labour Costs

The non-labour costs include the following key components:

- Various external consulting services
- Travel and accommodation
- Insurance
- Legal
- Annual reporting
- Annual meeting
- External audit fee
- Public company filing and listing fees
- Transfer agent and trustee fees
- Bloomberg terminal fees and media release and monitoring fees, website maintenance costs
- Office supplies and expenses (including rent)
- Professional membership fees

5.6 FI Proportion of Total Assets

Once the cost allocation pool has been determined above, FI uses proportionate total assets as the allocator to allocate its recoverable operating costs to its subsidiaries based on the rationale that total assets are most closely related to the net investment required of FI in each subsidiary.

Management at both FI and FHI believe that allocation by asset base also better reflects the different types of utilities (i.e. gas and electric) invested in by FI rather than another type of allocator such as revenue or personnel costs of those utilities.

Based on December 31, 2013 forecast asset values in FI's 2013-2017 Business Plan, FHI represents 41.94% of the utility asset base to which costs will be allocated. (Note: Caribbean Utilities is excluded from the cost allocation as it has access to its own equity capital. Caribbean Utilities' assets; therefore, are excluded from the total asset pool for the purpose of the cost allocation).

5.7 FHI Portion of FI Recoverable Costs

After exclusions and the application of the revenues (refer Section 5.4 of this report), the net costs to be allocated to the utilities include the following categories as shown in table 5.7 below.

The net total corporate services cost pool of FI of $12,575,000, is allocated on a pro rata basis to the utilities based on the proportionate total asset base of each subsidiary. Based on December 31, 2013 forecast asset values in FI's 2013-2017 Business Plan, FHI represents 41.94% of the utility asset base to which FI costs are being allocated . This totals $5,273,000 based on the net total of $12,575,000 after FP Management Fee Revenue.

Table 5.7 – 2013 FI Management Fee Allocation

Service	FHI 41.94%	Other* 58.06%	Total
Executive	2,003,000	2,774,000	4,777,000
Treasury	200,000	277,000	477,000
Investor Relations	706,000	977,000	1,683,000
Financial Reporting	728,000	1,009,000	1,737,000
Internal Audit	315,000	436,000	751,000
Board of Directors	868,000	1,202,000	2,070,000
Other**	1,082,000	1,498,000	2,580,000
Subtotal	**5,902,000**	**8,173,000**	**14,075,000**
Less: Fortis Properties Management Fee Revenue	(629,000)	(871,000)	(1,500,000)
Total	**5,273,000**	**7,302,000**	**12,575,000**

*"Other" entities include: Belize Electricity, Belize Electric Company Limited, Fortis Turks and Caicos, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario (regulated and non-regulated).

** Other costs include: External consulting & legal, travel, meals and vehicle costs, insurance and office expenses.

6. Management's Corporate Cost Allocation Model – FortisBC Holdings Inc.

6.1 FHI Cost Allocation Model

Costs for corporate services allocated from FHI to FEU are calculated at the department level (i.e. Legal, Internal Audit). These cost pools are then allocated to FEU using a financial composite cost allocator commonly known as the Massachusetts Formula, described in Section 6.6 of this report. The following graphic provides a high level summary of how costs are allocated from FHI to FEU.

Figure 6.1 – FHI Cost Allocation Model

$$\left\{ \left\{ \boxed{\text{FHI Portion of FI Recoverable Operating Costs}} - \boxed{\text{FI Ineligible Expenses (see 6.2)}} \right\} + \left\{ \boxed{\text{FHI Operating Expenses (see 6.3)}} - \boxed{\text{FHI Specified Exclusions (see 6.4)}} \right\} \right\} \times \boxed{\text{Financial Composite Costs Driver (see 6.6)}} = \boxed{\text{FEU Portion of FHI Recoverable Operating Costs}}$$

6.2 FHI Portion of Recoverable Operating Costs and FI Ineligible Expenses

FHI is allocated a portion of the corporate services cost pools of FI (refer to Section 5 of this report). Of the total management fee being charged to FHI certain amounts are not recoverable operating costs. As previously determined by the Commission these costs are ineligible for inclusion in customer rates and are not passed on to the utilities.

Ineligible components of the FI management fee include Defined Benefit Supplemental Employee Retirement Plan and stock compensation costs which were not already excluded by FI. A reconciliation of the excluded costs from the Fortis Inc management fees is presented in the following table.

Table 6.2 – 2013 FI Management Fee Exclusions

	Total
Fortis Inc Management Fee	5,273,000
Less: Defined Benefit Supplemental Employee Retirement Plan costs	(214,000)
Less: Stock compensation costs not excluded by FI already	(651,000)
Total	**4,408,000**

6.3 FHI Operating Expenses

FHI provides management services to FEU that enable all companies to take advantage of the benefits that arise through economies of scale by providing certain services centrally. The services provided are outlined in the respective SLAs between FHI and the following entities:

- FHI and FortisBC Inc (FBC)
- FHI and FEI
- FHI and FEVI
- FHI and FEW

All business services as listed in the cost allocation model are commonly found in gas utilities. FHI's activities are focused on providing fiduciary services to FEU including the following primary activities noted in Table 6.3. (Note: this is not an exhaustive list).

Table 6.3 – FHI Management Services Description

Function	Activities Include
Board of Directors	• Ensure all continuous disclosure and governance activities required by external regulators and stakeholders and third parties are appropriately carried out, manage the relationship and corporate activities of the FHI Board of Directors, and develop and maintain governance procedures and policies. The Board of Directors is a joint Board that is shared with FortisBC Inc. All costs incurred for compensation and other Board expenses have been shared between FHI and FBC based on an expanded Massachusetts method which incorporates the operating revenue, payroll and average net book value of capital assets plus inventories. The costs reflected in this Application are the costs less any amounts recoverable from FortisBC Inc.
External Financial Reporting	• Preparation of monthly, quarterly and annual consolidated and non-consolidated financial statements (for FHI, FEI, FEVI and FEW), coordination with external auditors, analysis of financial information, assisting in the preparation of the Annual Information Form, quarterly and annual Management Discussion and Analysis and other continuous disclosure documents, coordinating consistent accounting policy treatment across the FEU, preparing for and implementing US GAAP changes, preparing quarterly forecasts of consolidated earnings and maintaining internal controls over financial reporting.
HR Compensation and Planning	• Consults with Management on the maintenance, development and governance of employees and retirees, provides assistance on annual wage and salary increases, ensure that employment practices are in compliance with applicable regulations and legislation.
Internal Audit	• Developing, planning and conducting audits/reviews, conducting annual risk assessment processes, monitoring and evaluating the effectiveness and efficiency of internal controls.
Legal	• Provides all legal services and counsel to various departments on issues including regulatory, environmental, business development, employment, securities, financing and intellectual property, and manages legal matters that have been outsourced to outside legal counsel.
Risk Management & Insurance	• Ensuring compliance with the TSX requirements on risk management, arranging for coverage based on assessed potential risk, and ensuring an appropriate and prudent insurance program.
Taxation	• Provides a full range of services in income and commodity taxes including financial reporting for taxes (year-end and quarterly tax provisions for current and future income taxes), tax compliance (filing of tax returns, coordination of tax audits), regulatory tax accounting (tax calculations for rate cases and annual reports), tax planning including guidance and support for significant transactions, and tax dispute management and resolution.
Treasury &, Cash Management	• Execute short and long term financings, cash management and forecasting, arrange operating credit facilities, and negotiate bank-service fees for all FEU entities; responsible for treasury related controls and compliance, compliance reporting, hedging of interest rate and foreign exchange risks, managing the rating agencies, maintaining bank and debt investor relationships, investor and shareholder communication, preparing regulatory submissions in support of ROE, capital structure and financing related matters, providing credit and counter-party credit risk management and assistance in negotiating physical and derivative commodity contracts to the Energy Supply and Resource Development department, assessment and monitoring of physical and financial counterparties, developing appropriate derivative and counterparty policies.
Facilities & Support	• Providing building space, shared services, computer software, office supplies and stationery, admin, computer outsourcing

In addition to the services listed in the table above, FHI allocates the recoverable portion of the FI management fee (total FI management fee less additional exclusions) to FEU.

6.4 Specified Exclusions

While FHI incurs costs in support of the utilities some costs are not eligible and have been excluded from the calculation of the FHI management fee. Costs excluded from FHI's 2013 recoverable operating costs are described as follows:

- All identifiable Business Development and Capital Management (shareholder related) costs:

  50% of time spent by one treasury department employee and the equivalent of 75% of a legal employee is devoted to business development activities and has been excluded from these corporate services cost pools.

  Management has determined the estimated internal labour costs and related benefits to be excluded based on an estimate of the time spent by each employee on business development activities.

- Legal and consulting fees incurred for non-regulated entities:

  Estimates of the time spent supporting non-regulated entities has been made for each corporate cost centre with labour and associated costs excluded for certain employees in the External Financial Reporting, Risk Management & Insurance, Taxation and Treasury & Cash Management divisions. The excluded amounts vary from 15% to 100% of the employee's cost of labour and associated benefits.

  Management has determined the estimated internal labour costs and related benefits to be excluded based on an estimate of the time spent by each employee on non-regulated entities. Management has estimated consulting fees related to activities on non-regulated entities based on historical cost levels.

- Pension bonus amounts for defined benefit supplemental pension plans;

  Based on previous determinations by the BCUC, pension bonus amount for defined benefit supplemental pension plans are ineligible for inclusion in customer rates and are not passed on to the utilities. Management have excluded these costs when calculating the fully loaded costs for employees of FHI.

- Services provided to FBC:

  Support service provided to FBC have been excluded in the corporate services cost pools. These exclusions have affected the labour costs relating to Internal Audit, Legal, Risk Management & Insurance, Taxation and Treasury & Cash Management.

  Management has determined the estimated internal labour costs and related benefits to be excluded based on an estimate of the time spent by each employee on FBC.

  All costs incurred for compensation and other Board expenses have been shared between FHI and FBC based on an expanded Massachusetts method which incorporates the operating revenue, payroll and average net book value of capital assets plus inventories. The costs reflected in this Application are the costs less any amounts recoverable from FortisBC Inc.

6.5 FHI Costs

Operating costs allocated from FHI to FEU include two components: labour and non-labour costs. The following table details the FTEs associated with the costs allocated by service and shows the split between labour and non-labour cost components. The table is based on 2013 FHI projected costs.

Table 6.5 – 2013 Projected FHI FTEs, Labour and Non-labour Costs Allocated

Corporate Services Cost Pool	FTE	Labour	Non-Labour	Total
Board of Directors	-	471,000	240,000	711,000
External Financial Reporting	4.3	695,000	472,000	1,167,000
HR Compensation and Planning	-	-	294,000	294,000
Internal Audit	4.0	511,000	263,000	774,000
Legal	9.8	1,693,000	248,000	1,941,000
Risk Management & Insurance	2.0	248,000	41,000	289,000
Taxation	4.4	934,000	85,000	1,019,000
Treasury & Cash Management	3.4	679,000	221,000	900,000
Facilities & Support	-	-	920,000	920,000
Fortis Inc. Management Fee	-	-	4,408,000	4,408,000
Total	**27.9**	**5,231,000**	**7,192,000**	**12,423,000**

FHI Labour Costs

The labour costs include the following:

- Executive
- Management
- Support staff
- Board of Directors

The labour costs include the following cost components:

- Base salary
- Bonus
- Employee benefits
- Board compensation

FHI Non-Labour Costs

The non-labour costs include the following key components:

- Various external consulting services
- External audit
- Board of Directors travel expenses
- Shared services
- Employee training
- Travel, accommodation and meals
- Office supplies
- Professional membership fees
- Legal library
- Computer software and hardware support
- Facilities

6.6 Financial Composite Costs Driver

FHI uses a variation of the Massachusetts Formula, a financial composite allocator, to determine the percentage of operating costs to be allocated from FHI to FEU. The Massachusetts Formula is a widely used and accepted financial composite cost allocator in the utility industry in North America as a method for allocating costs. It is calculated as an average of:

- Revenues
- Payroll; and
- Average NBV of tangible capital assets plus inventories.

FHI uses Gross Margin (revenue less cost of gas) in place of revenue in its application of the Massachusetts Formula for the following reasons:

- FEU does not earn a return on the commodity (gas) price therefore gross margin is used to compare the same elements in each utility;
- FEU does not earn a return on the sale of gas but rather on the distribution of gas so a reasonable and more stable measure of revenue is the margin; and
- Changes in consumption levels and changes in the commodity cost of natural gas do not materially impact earnings as a result of regulatory deferral accounts (i.e. any fluctuation in the cost of gas is recorded in a deferral account), and therefore revenue may not reflect the service provided or required.

Table 6.6 provides a summary of the cost allocator results that are consistent with Management's assessment principles in Section 4 of this report.

Table 6.6 – Financial Composite Formula Calculation as at December 31, 2012

	FEI	FEVI	FEW	Other*	Total
Gross Margin	$ 612,556,000	$ 140,114,000	$ 5,130,000	$ 1,200,000	$ 759,000,000
	80.7%	18.5%	0.7%	0.1%	100.0%
Payroll	$124,644,000	$ 9,742,000	$ 191,000	$ 2,898,000	$ 137,475,000
	90.7%	7.1%	0.1%	2.1%	100.0%
Average of NBV of PP&E + inventories	$ 2,727,333,000	$ 805,550,000	$ 14,292,000	$ 8,247,000	$ 3,555,422,000
	76.7%	22.7%	0.4%	0.2%	100.0%
Total (weighted)	82.7%	16.1%	0.4%	0. 8%	100.0%

* "Other" entities include Fortis Alternate Energy Services, Customer Works LP and several other smaller holding companies.

6.7 FEU Portion of FHI Recoverable Operating Costs

After exclusions and the application of the revenues stated above, the net costs to be allocated to the utilities include the following categories as shown in table 6.7 below.

The net total corporate services cost pool of FHI of $12,423,000, is allocated on a pro rata basis to the utilities based on the allocation results calculated using the Massachusetts Formula (refer to Section 6.6 of this report). This totals $10,273,000, $1,996,000 and $51,000 being allocated to FEI, FEVI and FEW, respectively.

Table 6.7 – 2013 FHI Management Fee Allocation

Corporate Services Cost Pool	FEI 82.7% (2009: 83.1%)	FEVI 16.1% (2009: 14.7%)	FEW 0.4% (2009: 0.4%)	Other 0.8% (2009: 1.8%)	Total
Board of Directors	588,000	114,000	3,000	6,000	711,000
External Financial Reporting	964,000	188,000	5,000	10,000	1,167,000
HR Compensation and Planning	244,000	47,000	1,000	2,000	294,000
Internal Audit	641,000	124,000	3,000	6,000	774,000
Legal	1,605,000	312,000	8,000	16,000	1,941,000
Risk Management & Insurance	240,000	46,000	1,000	2,000	289,000
Taxation	843,000	164,000	4,000	8,000	1,019,000
Treasury & Cash Management	743,000	145,000	4,000	8,000	900,000
Facilities & Support	760,000	148,000	4,000	8,000	920,000
Fortis Inc Management Fee	3,645,000	708,000	18,000	37,000	4,408,000
Total	**10,273,000**	**1,996,000**	**51,000**	**103,000**	**12,423,000**

* "Other" entities mainly includes FAES and other inactive entities.

7. KPMG Findings

7.1 Summary

KPMG is of the view that the corporate services cost pools and the cost allocators proposed for use in the FI and FHI corporate services cost allocation models both meet the internally generated objectives and evaluation criteria established by FI and FHI as detailed in Section 4 of this report, and as a result form a reasonable and objective basis of allocation.

7.2 Approach

This section summarizes KPMG's approach to conducting our evaluation of FI and FHI's corporate services cost allocation methodology using 2013 data.

Our work plan incorporated the following phases:

- **Phase 1: Launch.** In this phase, KPMG met with FI and FHI Management to obtain Management's initial estimates of cost pools and allocators, identified primary contacts and obtained other relevant information available from FI and FHI, respectively.
- **Phase 2: Cost Pools.** In this phase, KPMG performed the following:
    - Reviewed existing FI and FHI cost allocation methodology documentation, including current corporate services cost pools, process documentation, Commission correspondence, policy documentation, and peer group models, to the extent possible;
    - Reviewed the historic cost allocation models to gain an understanding of the cost allocators and the cost allocation process;
    - Obtained and discussed with FI and FHI Management its guiding principles for identifying appropriate corporate services cost pools. KPMG assessed the final corporate services cost pools against cost pool principles discussed in Section 4 of this report;
    - Obtained details of FI and FHI Management's proposed corporate services cost pools. Identified and reviewed and discussed the amounts and activities within corporate services cost pools prepared by FI and FHI, respectively, to determine whether the corporate services cost pools should be adjusted. As part of this procedure we reviewed job descriptions of individuals within the corporate services cost pools and conducted interviews with relevant FI and FHI Management and staff;
    - Discussed and reviewed general ledger budget costs which were not allocated to a corporate services cost pool with Management and divisional managers to assess if related costs were incurred for the benefit of FHI and FEU and should be included in the corporate services cost pools;
    - Reviewed corporate services cost pools, including labour and/or non-labour components, and discussed and reviewed costs to see if other general ledger costs were missing as they were associated with these activities and therefore should be included in these corporate services cost pools;
    - Reviewed personnel assigned to corporate services cost pools and enquired of Management if other individuals are associated with services benefiting FHI and FEU.
    - KPMG discussed organizational changes with Management that may change corporate services cost pools and assessed if changes to corporate services cost pools were made in response and were supported.

- **Phase 3: Review Allocation Methodologies and Cost Allocators.** In this phase, KPMG performed the following:
    - Compared the cost allocator(s) to historic cost allocators;
    - Evaluated the appropriateness of each cost allocator for allocation of cost pool expenditures against internal cost allocator principles (included in Section 4 of this report), including identification of options (where applicable), and their pros and cons;
    - Reviewed the information collected from FI and FHI's Time Allocation summaries or estimates if any, and:
        I. assessed the appropriateness of people included;
        II. assessed the quality of the information collected;
        III. assessed the results of allocating each cost pool with a labour component;
        IV. assessed the appropriateness of the time summaries or other evidence of time allocators (including questionnaires) as an allocator for the labour component of cost pools and in certain instances, the non-labour component of cost pools;
        V. assessed the method that Management utilized to determine the employee benefit expense load as part of the allocation of labour costs to cost pools and tested certain data on a sample basis;
    - Discussed with Management new cost allocators for non-labour related components of corporate services cost pools, the pros and cons of the recommended changes; and
    - Assessed Management's final cost allocators and assessed Management's resulting revised allocations, if any, for reasonableness.
- **Phase 4: Validate cost pools and cost allocators and methodology.** In this phase, KPMG performed the following:
    - Reconciled cost pools details to FI and FHI's 2013 budget figures from its 2012-2013 RRA.
    - For a sample of individuals in each cost pools, agree their roles to job descriptions or employee organizational charts;
    - Validated the mathematical accuracy of cost allocations and ensured that the allocators are consistent with the allocators noted in Phase 3; and
    - Checked the mathematical accuracy of the final updated allocation model. Re-performed allocations using the allocators and discussed the resulting allocation with Management to ensure the FHI and FEU cost allocation was reasonable when compared to the principles in Section 4 of this report.
- **Phase 5: Prepared report.** In this phase, KPMG prepared this report to summarize the results of the evaluation.

7.3 Procedures and Findings related to the Corporate Services Cost Pools, Cost Allocators and Cost Allocation Methodology

The following table in 7.3 reflect the KPMG procedures undertaken and findings on both the cost pool, cost allocators and methodology for both FI to FHI and for FHI to FEU.

Procedure	Findings - Management's Share Cost Allocation Model Fortis Inc.	Findings - Management's Share Cost Allocation Model FortisBC Holdings Inc.
7.3.1 Cost Pools		
1. Obtained existing cost allocation methodology documentation, including current corporate services cost pools, process documentation, Commission correspondence, and policy documentation.	Completed.	Completed.
2. Reviewed the historic and current proposed cost allocation model to gain an understanding of the cost allocators and the cost allocation process.	Completed. Proposed cost allocation pools are consistent with historic cost allocation pools.	Completed. The proposed costs pools used in FHI's corporate services cost allocation model have been amended to remove the "Other Compensation and Benefits" corporate services cost pool and included the fully loaded employee related costs in each of the cost pool individually. The below table details the impact of this reallocation between corporate services cost pools. The resulting change in cost pools did not impact the resulting allocation to FEU. The cross charging between FortisBC Inc and its affiliates based on fully loaded costs was approved by the Commission in its determination dated August 15, 2012 on the Application by FortisBC Inc for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan (Order No. G-110-12).

Procedure	Findings - Management's Share Cost Allocation Model Fortis Inc.	Findings - Management's Share Cost Allocation Model FortisBC Holdings Inc.

Change in Historical Cost Pools incorporated in the FHI corporate cost allocation.

Corporate Services Cost Pool	Total $ Value of Historic Cost Pool	Total $ Value of Proposed Cost Pool	Total $ Change in Cost Pool
Board of Directors	711,000	711,000	–
External Financial Reporting	955,000	1,167,000	212,000
HR Compensation and Planning	294,000	294,000	–
Internal Audit	595,000	774,000	179,000
Legal	1,334,000	1,941,000	607,000
Risk Management & Insurance	223,000	289,000	66,000
Taxation	791,000	1,019,000	228,000
Treasury & Cash Management	628,000	900,000	272,000
Facilities & Support	920,000	920,000	–
Other compensation and benefits	1,564,000	–	(1,564,000)
Fortis Inc Management Fee	4,408,000	4,408,000	–
Total	**12,423,000**	**12,423,000**	**–**

3. Obtained and discussed with Management its guiding principles for identifying appropriate corporate services cost pools.	Completed. Guiding principles are discussed in Section 4 of this report. Final proposed corporate services cost pools were concluded to be consistent with those principles.	Completed. Guiding principles are discussed in Section 4 of this report. Final proposed corporate services cost pools were concluded to be consistent with those principles.
4. Obtained details of Management's proposed corporate services cost pools. Reviewed and discussed the amounts and activities within corporate services cost pools to determine whether the corporate services cost pools should be adjusted. As part of this procedure we reviewed job descriptions of individuals within the corporate services cost pools and conducted interviews with relevant Management and staff.	Completed.	Completed.

Procedure	Findings - Management's Share Cost Allocation Model Fortis Inc.	Findings - Management's Share Cost Allocation Model FortisBC Holdings Inc.
5. Discussed and reviewed (general ledger) budget costs which were not allocated to a corporate services cost pool with Management and divisional managers to assess if related costs were incurred for the benefit of FEU and should be included in the corporate services cost pools.	Completed. No additional costs were noted. KPMG confirmed that services provided by FI are not duplicated in FHI or by any other source.	Completed. No additional costs were noted. KPMG confirmed that services provided by FHI are not duplicated in FEU or by any other source.
6. Reviewed corporate services cost pools, including labour and/or non-labour components, and discussed and reviewed costs to see if other general ledger costs were associated with these costs and therefore should be included in these corporate services cost pools.	Completed. No additional costs were noted.	Completed. No additional costs were noted.
7. Reviewed personnel assigned to corporate services cost pools and enquired of Management if other individuals are associated with services benefiting FHI and FEU, respectively.	Completed. No additional individuals were noted and as a result labour components were complete.	Completed. No additional individuals were noted and as a result labour components were complete.
8. KPMG discussed organizational changes with Management that may change corporate services cost pools and assessed if changes to cost pools were supported.	Completed	Completed
9. For one individual in each corporate services cost pool, agreed their roles to job descriptions, employee organizational charts.	Completed. No issues were noted.	Completed. No issues were noted.
10. Reconcile corporate services cost pools details to the 2013 O&M figures from the FEU's 2012-2013 RRA.	Completed. Amounts reconciled.	Completed. Amounts reconciled.
7.3.2 Cost Allocators and Cost Allocation Methodology		
1. Compared the cost allocator(s) to historical cost allocators.	Completed. No change in historical allocators.	Completed. No change in historical allocators.

<table>
<tr><th>Procedure</th><th>Findings - Management's Share Cost Allocation Model

Fortis Inc.</th><th>Findings - Management's Share Cost Allocation Model

FortisBC Holdings Inc.</th></tr>
<tr><td rowspan="2">2. Evaluated the appropriateness of each cost allocator for allocation of cost pool expenditures against internal cost allocator principles (included in Section 4 of this report), using the following assessment ratings:

S = satisfies the evaluation criteria
SS = somewhat satisfies the evaluation criteria
NS = does not satisfy the evaluation criteria</td><td>Completed.</td><td>Completed.</td></tr>
<tr><td colspan="2">
<table>
<tr><th>Evaluation Criteria</th><th>Assessment of total assets</th><th>Assessment of Massachusetts Formula</th></tr>
<tr><td>Cost Causality</td><td>S</td><td>S</td></tr>
<tr><td>Objective Results</td><td>S</td><td>S</td></tr>
<tr><td>Cost-Effectiveness</td><td>S</td><td>S</td></tr>
<tr><td>Stability over time</td><td>S</td><td>S</td></tr>
<tr><td>Transparent and Supportable Methodology</td><td>S</td><td>S</td></tr>
<tr><td>Regulatory Precedence</td><td>S</td><td>S</td></tr>
<tr><td>Distinguishable from Directly Allocated Costs</td><td>S</td><td>S</td></tr>
<tr><td>Accuracy of Underlying Data</td><td>S</td><td>S</td></tr>
<tr><td>Flexibility / Adaptability</td><td>S</td><td>S</td></tr>
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Procedure	Findings - Management's Share Cost Allocation Model Fortis Inc.	Findings - Management's Share Cost Allocation Model FortisBC Holdings Inc.
7.3.3 Labour Allocation and Employee Benefit Expense load rate applied to labour costs		
1. Reviewed the information collected from Time sheet summaries (employees internally charge their time to entities or groups of entities they work on) and assessed the quality of the information collected		
i. Assessed the appropriateness of people included in the cost pool and the resulting effective labour allocation. Obtained expected proportionate time estimates from staff through questionnaire and interviews; Obtained individual time allocations captured internally and assess if reasonable to be used and also if supported questionnaire time allocation estimates of the individuals;	N/A – FI employees are not required to complete timesheets. KPMG circulated questionnaires among the department heads for each cost pool and ensured employee time estimates noted in questionnaire responses did not significantly differ from the time allocation results based on the historical time allocators.	Completed. KPMG reviewed time records that are kept and also circulated questionnaires among the department heads for each cost pool. KPMG ensured employee time estimates noted in questionnaire responses did not significantly differ from the time allocation results based on the historical time allocators. Approximately 76% of time was common pool where the time and effort expended is for the benefit of all entities.
ii. Assessed and quantified how the labour costs were allocated from each cost pool with a labour component;		Completed.
iii. Compare the questionnaire allocation results to the ultimate allocation and discuss with employees and Management.		Completed.

Procedure	Findings - Management's Share Cost Allocation Model Fortis Inc.	Findings - Management's Share Cost Allocation Model FortisBC Holdings Inc.
2. Assessed the method that Management utilized in order to determine the employee benefit expense load as part of the allocation of labour costs to the corporate services cost pools and tested certain data on a sample basis. The employee benefit expense load includes the following more significant benefits that are added to the cost basis of labour and then corporate between entities - Life and disability premium costs - Medical and dental - Savings and pension plan - CPP and EI	Completed. KPMG finds that the employee benefit expense load rate applied to labour costs charged to be relevant and appropriate to include based upon the sample procedures performed.	Completed. KPMG finds that the employee benefit expense load rate applied to labour costs charged to be relevant and appropriate to include based upon the sample procedures performed.
3. Discussed alternate cost allocators with Management and the pros and cons of the recommended changes.	KPMG reviewed alternate allocators that might be used from those noted in Section 5 and 6, but the results of these allocators do not produce a significant (greater than 5.5%) allocation variance from those results as stated.	
4. Obtain from Management, back-up documentation (i.e. audited financial statements) to support the numbers in the non-time allocation methods (total assets and total investment).	Completed	Completed
7.3.4 Final Report		
1. Ensured Management's final cost allocators are aligned with the working steps outlined in steps 7.2 above.	Completed. Final cost allocators reflect all discussions and assessments with Management and are consistent with internal assessment principles.	Completed. Final cost allocators reflect all discussions and assessments with Management and are consistent with internal assessment principles.
2. Validated the mathematical accuracy of the final updated allocation model, using cost pool figures derived from FEU's 2012-2013 RRA. Re-performed allocations using the final cost allocators and discussed the resulting allocation with Management to ensure the allocation was reasonable in nature and amount.	Completed. No issues noted. See the resulting allocations in the table 5.7.	Completed. No issues noted. See the resulting allocations in the table 6.7.

7.4 KPMG Conclusion – Corporate Services Cost Allocation

Based on the results of the above specified procedures, KPMG is of the view that the corporate services cost pools and the cost allocators proposed for use in the FI and FHI corporate services cost allocation models both meet the internally generated objectives and evaluation criteria established by FI and FHI as detailed in Section 4 of this report, and as a result form a reasonable and objective basis of allocation.

THIS AGREEMENT is made effective January 1, 2010.

BETWEEN:

TERASEN GAS INC., a corporation formed under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia

("TGI")

AND:

TERASEN INC., a corporation formed under the laws of British Columbia, having an office at 10th Floor, 1111 West Georgia Street, Vancouver, British Columbia

("Terasen")

WHEREAS

A. TGI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of the Lower Mainland and the Interior;

B. TGI maintains its administrative offices in the City of Surrey; and

C. TGI wishes to retain Terasen to provide certain professional and management services to it in respect to the ownership and operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES THAT, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international,

judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the professional and management services to be provided to TGI by Terasen as more particularly described in Section 2.1.

1.2 Schedules

Schedule "A" is attached to, and is incorporated by reference into, this Agreement.

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,
2) any reference in this Agreement to a designated "Article", "section" or other subdivision is to the designated Article, section or other subdivision of this Agreement,
3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision,
4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,
5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and
6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

1.5 Prior Agreements

The parties agree that any prior agreements between the parties pertaining to the subject matter hereof, including the agreement effective January 1, 2004 and any amendments, including the amending agreement effective December 31, 2006, are hereby cancelled and of no further effect.

PART 2

SERVICES

2.1 Services

Terasen hereby agrees to provide to TGI those professional and management services described in Schedule "A" which Services shall include certain professional and management services provided to Terasen by its parent company, Fortis Inc which professional and management services also benefit TGI.

2.2 No Obligation to Provide Additional Services

Terasen shall not perform, and Terasen shall have no obligation to perform, any services on behalf of TGI other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGI

Terasen will consult with TGI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between Terasen and TGI. In performing the Services, Terasen shall be an independent contractor. Terasen employees shall not be considered employees of TGI for any purpose.

2.5 Compliance

In performing the Services, Terasen will comply with all Applicable Laws.

PART 3

COMPENSATION

3.1 Compensation for Services and Shared Costs

TGI agrees to pay to Terasen for the Services to be provided and for a proportionate share of the common expenses incurred by Terasen such as shareholder expenses and director compensation the amount of $9,022,000 per annum on a take-or-pay basis.

3.2 Amendment to Costs

The amounts set out in Section 3.1 may be amended annually by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGI and to reflect annual inflationary adjustments. Any services to be provided that are not contemplated under this Agreement will be subject to additional compensation as agreed between the parties and form an amendment to this agreement in accordance with Section 10.3 below.

3.3 Invoicing

Terasen will invoice TGI in respect of the Services no later than the 25^{th} day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

TGI will, within thirty (30) days of receipt of an invoice from Terasen, pay to Terasen the amount specified in such invoice. Any amount to be remitted by TGI to Terasen and not remitted on or before the date on which it is due shall thereafter bear interest. A late payment charge of 1.5% per month (18% per annum) shall be payable to Terasen on any unpaid balance after thirty (30) days of the date of invoice.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGI

Subject to Section 4.4, TGI will indemnify, defend and hold harmless Terasen and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with Terasen's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of Terasen.

4.2 Limitation of Liability of Terasen

Neither Terasen nor any of its directors, officers, employees, agents or contractors will be liable to TGI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with Terasen's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of Terasen.

4.3 Indemnity by Terasen

Subject to Section 4.4, Terasen will indemnify, defend and hold harmless TGI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGI may suffer or incur as a result of any act or omission or error of judgement as a result of which Terasen is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF TGI

5.1 Covenants by TGI

TGI covenants and agrees to:

(a) fully co-operate with Terasen in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGI to Terasen or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of Terasen

Terasen hereby represents and warrants to TGI as representations and warranties which are true as at the date hereof and which will be true during the term of Terasen's appointment hereunder:

(a) Terasen is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and Terasen has full power and authority to perform its obligations hereunder;

(b) this Agreement constitutes a valid and binding obligation of Terasen enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) Terasen possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGI

TGI hereby represents and warrants to Terasen as representations and warranties which are true as at the date hereof and which will be true during the term of Terasen's appointment hereunder

(a) TGI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2010 and will end on December 31, 2010, unless earlier terminated pursuant to the provisions hereof. Thereafter this Agreement will automatically be renewed for further one (1) year terms subject to Section 7.2 below.

7.2 Termination

Terasen's appointment hereunder may be terminated at any time:

(a) by Terasen giving TGI six (6) months' written notice of such termination:

(i) if TGI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event TGI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGI of written notice thereof from Terasen or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from Terasen and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of Terasen that TGI is in breach is conceded to be correct by TGI or found to be correct by an arbitrator pursuant to section 8.1;

(b) by TGI giving Terasen six (6) months' written notice of such termination:

(i) if Terasen becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if Terasen makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against Terasen seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of Terasen or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or Terasen consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event Terasen breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by Terasen of written notice thereof from TGI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGI that Terasen is in breach is conceded to be correct by Terasen or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, Terasen will have no further obligations under Article 2 and will promptly deliver to TGI any material documents in the possession of Terasen pertaining to the business of TGI.

7.4 Compensation of Terasen on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGI will pay to Terasen all amounts owing to Terasen hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this section, the fees provided for in Article 3 which are payable to Terasen on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between Terasen and TGI regarding any allegation that TGI or Terasen is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

[Execution page follows]

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on June 24, 2009.

TERASEN GAS INC.

By: ______________________________
Scott A. Thomson

Title: VP, Regulatory Affairs & CFO

TERASEN INC.

By: ______________________________
Roger Dall'Antonia

Title: VP, Corporate Development & Treasurer

Schedule "A"

Description of Services

SERVICES PROVIDED BY TERASEN

General Governance & Oversight Services

In addition to the specific services described below, TGI receives the benefit of the expert advice and experience of Terasen executives, who spend their time working on various committees including the Executive Committee (comprised of the CEO and senior vice presidents of Terasen as well as the heads of each operating company and the General Counsel), the Risk Management Committee and the Operating Committee.

Treasury and Cash Management

(1) Execute Financings
- a. Develop financing plans
  - i. Provide assessments of financing alternatives
  - ii. Determine timing, term, rate, structure
- b. Obtain BCUC approvals
- c. Execute financings
  - i. Negotiation, preparation of legal documentation
  - ii. Prepare disclosure documentation
  - iii. Investor presentations
  - iv. Due diligence process
  - v. Deal execution

(2) Cash Management
- a. Prepare and maintain short-term cash forecasting
- b. Execute short-term borrowing
  - i. Commercial paper issuance
  - ii. Bank borrowing
- c. Execute short-term investing of excess funds
- d. Negotiation of letters of credit
- e. Execution of manual wire transfers
- f. Establish and maintain internet based banking platform for cp issuance, fund transfers and reporting

g. Payment of interest, principal and fees on outstanding debt

(3) Arrange operating credit facilities

a. Negotiate credit agreements

i. Determine terms and conditions

ii. Negotiate pricing and term

b. Manage syndication process

c. Obtain BCUC approval

(4) Negotiate bank-service fees

(5) Treasury-related controls and compliance

a. Develop and monitor control and compliance procedures for key Treasury procedures

(6) Compliance reporting

a. Prepare and file required compliance reports with third parties

i. Lenders, securities commissions, BCUC

(7) Hedging of interest rate and foreign exchange risks

a. Develop financial hedging plans as required

b. Negotiation of required documentation

c. Execution of derivative transaction

(8) Prepare Derivatives Policies and Procedures;

(9) Counterparty Credit Risk Management;

a. Review credit worthiness of counterparties

b. Determine appropriate credit limits for counterparties

c. Determine requirement for credit support

d. Negotiate appropriate credit support documentation

(10) Interest rate and foreign exchange rate forecasting;

(11) Regulatory submissions with respect to ROE, capital structure and financing matters;

(12) Capital structure review and maintenance; and

(13) Provide education and related materials from training courses and seminars attended by Treasury staff.

Investor Relations

(1) Manage the Rating Agency Process;

(2) Maintain investment banker and debt investor relationships;

(3) Maintain banking and money market dealer relationships;

(4) Investor and Shareholder communication;

(5) Assist in preparation of annual/quarterly disclosure documents; and

(6) Prepare annual report.

Corporate Development and Capital Management

(1) Manage the annual strategic planning cycle;

(2) Preparation and maintenance of the five year forecasting model used for strategic planning process and in the annual budgeting process;

(3) Provide financial analysis and evaluation of new projects and new initiatives;

(4) Manage the acquisition and divestiture activity;

(5) Provide project management and/or due diligence support where required; and

(6) Contract negotiation in support of business development initiatives.

External Reporting and Consolidation

(1) Consolidation and preparation of monthly financial statements for TGI and preparation of quarterly interim reports and annual audited financial statements;

(2) Preparation of monthly reporting journal entries (consolidation, tax, accruals, etc), analytical reviews of accounts and monthly financial review package

(3) Preparation of analysis required from prospectus and other security filing documents as requested by Treasury Department and senior management;

(4) Preparation of quarterly and annual report to the Audit Committee;

(5) Compilation of information in response to a variety of enquiries from operations, senior management and external bodies, such as the BCUC, external auditors and government agencies;

(6) Research current and emerging accounting policies in Canada, the US and under International Financial Reporting ("IFRS");

(7) Direct response to accounting authorities in both Canada, the US and IFRS with respect to exposure drafts and pronouncements;

(8) Project lead for Terasen on the implementation of IFRS;

(9) Provide accounting policy advice for such issues as consistency of presentation, alternative treatments and resolution of complicated accounting policies and ensure compliance with General Accepted Accounting Principles;

(10) Accounting advice and assistance as required.

Taxation Services

(1) Prepare year-end and quarterly tax provisions including preparing tax calculations and working papers for current tax expense, providing information for the calculation of FIT expense and reviewing FIT calculations, preparing or reviewing the necessary journal entries, assisting auditors with external audit review, preparing tax disclosures to the financial statements and analyzing Balance Sheet tax accounts;

(2) Prepare tax returns and all tax compliance work for TGI, including identification and research of technical issues, filing necessary elections, agreements and information returns, requesting post filing adjustments, and reviewing assessments and interest calculations;

(3) Calculate corporate tax instalments and arrange payment;

(4) Prepare or review tax information and calculations in support of rate cases, annual reviews and annual reports to the BCUC; participate in regulatory working groups to provide information and guidance on tax issues;

(5) Provide tax support for planning and forecasting groups; provide a strategic tax perspective into planning processes to optimize tax advantages for the Gas companies;

(6) Provide leadership, guidance and consultation to finance and operations leaders on income tax and commodity tax issues; find tax solutions to complex business issues;

(7) Monitor, identify and research tax issues resulting from tax law changes, accounting changes (such as IFRS) or business opportunities to make sound recommendations to management;

(8) Interpret impact of industry issues on tax; participate in industry group tax committees such as Canadian Gas Association and make submissions to government bodies on issues relevant to the industry;

(9) Monitor GST and PST (including Social Services Tax, Carbon Tax, ICE levy), including identifying issues and researching technical enquiries, coordinating filing of necessary elections, responding to queries on the application of GST or PST to particular transactions, training employees on the application of commodity taxes to revenues,

disbursements and transactions, advising employees of commodity tax changes; advising in the implementation of new taxes;

(10) Monitor tax implications of payroll and employee benefits including advising on taxable benefits and related calculations, payroll tax issues, and pension plan tax issues;

(11) Coordinate tax audits (federal income tax, LCT, GST , various PST), provide auditors access to data, research and provide answers to auditor's requests and negotiable beneficial resolution of proposed adjustments;

(12) Prepare and file Notices of Objection and Appeal letters and coordinate legal appeals with internal and .external counsel; negotiate with tax authorities with a view to minimizing ultimate liabilities;

(13) Establish and monitor tax department controls and ensure adherence to tax policies;

(14) Provide ongoing training, guidance and support to tax group employees to enhance their performance levels and career development.

Internal Audit

(1) Develop, plan and conduct audits/reviews of areas or processes of particular interest or of identified risk and prepare internal audit reports;

(2) Conduct annual risks assessment process in conjunction with the Enterprise Risk Management group;

(3) Monitor and evaluate the effectiveness and efficiency of controls throughout the year and summarize results to the Audit Committee of the Board of Directors;

(4) Ensure that the TGI Code of Business Conduct compliance management is effective by conducting the annual compliance reviews and acting as a resource when issues arise with respect to the Code of Business Conduct;

(5) Monitor the Whistle Blower Ethics line and address issues as they arise;

(6) Participate on various committees in the capacity of ex-officio to provide oversight and value add;

(7) Undertake work at the request of the BC Utilities Commission regarding the activities and operations of TGI.

(8) Provide annual reports summarizing Internal Audit activities and findings to the BCUC as well as other reports of regulatory compliance;

(9) Conduct post implementation reviews of major capital projects and acquisitions and report results to the Audit Committee;

(10) Provide assistance to the external auditors in completing their external financial audits; and

(11) Coordinate activities of various internal and external assurance providers to ensure proper coverage and minimize duplication of efforts.

Risk Management and Insurance Services

(1) Ensure compliance with the TSX requirements on risk management by ensuring that the Board of Directors understand the principal risks of all aspects of business that TGI is engaged in, and ensuring that there are systems in place that effectively manage and monitor those risks with a view to the long term viability of the TGI;

(2) Arrange for coverage based on assessed potential risk of damage or loss in asset values, disruptions in operations or potential legal liabilities;

(3) Advise dollar value of coverage required, most appropriate coverage and proper services required;

(4) Provide a single insurance program to achieve economies of scales and cost reductions;

(5) Work with broker in negotiating renewals and adequacy of coverage;

(6) Ensure competitive terms and consider all available options;

(7) Establish procedures and provide assistance and guidance in the reporting, handling, compiling, negotiating and settlement of claims;

(8) Provide mechanism for appropriate and timely local resolution of third party damage claims below a given threshold and payment of same;

(9) Conduct of review of contractual agreements to protect TGI from unnecessary assumption of risks;

(10) Coordinate Risk Management's group participating in industry associations and education seminars;

(11) Establish loss control standards to help ensure consistent and high degree of loss; prevention in all operating units and minimize impact when they do occur;

(12) Ensure familiarity with policies and wordings;

(13) Encourage and establish procedures for loss control;

(14) Administer Certificates of Insurance;

(15) Preparation of management reports;

(16) Provide additional insurance for individual construction projects, as required; and

(17) Provide bonding as required.

Corporate Secretary's Office

(1) Ensure all continuous disclosure and governance activities required by external regulators and third parties are appropriately carried out, including Securities filings and BC Business Corporations Act requirements; and

(2) Manage the relationship and corporate activities of the Board of Directors.

(3) Prepare materials for Board of Directors and minutes.

(4) Track and maintain corporate records.

(5) Assist in preparation of corporate documentation and providing corporate information to internal and external parties.

Legal Department

(1) Provide all legal services to TGI other than those outsourced to outside legal counsel;

(2) Direct the provision and management of outside legal services, primarily litigation, to TGI;

(3) Provide management of all litigation;

(4) Provide legal counsel on regulatory, environmental, marketing, employment, and intellectual property;

(5) Ensure legal compliance for press release, financial reports and other disclosure documents;

(6) Advise TGI on legal issues that may arise including claims, actions, real estate and other property transactions, and contracts, including the purchase of goods and services by TGI; and

(7) Provide general miscellaneous legal support and advice to management.

Human Resources Compensation and Planning

(1) Consult with management on the maintenance, development and governance of employees and retiree benefit programs, pension plans, employee savings plans and employee assistance programs;

(2) Provide assistance on annual wage and salary increases, providing labour market comparisons, establishing and implementing ad hoc increases for long term disability and pension recipients;

(3) Ensure that employment practices are in compliance with applicable regulations and legislation through development and administration of appropriate corporate policies and procedures;

(4) Consulting and direction on disability management guidelines and policy;

(5) Oversee the annual preparation of the executive succession plan and present the plan to the Management Resources Committee and to the Board of Directors;

(6) Corporate governance and direction regarding benefits carriers, benefits and pension consultants, financial services providers;

(7) Corporate reporting to legislative bodies, CCRA, Statistics Canada, Pension Standards, as required; and

(8) Corporate governance of salary and benefit administration, including executive and management compensation.

SERVICES PROVIDED BY FORTIS INC. ("FORTIS")

Executive Function

President & CEO

A. *Strategic Direction*

1. Present annually to the Board of Directors of Fortis (the "Board") a strategic plan and a business plan which must (a) be designed to achieve the corporate objectives together with an appropriate set of performance measures, (b) identify the principal strategic and operational risks of the business, and (c) include appropriate methods to manage the risks;
2. Obtain Board approval for the strategic plan and the business plans of Fortis as a precondition to the implementation of such plans;
3. Obtain Board approval for the procurement, allocation, and disposition of corporate resources for Fortis as a precondition to such procurement, allocation or disposition of such resources either;
   a. in the approved Business Plan; or
   b. by specific authorization of an asset transaction consistent with current business activities in an amount in excess of $XX [insert amount] million ($XX [insert amount] million annual aggregate) and for any share transaction (other than increased investment in an existing affiliate within the transaction size parameters noted above); and
4. Communicate the principal objectives and strategic plan for Fortis throughout Fortis.

B. *Leadership and Management of Fortis*

1. Lead Fortis with vision and values that are well understood, widely supported and consistently followed;
2. Foster a corporate culture which promotes ethical practices, personal integrity and the fulfilment of social responsibilities;
3. Create the appropriate environment to stimulate employee morale and productivity;
4. Manage change proactively;
5. Ensure continuous improvement in the quality and value of the products and services provided by Fortis;
6. Ensure that Fortis achieves and maintains satisfactory competitive positions within its industries; and

7. Serve as a director of Fortis.

C. *Management and Organization Structure*

1. Provide advice to the Board on the appointment of all officers of Fortis;
2. Assist the Board in establishing the limits of delegated authority and responsibility in conducting Fortis's business;
3. Provide annually to the Board, an evaluation of the performance of each senior manager who reports to the CEO;
4. Present for approval to the Board, an annual plan which will provide for the development and succession of senior managers of Fortis in a timely fashion;
5. Generally develop, attract, and retain a highly motivated, effective management team; and
6. Obtain Board approval for any proposed significant or material change in the organizational structure of Fortis as a precondition to the implementation of such changes.

D. *Finances, Controls and Internal Systems*

1. Consistently strive to achieve Fortis's annual and long-term financial goals and objectives;
2. Assist the Board in establishing an appropriate capital structure for Fortis;
3. Ensure that Fortis has systems in place to effectively monitor and manage the principal risks related to the operation of the business(es);
4. Establish and maintain the integrity of Fortis's financial controls and reporting systems and compliance of the financial information with appropriate accounting principles;
5. Establish and monitor processes and systems designed to ensure compliance with all applicable laws by Fortis, its officers and employees; and
6. Provide certification of financial matters, including the completeness and accuracy of Fortis's financial statements and, where necessary, matters relating to internal controls over financial reporting.

E. *Employee Relations*

1. Ensure that a process is in place to monitor compliance with the ethical standards to be observed by all officers and employees of Fortis, and ensure that a process is in place to monitor divergence from the ethical standards to be observed by all employees; and
2. Establish and maintain effective communications with employees of Fortis.

F. External Communication

1. Assist the Board in establishing and maintaining an effective communications policy with shareholders, the financial community, the media, the community at large and other stakeholders;
2. Ensure that Fortis contributes, and is perceived to contribute, to the well-being of the communities it serves; and
3. Serve as the principal representative and spokesperson of Fortis.

G. Board Relations

1. Keep the Board adequately informed, on a timely basis, with respect to all events and information which the CEO believes might materially affect Fortis, its performance, prospects, and image;
2. Provide the assistance necessary for the Chair of the Board and committees of the Board to carry out their duties;
3. Be entitled to attend all meetings of Board committees and provide Board committees the assistance necessary to carry out their mandates;
4. Assist the Board in reviewing and maintaining an up-to-date position description for the President and CEO of Fortis; and
5. Report to the Board on material use of outside consultants.

VP Finance and CFO

1. Advise and assist the Chairman of the Board and President and CEO in the development of strategies and goals in the financial planning and structure of the Group and in the control of the Company's business operations.
2. Keep the CEO informed of all relevant financial information and report on the financial status and performance of all companies in the group to the Board of Directors of Fortis Inc.
3. Responsible for all aspects of investor relations program, including shareholder communications and shareholder meetings.
4. Liaison with the investment community and market surveillance.
5. Ensure that procedures and systems necessary to maintain proper records and to afford adequate accounting controls and services are implemented throughout the organization.
6. Ensure that uniform financial policies and procedures are adhered to throughout the organization.
7. Ensure the development and maintenance of timely financial information systems.

8. Develop and maintain effective internal and external audit activities and recommend proper financial controls.
9. Develop and maintain suitable budgeting procedures and reviews.
10. Direct the planning and control of corporate cash requirements and major banking relationships.
11. Review capital expenditure plans and budgeting.
12. Plan and direct corporate financing.
13. Recommend guidelines for financial transactions between companies in the Fortis Group.
14. Ensure that adequate financial personnel resources are retained and appropriately assigned throughout the group.
15. Appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions. As demanded, manage external financial consulting resources.
16. Maintain an awareness of changes in practice and procedure within the professional accounting field.
17. Act as CFO of subsidiary organizations when required.

General Counsel & Corporate Secretary

1. Prepare schedules, notices, agendas, resolutions, and minutes for the Boards of Directors of Fortis Inc. and selected subsidiaries and affiliates.
2. Coordination of all communications to Board of Directors.
3. Operation of share purchase plans.
4. Preparation of security documents including Management Information Circulars, Annual Information Forms and prospectuses.
5. Responsible for regulatory compliance, including annual returns to the registries of companies, dividend disclosure, filing of annual and quarterly reports, reports to stock exchanges, notices of Material Change, and Insider Reports.
6. Provide legal services to all corporations in the Fortis Group including, when necessary, engagement of outside legal services.

Treasury and Taxation Function

1. Manage equity financing, including both common and preference shares, and related prospectuses

2. Manage debt financing, including long-term debt and credit facility borrowings as well as borrowing rates
3. Maintaining the capital structure
4. Assist the VP finance and CFO appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions
5. Cash management and forecasting activities – including dividend and interest payments and equity injections required by subsidiaries
6. Managing cash requirements of subsidiaries, as required, as it relates to intercompany loans and required equity injections
7. Debt covenant calculations and monitoring
8. Managing hedging activities related to US dollar debt
9. Preparation of annual corporate tax returns and related foreign affiliate corporate tax returns
10. Calculation of quarterly and annual Fortis Inc. corporate tax provision
11. Responsibility for utilization of non-capital and capital loss carryforwards of Fortis Inc. and coordination of tax utilization plans with applicable subsidiaries
12. Managing corporate reorganizations and tax planning
13. Manage tax implications of payroll and employee benefits including researching and advising on taxable benefits, CPP, EI and payroll tax issues
14. Preparing Fortis Inc. employee T4's, including preparing taxable benefit calculations
15. Coordination of Fortis Inc. corporate income tax or HST audits
16. Tax research associated with tax issues and changes in tax laws

Investor Relations Function

1. Manage analyst communications – including review of analysts' commentaries/research reports, conduct quarterly conference calls and respond to general analyst research inquiries.
2. Manage investor communications – including the preparation and delivery of investor presentations, road shows, web casts, teleconferences and one-on-one meetings with existing and prospective shareholders
3. Manage shareholder communications – including responding to general shareholder inquiries and the preparation, delivery and filing of documentation for quarterly and annual mailings (i.e., quarterly reports, annual report, proxy, management information circular and annual information form).

4. Coordination and preparation of Fortis's Annual Meeting including preparation of the Executive's presentation to shareholders.
5. Coordination of solicitation of proxies.
6. Preparation of Quarterly Investor Relations Reports to the Board of Directors.
7. Preparation, coordination and dissemination of media releases to newswire agencies, websites and distribution lists.
8. Monitor and maintain Fortis's media coverage.
9. Develop, host and maintain the Fortis Inc. website.
10. Monitor the websites of the Fortis Group of Companies.
11. Monitor and research the market and investment community through Bloomberg, ThomsonOne, TSX, etc.
12. Manage and maintain the Fortis Inc. dividend reinvestment and share purchase plans (i.e., Dividend Reinvestment and Share Purchase Plan, Consumer Share Purchase Plan and Employee Share Purchase Plan)
13. Coordination and preparation of Fortis's consolidated Strategic Issues document and presentation to the Board of Directors.
14. Preparation of Fortis's consolidated Business Plan presentation to the Board of Directors.
15. Manage public relations – including conference participation, the preparation of Executive speeches and responding to media inquiries.

<u>Financial Reporting Function</u>

1. Preparation of quarterly and annual consolidated financial statements and notes to the financial statements and the related management discussion and analysis
2. Preparation of monthly internal consolidated and non-consolidated financial statements of Fortis Inc.
3. Coordination with external auditors of the annual audit of the consolidated financial statements and quarterly review of consolidated financial statements.
4. Preparation and analysis of financial information required for prospectus and other security filing documents
5. Preparation of the Annual Information Form and providing assistance in the preparation of the Management Information Circular
6. Assisting in responding to reviews and queries of securities regulators related to continuous disclosure reporting

7. Research current and emerging accounting policies in Canada, US and that related to IFRS
8. Coordinate consistent accounting policy treatment across the Fortis group of companies related to presentation, alternative treatments and resolution of complex accounting policies to ensure compliance with GAAP
9. Oversight and coordination of conversion to International Financial Reporting Standards across the Fortis Group of companies – including coordinating research, organizing working group and steering committee sessions to discuss and resolve ongoing issues and progress, monitoring and directing progress of the overall conversion and coordination with the external auditors
10. Coordination and preparation of consolidated Business Plan document and reporting to the Board of Directors
11. Preparation of quarterly forecasted consolidated earnings and EPS
12. Responsibility for maintaining internal controls over financial reporting at Fortis Inc.

<u>Internal Audit Function</u>

1. Performs internal audit activities at Fortis Inc including:
   a. coordinating the Fortis Inc. CEO and CFO internal controls certification process through maintenance of financial process documentation and annual evaluation of internal controls over financial reporting and disclosure controls. Involves ensuring that all Fortis subsidiaries are fully compliant in order to support certification by the parent company;
   b. performing quality assurance reviews of Fortis Inc. continuous disclosures documents prior to public filing;
   c. performing annual reviews of Fortis Inc. statutory obligations and executive expenditures;
   d. reporting internal audit activities to the Fortis Inc. Audit Committee on a regular basis; and
   e. coordinating compliance with corporate governance requirements

2. Provides oversight over the internal audit function at the Fortis subsidiary companies to:
   a. ensure corporate-wide consistency in the application of internal audit methodologies and practices and in the reporting of audit results to management and audit committees;

   b. coordinate annual audit program planning to ensure critical risk areas are addressed;
   c. coordinate corporate-wide audit projects;
   d. identify opportunities for audit resource and information sharing between the subsidiary internal audit groups;
   e. oversees audit program planning and reviews internal audit reports to management and Audit Committees for these subsidiaries with limited internal audit resources;

3. Administers and monitors reports of allegations of suspected improper conduct or wrong doing via Fortis's ethics reporting system
4. Development of a company-wide Enterprise Risk Management program approach

<u>Board of Directors</u>

The Board of Directors of Fortis Inc. is responsible for the stewardship of Fortis. The Board will supervise the management of the business and affairs of Fortis and, in particular, will:

A. *Strategic Planning and Risk Management*

1. Adopt a strategic planning process and approve, on an annual basis, a strategic plan for Fortis which considers, among other things, the opportunities and risks of the business;
2. Monitor the implementation and effectiveness of the approved strategic and business plan;
3. Assist the CEO in identifying the principal risks of Fortis's business and the implementation of appropriate systems to manage such risks;

B. *Management and Human Resources*

1. Select, appoint and evaluate the CEO, and determine the terms of the CEO's employment with Fortis;
2. In consultation with the CEO, appoint all officers of Fortis and determine the terms of employment, training, development and succession of senior management (including the processes for appointing, training and evaluating senior management);
3. To the extent feasible, satisfy itself as to the integrity of the CEO and other officers and the creation of a culture of integrity throughout Fortis;

C. *Finances, Controls and Internal Systems*

1. Review and approve all material transactions including acquisitions, divestitures, dividends, capital allocations, expenditures and other transactions which exceed threshold amounts set by the Board (including equity contributions to subsidiaries to support the investment in rate base to serve customers;
2. Evaluate Fortis's internal controls relating to financial and management information systems;

D. *Communications*

1. Adopt a communication policy that seeks to ensure that effective communications, including statutory communication and disclosure, are established and maintained with employees, shareholders, the financial community, the media, the community at large and other security holders of Fortis;
2. Establish procedures to receive feedback from stakeholders of Fortis and communications to the independent directors as a group;

E. *Governance*

1. Develop Fortis's approach to corporate governance issues, principles practices and disclosure;
2. Establish appropriate procedures to evaluate director independence standards and allow the Board to function independently of management;
3. Appoint from among the directors an audit committee and such other committees of the Board as deemed appropriate and delegate responsibilities thereto in accordance with their mandates;
4. Develop and monitor policies governing the operation of subsidiaries through exercise of Fortis's shareholder positions in such subsidiaries;
5. Develop and monitor compliance with Fortis's code of conduct;
6. Set expectations and responsibilities of directors, including attendance at, preparation for and participation in meetings; and
7. Evaluate and review the performance of the Board, each of its committees and its members.

THIS AMENDING AGREEMENT is made effective January 1, 2012 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY INC.
(formerly Terasen Gas Inc.)
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEI")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
(formerly Terasen Inc.)
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEI and FHI entered into an agreement dated as of January 1, 2010 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. All references to "Terasen Gas Inc." and "TGI" shall be deleted and replaced with "FortisBC Energy Inc." and "FEI" respectively.

3. All references to "Terasen Inc." and "Terasen" shall be deleted and replaced with "FortisBC Holdings Inc." and "FHI" respectively.

4. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $10,719,700 per annum for the period of January 1, 2012 to December 31, 2012 on a take-or-pay basis and the amount of $11,030,900 per annum for the period of January 1, 2013 to December 31, 2013 on a take-or-pay basis."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

7. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

8. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

9. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY INC.

By: ____________________

Roger Dall'Antonia

Title: Vice President, Finance & CFO

FORTISBC HOLDINGS INC.

By: ____________________

Scott Thomson

Title: Executive Vice President, Finance, Regulatory & Energy Supply

THIS AMENDING AGREEMENT #2 is made effective January 1, 2014 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY INC.
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEI")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEI and FHI entered into an agreement dated as of January 1, 2010 and amended by an Amending Agreement dated January 1, 2012 (collectively, the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation at an amount, on a take-or-pay basis, to be agreed upon in writing between FEI and FHI from time to time."

3. This Amending Agreement shall be read together with the Agreement as modified.

4. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

5. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

6. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

7. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY INC.

By: ____________________

Title: President & CEO

FORTISBC HOLDINGS INC.

By: ____________________

Title: CFO & Treasurer

FortisBC Holdings Inc.
10th Floor, 1111 West Georgia
Vancouver, BC V6E 4M3
Fax: 604-443-6540
www.fortisbc.com

FORTIS BC™

January 1, 2014

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Sir/Madam:

RE: Agreement between FortisBC Holdings Inc. ("FHI") and FortisBC Energy Inc. ("FEI") dated January 1, 2010, as amended on January 1, 2012 and January 1, 2014 (the "Agreement") – Compensation for Services and Shared Costs

Pursuant to Section 3.1 of the Agreement between FHI and FEI, we propose that compensation for services and shared costs payable by FEI to FHI for the Services shall be the amount of $11,284,000 CAD. This amount shall continue to be payable under the Agreement, until such time as the Agreement is terminated or expires or the parties agree in writing to amend this amount.

Please confirm your agreement to the aforementioned compensation amount by executing the acknowledgement below. Receipt by FHI of a copy of this acknowledgement signed by FEI shall constitute the mutually agreed upon sum payable by FEI to FHI under Section 3.1 of the Agreement.

Yours truly,

FORTISBC HOLDINGS INC.

Roger Dall'Antonia
Chief Financial Officer and Treasurer

ACKNOWLEDGEMENT

FEI hereby acknowledges and agrees to the compensation amount set forth herein, for the Services provided by FHI under the Agreement.

Dated at Surrey, BC, this 6th day of June, 2013.

FORTISBC ENERGY INC.
Per:

ML
Authorized Signature

Michele Leeners
Print Name

VP Finance & CFO
Title

THIS AGREEMENT is made effective January 1, 2010.

BETWEEN:

TERASEN GAS (VANCOUVER ISLAND) INC., a corporation formed under the laws of British Columbia having an office at 16705 Fraser Highway, Surrey, British Columbia

("TGVI")

AND:

TERASEN INC., a corporation formed under the laws of British Columbia, having an office at 10th Floor, 1111 West Georgia Street, Vancouver, British Columbia

("Terasen")

WHEREAS

A. TGVI is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the communities of Vancouver Island and the Sunshine Coast; and

B. TGVI wishes to retain Terasen to provide certain professional and management services to it in respect to the ownership and operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES THAT, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1
INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international,

judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the professional and management services to be provided to TGVI by Terasen as more particularly described in Section 2.1.

1.2 Schedules

Schedule "A" is attached to, and is incorporated by reference into, this Agreement.

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,
2) any reference in this Agreement to a designated "Article", "section" or other subdivision is to the designated Article, section or other subdivision of this Agreement,
3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision,
4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,
5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and
6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

1.5 Prior Agreements

The parties agree that any prior agreements between the parties pertaining to the subject matter hereof, including the agreement effective January 1, 2004 and any amendments, are hereby cancelled and of no further effect.

PART 2

SERVICES

2.1 Services

Terasen hereby agrees to provide to TGVI those professional and management services described in Schedule "A" which Services shall include certain professional and management services provided to Terasen by its parent company, Fortis Inc. which professional and management services also benefit TGVI. .

2.2 No Obligation to Provide Additional Services

Terasen shall not perform, and Terasen shall have no obligation to perform, any services on behalf of TGVI other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGVI

Terasen will consult with TGVI as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between Terasen and TGVI. In performing the Services, Terasen shall be an independent contractor. Terasen employees shall not be considered employees of TGVI for any purpose.

2.5 Compliance

In performing the Services, Terasen will comply with all Applicable Laws.

PART 3

COMPENSATION

3.1 Compensation for Services and Shared Costs

TGVI agrees to pay to Terasen for the Services to be provided and for a proportionate share of the common expenses incurred by Terasen such as shareholder expenses and director compensation the amount of $1,622,000 per annum on a take-or-pay basis.

3.2 Amendment to Costs

The amounts set out in Section 3.1 may be amended annually by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGVI and to reflect annual inflationary adjustments. Any services to be provided that are not contemplated under this Agreement will be subject to additional compensation as agreed between the parties and form an amendment to this agreement in accordance with Section 10.3 below.

3.3 Invoicing

Terasen will invoice TGVI in respect of the Services no later than the 25th day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

TGVI will, within thirty (30) days of receipt of an invoice from Terasen, pay to Terasen the amount specified in such invoice. Any amount to be remitted by TGVI to Terasen and not remitted on or before the date on which it is due shall thereafter bear interest. A late payment charge of 1.5% per month (18% per annum) shall be payable to Terasen on any unpaid balance after thirty (30) days of the date of invoice.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4

INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGVI

Subject to Section 4.4, TGVI will indemnify, defend and hold harmless Terasen and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with Terasen's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of Terasen.

4.2 Limitation of Liability of Terasen

Neither Terasen nor any of its directors, officers, employees, agents or contractors will be liable to TGVI for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with Terasen's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of Terasen.

4.3 Indemnity by Terasen

Subject to Section 4.4, Terasen will indemnify, defend and hold harmless TGVI from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGVI may suffer or incur as a result of any act or omission or error of judgement as a result of which Terasen is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF TGVI

5.1 Covenants by TGVI

TGVI covenants and agrees to:

(a) fully co-operate with Terasen in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGVI to Terasen or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of Terasen

Terasen hereby represents and warrants to TGVI as representations and warranties which are true as at the date hereof and which will be true during the term of Terasen's appointment hereunder:

(a) Terasen is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and Terasen has full power and authority to perform its obligations hereunder;

(b) this Agreement constitutes a valid and binding obligation of Terasen enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) Terasen possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGVI

TGVI hereby represents and warrants to Terasen as representations and warranties which are true as at the date hereof and which will be true during the term of Terasen's appointment hereunder

(a) TGVI is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGVI has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGVI enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2010 and will end on December 31, 2010, unless earlier terminated pursuant to the provisions hereof. Thereafter the Agreement will automatically be renewed for further one (1) year terms subject to Section 7.2 below.

7.2 Termination

Terasen's appointment hereunder may be terminated at any time:

(a) by Terasen giving TGVI six (6) months' written notice of such termination:

(i) if TGVI becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGVI makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGVI seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGVI or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGVI consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event TGVI breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGVI of written notice thereof from Terasen or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from Terasen and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of Terasen that TGVI is in breach is conceded to be correct by TGVI or found to be correct by an arbitrator pursuant to section 8.1;

(b) by TGVI giving Terasen six (6) months' written notice of such termination:

(i) if Terasen becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if Terasen makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against Terasen seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of Terasen or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or Terasen consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event Terasen breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by Terasen of written notice thereof from TGVI or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGVI and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGVI that Terasen is in breach is conceded to be correct by Terasen or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, Terasen will have no further obligations under Article 2 and will promptly deliver to TGVI any material documents in the possession of Terasen pertaining to the business of TGVI.

7.4 Compensation of Terasen on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGVI will pay to Terasen all amounts owing to Terasen hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this section, the fees provided for in Article 3 which are payable to Terasen on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8

ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between Terasen and TGVI regarding any allegation that TGVI or Terasen is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9

FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

[Execution page follows]

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on June 24, 2009.

TERASEN GAS (VANCOUVER ISLAND) INC.

By: ______________________________
Scott A. Thomson
VP, Regulatory Affairs & CFO

Title: ______________________________

TERASEN INC.

By: ______________________________

Roger Dall'Antonia
Title: VP, Corporate Development & Treasurer

Schedule “A”

Description of Services

SERVICES PROVIDED BY TERASEN

General Governance & Oversight Services

In addition to the specific services described below, TGVI receives the benefit of the expert advice and experience of Terasen executives, who spend their time working on various committees including the Executive Committee (comprised of the CEO and senior vice presidents of Terasen as well as the heads of each operating company and the General Counsel), the Risk Management Committee and the Operating Committee.

Treasury and Cash Management

(1) Execute Financings

- a. Develop financing plans
  - i. Provide assessments of financing alternatives
  - ii. Determine timing, term, rate, structure
- b. Obtain BCUC approvals
- c. Execute financings
  - i. Negotiation, preparation of legal documentation
  - ii. Prepare disclosure documentation
  - iii. Investor presentations
  - iv. Due diligence process
  - v. Deal execution

(2) Cash Management

- a. Prepare and maintain short-term cash forecasting
- b. Execute short-term borrowing
  - i. Commercial paper issuance
  - ii. Bank borrowing
- c. Execute short-term investing of excess funds
- d. Negotiation of letters of credit
- e. Execution of manual wire transfers
- f. Establish and maintain internet based banking platform for cp issuance, fund transfers and reporting
- g. Payment of interest, principal and fees on outstanding debt

(3) Arrange operating credit facilities

a. Negotiate credit agreements

i. Determine terms and conditions

ii. Negotiate pricing and term

b. Manage syndication process

c. Obtain BCUC approval

(4) Negotiate bank-service fees

(5) Treasury-related controls and compliance

a. Develop and monitor control and compliance procedures for key Treasury procedures

(6) Compliance reporting

a. Prepare and file required compliance reports with third parties

i. Lenders, securities commissions, BCUC

(7) Hedging of interest rate and foreign exchange risks

a. Develop financial hedging plans as required

b. Negotiation of required documentation

c. Execution of derivative transaction

(8) Prepare Derivatives Policies and Procedures;

(9) Counterparty Credit Risk Management;

a. Review credit worthiness of counterparties

b. Determine appropriate credit limits for counterparties

c. Determine requirement for credit support

d. Negotiate appropriate credit support documentation

(10) Interest rate and foreign exchange rate forecasting;

(11) Regulatory submissions with respect to ROE, capital structure and financing matters;

(12) Capital structure review and maintenance; and

(13) Provide education and related materials from training courses and seminars attended by Treasury staff.

Investor Relations

(1) Manage the Rating Agency Process;

(2) Maintain investment banker and debt investor relationships;

(3) Maintain banking and money market dealer relationships;

(4) Investor and Shareholder communication;

(5) Assist in preparation of annual/quarterly disclosure documents; and

(6) Prepare annual report.

Corporate Development and Capital Management

(1) Manage the annual strategic planning cycle;

(2) Preparation and maintenance of the five year forecasting model used for strategic planning process and in the annual budgeting process;

(3) Provide financial analysis and evaluation of new projects and new initiatives;

(4) Manage the acquisition and divestiture activity;

(5) Provide project management and/or due diligence support where required; and

(6) Contract negotiation in support of business development initiatives.

External Reporting and Consolidation

(1) Consolidation and preparation of monthly financial statements for TGVI and preparation of quarterly interim reports and annual audited financial statements;

(2) Preparation of monthly reporting journal entries (consolidation, tax, accruals, etc), analytical reviews of accounts and monthly financial review package

(3) Preparation of analysis required from prospectus and other security filing documents as requested by Treasury Department and senior management;

(4) Preparation of quarterly and annual report to the Audit Committee;

(5) Compilation of information in response to a variety of enquiries from operations, senior management and external bodies, such as the BCUC, external auditors and government agencies;

(6) Research current and emerging accounting policies in Canada, the US and under International Financial Reporting ("IFRS");

(7) Direct response to accounting authorities in both Canada, the US and IFRS with respect to exposure drafts and pronouncements;

(8) Project lead for Terasen on the implementation of IFRS;

(9) Provide accounting policy advice for such issues as consistency of presentation, alternative treatments and resolution of complicated accounting policies and ensure compliance with General Accepted Accounting Principles;

(10) Accounting advice and assistance as required.

Taxation Services

(1) Prepare year-end and quarterly tax provisions including preparing tax calculations and working papers for current tax expense, providing information for the calculation of FIT expense and reviewing FIT calculations, preparing or reviewing the necessary journal entries, assisting auditors with external audit review, preparing tax disclosures to the financial statements and analyzing Balance Sheet tax accounts;

(2) Prepare tax returns and all tax compliance work for TGVI, including identification and research of technical issues, filing necessary elections, agreements and information returns, requesting post filing adjustments, and reviewing assessments and interest calculations;

(3) Calculate corporate tax instalments and arrange payment;

(4) Prepare or review tax information and calculations in support of rate cases, annual reviews and annual reports to the BCUC; participate in regulatory working groups to provide information and guidance on tax issues;

(5) Provide tax support for planning and forecasting groups; provide a strategic tax perspective into planning processes to optimize tax advantages for the Gas companies;

(6) Provide leadership, guidance and consultation to finance and operations leaders on income tax and commodity tax issues; find tax solutions to complex business issues;

(7) Monitor, identify and research tax issues resulting from tax law changes, accounting changes (such as IFRS) or business opportunities to make sound recommendations to management;

(8) Interpret impact of industry issues on tax; participate in industry group tax committees such as Canadian Gas Association and make submissions to government bodies on issues relevant to the industry;

(9) Monitor GST and PST (including Social Services Tax, Carbon Tax, ICE levy), including identifying issues and researching technical enquiries, coordinating filing of necessary elections, responding to queries on the application of GST or PST to particular transactions, training employees on the application of commodity taxes to revenues, disbursements and transactions, advising employees of commodity tax changes; advising in the implementation of new taxes;

(10) Monitor tax implications of payroll and employee benefits including advising on taxable benefits and related calculations, payroll tax issues, and pension plan tax issues;

(11) Coordinate tax audits (federal income tax, LCT, GST , various PST), provide auditors access to data, research and provide answers to auditor's requests and negotiable beneficial resolution of proposed adjustments;

(12) Prepare and file Notices of Objection and Appeal letters and coordinate legal appeals with internal and external counsel; negotiate with tax authorities with a view to minimizing ultimate liabilities;

(13) Establish and monitor tax department controls and ensure adherence to tax policies;

(14) Provide ongoing training, guidance and support to tax group employees to enhance their performance levels and career development.

Internal Audit

(1) Develop, plan and conduct audits/reviews of areas or processes of particular interest or of identified risk and prepare internal audit reports;

(2) Conduct annual risks assessment process in conjunction with the Enterprise Risk Management group;

(3) Monitor and evaluate the effectiveness and efficiency of controls throughout the year and summarize results to the Audit Committee of the Board of Directors;

(4) Ensure that the TGVI Code of Business Conduct compliance management is effective by conducting the annual compliance reviews and acting as a resource when issues arise with respect to the Code of Business Conduct;

(5) Monitor the Whistle Blower Ethics line and address issues as they arise;

(6) Participate on various committees in the capacity of ex-officio to provide oversight and value add;

(7) Undertake work at the request of the BC Utilities Commission regarding the activities and operations of TGVI.

(8) Provide annual reports summarizing Internal Audit activities and findings to the BCUC as well as other reports of regulatory compliance;

(9) Conduct post implementation reviews of major capital projects and acquisitions and report results to the Audit Committee;

(10) Provide assistance to the external auditors in completing their external financial audits; and

(11) Coordinate activities of various internal and external assurance providers to ensure proper coverage and minimize duplication of efforts.

Risk Management and Insurance Services

(1) Ensure compliance with the TSX requirements on risk management by ensuring that the Board of Directors understand the principal risks of all aspects of business that TGVI is engaged in, and ensuring that there are systems in place that effectively manage and monitor those risks with a view to the long term viability of the TGVI;

(2) Arrange for coverage based on assessed potential risk of damage or loss in asset values, disruptions in operations or potential legal liabilities;

(3) Advise dollar value of coverage required, most appropriate coverage and proper services required;

(4) Provide a single insurance program to achieve economies of scales and cost reductions;

(5) Work with broker in negotiating renewals and adequacy of coverage;

(6) Ensure competitive terms and consider all available options;

(7) Establish procedures and provide assistance and guidance in the reporting, handling, compiling, negotiating and settlement of claims;

(8) Provide mechanism for appropriate and timely local resolution of third party damage claims below a given threshold and payment of same;

(9) Conduct of review of contractual agreements to protect TGVI from unnecessary assumption of risks;

(10) Coordinate Risk Management's group participating in industry associations and education seminars;

(11) Establish loss control standards to help ensure consistent and high degree of loss; prevention in all operating units and minimize impact when they do occur;

(12) Ensure familiarity with policies and wordings;

(13) Encourage and establish procedures for loss control;

(14) Administer Certificates of Insurance;

(15) Preparation of management reports;

(16) Provide additional insurance for individual construction projects, as required; and

(17) Provide bonding as required.

Corporate Secretary's Office

(1) Ensure all continuous disclosure and governance activities required by external regulators and third parties are appropriately carried out, including Securities filings and BC Business Corporations Act requirements; and

(2) Manage the relationship and corporate activities of the Board of Directors.

(3) Prepare materials for Board of Directors and minutes.

(4) Track and maintain corporate records.

(5) Assist in preparation of corporate documentation and providing corporate information to internal and external parties.

Legal Department

(1) Provide all legal services to TGVI other than those outsourced to outside legal counsel;

(2) Direct the provision and management of outside legal services, primarily litigation, to TGVI;

(3) Provide management of all litigation;

(4) Provide legal counsel on regulatory, environmental, marketing, employment, and intellectual property;

(5) Ensure legal compliance for press release, financial reports and other disclosure documents;

(6) Advise TGVI on legal issues that may arise including claims, actions, real estate and other property transactions, and contracts, including the purchase of goods and services by TGVI; and

(7) Provide general miscellaneous legal support and advice to management.

Human Resources Compensation and Planning

(1) Consult with management on the maintenance, development and governance of employees and retiree benefit programs, pension plans, employee savings plans and employee assistance programs;

(2) Provide assistance on annual wage and salary increases, providing labour market comparisons, establishing and implementing ad hoc increases for long term disability and pension recipients;

(3) Ensure that employment practices are in compliance with applicable regulations and legislation through development and administration of appropriate corporate policies and procedures;

(4) Consulting and direction on disability management guidelines and policy;

(5) Oversee the annual preparation of the executive succession plan and present the plan to the Management Resources Committee and to the Board of Directors;

(6) Corporate governance and direction regarding benefits carriers, benefits and pension consultants, financial services providers;

(7) Corporate reporting to legislative bodies, CCRA, Statistics Canada, Pension Standards, as required; and

(8) Corporate governance of salary and benefit administration, including executive and management compensation.

SERVICES PROVIDED BY FORTIS INC. ("FORTIS")

Executive Function

President & CEO

A. Strategic Direction

1. Present annually to the Board of Directors of Fortis (the "Board") a strategic plan and a business plan which must (a) be designed to achieve the corporate objectives together with an appropriate set of performance measures, (b) identify the principal strategic and operational risks of the business, and (c) include appropriate methods to manage the risks;
2. Obtain Board approval for the strategic plan and the business plans of Fortis as a precondition to the implementation of such plans;
3. Obtain Board approval for the procurement, allocation, and disposition of corporate resources for Fortis as a precondition to such procurement, allocation or disposition of such resources either;
   a. in the approved Business Plan; or
   b. by specific authorization of an asset transaction consistent with current business activities in an amount in excess of $XX [insert amount] million ($XX [insert amount] million annual aggregate) and for any share transaction (other than increased investment in an existing affiliate within the transaction size parameters noted above); and
4. Communicate the principal objectives and strategic plan for Fortis throughout Fortis.

B. Leadership and Management of Fortis

1. Lead Fortis with vision and values that are well understood, widely supported and consistently followed;
2. Foster a corporate culture which promotes ethical practices, personal integrity and the fulfilment of social responsibilities;
3. Create the appropriate environment to stimulate employee morale and productivity;
4. Manage change proactively;
5. Ensure continuous improvement in the quality and value of the products and services provided by Fortis;
6. Ensure that Fortis achieves and maintains satisfactory competitive positions within its industries; and
7. Serve as a director of Fortis.

C. *Management and Organization Structure*

1. Provide advice to the Board on the appointment of all officers of Fortis;
2. Assist the Board in establishing the limits of delegated authority and responsibility in conducting Fortis's business;
3. Provide annually to the Board, an evaluation of the performance of each senior manager who reports to the CEO;
4. Present for approval to the Board, an annual plan which will provide for the development and succession of senior managers of Fortis in a timely fashion;
5. Generally develop, attract, and retain a highly motivated, effective management team; and
6. Obtain Board approval for any proposed significant or material change in the organizational structure of Fortis as a precondition to the implementation of such changes.

D. *Finances, Controls and Internal Systems*

1. Consistently strive to achieve Fortis's annual and long-term financial goals and objectives;
2. Assist the Board in establishing an appropriate capital structure for Fortis;
3. Ensure that Fortis has systems in place to effectively monitor and manage the principal risks related to the operation of the business(es);
4. Establish and maintain the integrity of Fortis's financial controls and reporting systems and compliance of the financial information with appropriate accounting principles;
5. Establish and monitor processes and systems designed to ensure compliance with all applicable laws by Fortis, its officers and employees; and
6. Provide certification of financial matters, including the completeness and accuracy of Fortis's financial statements and, where necessary, matters relating to internal controls over financial reporting.

E. *Employee Relations*

1. Ensure that a process is in place to monitor compliance with the ethical standards to be observed by all officers and employees of Fortis, and ensure that a process is in place to monitor divergence from the ethical standards to be observed by all employees; and
2. Establish and maintain effective communications with employees of Fortis.

F. *External Communication*

1. Assist the Board in establishing and maintaining an effective communications policy with shareholders, the financial community, the media, the community at large and other stakeholders;
2. Ensure that Fortis contributes, and is perceived to contribute, to the well-being of the communities it serves; and
3. Serve as the principal representative and spokesperson of Fortis.

G. *Board Relations*

1. Keep the Board adequately informed, on a timely basis, with respect to all events and information which the CEO believes might materially affect Fortis, its performance, prospects, and image;
2. Provide the assistance necessary for the Chair of the Board and committees of the Board to carry out their duties;
3. Be entitled to attend all meetings of Board committees and provide Board committees the assistance necessary to carry out their mandates;
4. Assist the Board in reviewing and maintaining an up-to-date position description for the President and CEO of Fortis; and
5. Report to the Board on material use of outside consultants.

VP Finance and CFO

1. Advise and assist the Chairman of the Board and President and CEO in the development of strategies and goals in the financial planning and structure of the Group and in the control of the Company's business operations.
2. Keep the CEO informed of all relevant financial information and report on the financial status and performance of all companies in the group to the Board of Directors of Fortis Inc.
3. Responsible for all aspects of investor relations program, including shareholder communications and shareholder meetings.
4. Liaison with the investment community and market surveillance.
5. Ensure that procedures and systems necessary to maintain proper records and to afford adequate accounting controls and services are implemented throughout the organization.
6. Ensure that uniform financial policies and procedures are adhered to throughout the organization.
7. Ensure the development and maintenance of timely financial information systems.
8. Develop and maintain effective internal and external audit activities and recommend proper financial controls.

9. Develop and maintain suitable budgeting procedures and reviews.
10. Direct the planning and control of corporate cash requirements and major banking relationships.
11. Review capital expenditure plans and budgeting.
12. Plan and direct corporate financing.
13. Recommend guidelines for financial transactions between companies in the Fortis Group.
14. Ensure that adequate financial personnel resources are retained and appropriately assigned throughout the group.
15. Appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions. As demanded, manage external financial consulting resources.
16. Maintain an awareness of changes in practice and procedure within the professional accounting field.
17. Act as CFO of subsidiary organizations when required.

General Counsel & Corporate Secretary

1. Prepare schedules, notices, agendas, resolutions, and minutes for the Boards of Directors of Fortis Inc. and selected subsidiaries and affiliates.
2. Coordination of all communications to Board of Directors.
3. Operation of share purchase plans.
4. Preparation of security documents including Management Information Circulars, Annual Information Forms and prospectuses.
5. Responsible for regulatory compliance, including annual returns to the registries of companies, dividend disclosure, filing of annual and quarterly reports, reports to stock exchanges, notices of Material Change, and Insider Reports.
6. Provide legal services to all corporations in the Fortis Group including, when necessary, engagement of outside legal services.

Treasury and Taxation Function

1. Manage equity financing, including both common and preference shares, and related prospectuses
2. Manage debt financing, including long-term debt and credit facility borrowings as well as borrowing rates
3. Maintaining the capital structure

4. Assist the VP finance and CFO appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions
5. Cash management and forecasting activities – including dividend and interest payments and equity injections required by subsidiaries
6. Managing cash requirements of subsidiaries, as required, as it relates to intercompany loans and required equity injections
7. Debt covenant calculations and monitoring
8. Managing hedging activities related to US dollar debt
9. Preparation of annual corporate tax returns and related foreign affiliate corporate tax returns
10. Calculation of quarterly and annual Fortis Inc. corporate tax provision
11. Responsibility for utilization of non-capital and capital loss carryforwards of Fortis Inc. and coordination of tax utilization plans with applicable subsidiaries
12. Managing corporate reorganizations and tax planning
13. Manage tax implications of payroll and employee benefits including researching and advising on taxable benefits, CPP, EI and payroll tax issues
14. Preparing Fortis Inc. employee T4's, including preparing taxable benefit calculations
15. Coordination of Fortis Inc. corporate income tax or HST audits
16. Tax research associated with tax issues and changes in tax laws

<u>Investor Relations Function</u>

1. Manage analyst communications – including review of analysts' commentaries/research reports, conduct quarterly conference calls and respond to general analyst research inquiries.
2. Manage investor communications – including the preparation and delivery of investor presentations, road shows, web casts, teleconferences and one-on-one meetings with existing and prospective shareholders
3. Manage shareholder communications – including responding to general shareholder inquiries and the preparation, delivery and filing of documentation for quarterly and annual mailings (i.e., quarterly reports, annual report, proxy, management information circular and annual information form).
4. Coordination and preparation of Fortis's Annual Meeting including preparation of the Executive's presentation to shareholders.
5. Coordination of solicitation of proxies.
6. Preparation of Quarterly Investor Relations Reports to the Board of Directors.

7. Preparation, coordination and dissemination of media releases to newswire agencies, websites and distribution lists.
8. Monitor and maintain Fortis's media coverage.
9. Develop, host and maintain the Fortis Inc. website.
10. Monitor the websites of the Fortis Group of Companies.
11. Monitor and research the market and investment community through Bloomberg, ThomsonOne, TSX, etc.
12. Manage and maintain the Fortis Inc. dividend reinvestment and share purchase plans (i.e., Dividend Reinvestment and Share Purchase Plan, Consumer Share Purchase Plan and Employee Share Purchase Plan)
13. Coordination and preparation of Fortis's consolidated Strategic Issues document and presentation to the Board of Directors.
14. Preparation of Fortis's consolidated Business Plan presentation to the Board of Directors.
15. Manage public relations – including conference participation, the preparation of Executive speeches and responding to media inquiries.

Financial Reporting Function

1. Preparation of quarterly and annual consolidated financial statements and notes to the financial statements and the related management discussion and analysis
2. Preparation of monthly internal consolidated and non-consolidated financial statements of Fortis Inc.
3. Coordination with external auditors of the annual audit of the consolidated financial statements and quarterly review of consolidated financial statements.
4. Preparation and analysis of financial information required for prospectus and other security filing documents
5. Preparation of the Annual Information Form and providing assistance in the preparation of the Management Information Circular
6. Assisting in responding to reviews and queries of securities regulators related to continuous disclosure reporting
7. Research current and emerging accounting policies in Canada, US and that related to IFRS
8. Coordinate consistent accounting policy treatment across the Fortis group of companies related to presentation, alternative treatments and resolution of complex accounting policies to ensure compliance with GAAP

9. Oversight and coordination of conversion to International Financial Reporting Standards across the Fortis Group of companies – including coordinating research, organizing working group and steering committee sessions to discuss and resolve ongoing issues and progress, monitoring and directing progress of the overall conversion and coordination with the external auditors
10. Coordination and preparation of consolidated Business Plan document and reporting to the Board of Directors
11. Preparation of quarterly forecasted consolidated earnings and EPS
12. Responsibility for maintaining internal controls over financial reporting at Fortis Inc.

Internal Audit Function

1. Performs internal audit activities at Fortis Inc including:
    a. coordinating the Fortis Inc. CEO and CFO internal controls certification process through maintenance of financial process documentation and annual evaluation of internal controls over financial reporting and disclosure controls. Involves ensuring that all Fortis subsidiaries are fully compliant in order to support certification by the parent company;
    b. performing quality assurance reviews of Fortis Inc. continuous disclosures documents prior to public filing;
    c. performing annual reviews of Fortis Inc. statutory obligations and executive expenditures;
    d. reporting internal audit activities to the Fortis Inc. Audit Committee on a regular basis; and
    e. coordinating compliance with corporate governance requirements

2. Provides oversight over the internal audit function at the Fortis subsidiary companies to:
    a. ensure corporate-wide consistency in the application of internal audit methodologies and practices and in the reporting of audit results to management and audit committees;
    b. coordinate annual audit program planning to ensure critical risk areas are addressed;
    c. coordinate corporate-wide audit projects;
    d. identify opportunities for audit resource and information sharing between the subsidiary internal audit groups;

e. oversees audit program planning and reviews internal audit reports to management and Audit Committees for these subsidiaries with limited internal audit resources;

3. Administers and monitors reports of allegations of suspected improper conduct or wrong doing via Fortis's ethics reporting system
4. Development of a company-wide Enterprise Risk Management program approach

Board of Directors

The Board of Directors of Fortis Inc. is responsible for the stewardship of Fortis. The Board will supervise the management of the business and affairs of Fortis and, in particular, will:

A. Strategic Planning and Risk Management

1. Adopt a strategic planning process and approve, on an annual basis, a strategic plan for Fortis which considers, among other things, the opportunities and risks of the business;
2. Monitor the implementation and effectiveness of the approved strategic and business plan;
3. Assist the CEO in identifying the principal risks of Fortis's business and the implementation of appropriate systems to manage such risks;

B. Management and Human Resources

1. Select, appoint and evaluate the CEO, and determine the terms of the CEO's employment with Fortis;
2. In consultation with the CEO, appoint all officers of Fortis and determine the terms of employment, training, development and succession of senior management (including the processes for appointing, training and evaluating senior management);
3. To the extent feasible, satisfy itself as to the integrity of the CEO and other officers and the creation of a culture of integrity throughout Fortis;

C. Finances, Controls and Internal Systems

1. Review and approve all material transactions including acquisitions, divestitures, dividends, capital allocations, expenditures and other transactions which exceed threshold amounts set by the Board (including equity contributions to subsidiaries to support the investment in rate base to serve customers;
2. Evaluate Fortis's internal controls relating to financial and management information systems;

D. *Communications*

1. Adopt a communication policy that seeks to ensure that effective communications, including statutory communication and disclosure, are established and maintained with employees, shareholders, the financial community, the media, the community at large and other security holders of Fortis;
2. Establish procedures to receive feedback from stakeholders of Fortis and communications to the independent directors as a group;

E. *Governance*

1. Develop Fortis's approach to corporate governance issues, principles practices and disclosure;
2. Establish appropriate procedures to evaluate director independence standards and allow the Board to function independently of management;
3. Appoint from among the directors an audit committee and such other committees of the Board as deemed appropriate and delegate responsibilities thereto in accordance with their mandates;
4. Develop and monitor policies governing the operation of subsidiaries through exercise of Fortis's shareholder positions in such subsidiaries;
5. Develop and monitor compliance with Fortis's code of conduct;
6. Set expectations and responsibilities of directors, including attendance at, preparation for and participation in meetings; and
7. Evaluate and review the performance of the Board, each of its committees and its members.

THIS AMENDING AGREEMENT is made effective January 1, 2012 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
(formerly Terasen Gas (Vancouver Island) Inc.)
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEVI")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
(formerly Terasen Inc.)
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEVI and FHI entered into an agreement dated as of January 1, 2010 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. All references to "Terasen Gas (Vancouver Island) Inc." and "TGVI" shall be deleted and replaced with "FortisBC Energy (Vancouver Island) Inc." and "FEVI" respectively.

3. All references to "Terasen Inc." and "Terasen" shall be deleted and replaced with "FortisBC Holdings Inc." and "FHI" respectively.

4. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEVI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $1,140,100 per annum for the period of January 1, 2012 to December 31, 2012 on a take-or-pay basis and the amount of $1,196,300 per annum for the period of January 1, 2013 to December 31, 2013 on a take-or-pay basis."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

7. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

8. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

9. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

By: ____________________
Roger Dall'Antonia

Title: Vice President, Finance + CFO

FORTISBC HOLDINGS INC.

By: ____________________
Scott Thomson

Title: Executive Vice President, Finance, Regulatory & Energy Supply

THIS AMENDING AGREEMENT #2 is made effective January 1, 2014 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEVI")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEVI and FHI entered into an agreement dated as of January 1, 2010 and amended by an Amending Agreement dated January 1, 2012 (collectively, the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEVI agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation at an amount, on a take-or-pay basis, to be agreed upon in writing between FEVI and FHI from time to time."

3. This Amending Agreement shall be read together with the Agreement as modified.

4. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

5. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

6. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

7. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.

By: ______________________

Title: President & CEO

FORTISBC HOLDINGS INC.

By: ______________________

Title: CFO & Treasurer

FORTIS BC™

FortisBC Holdings Inc.
10th Floor, 1111 West Georgia
Vancouver, BC V6E 4M3
Fax: 604-443-6540
www.fortisbc.com

January 1, 2014

FortisBC Energy (Vancouver Island) Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Sir/Madam:

RE: Agreement between FortisBC Holdings Inc. ("FHI") and FortisBC Energy (Vancouver Island) Inc. ("FEVI") dated January 1, 2010, as amended on January 1, 2012 and January 1, 2014 (the "Agreement") – Compensation for Services and Shared Costs

Pursuant to Section 3.1 of the Agreement between FHI and FEVI, we propose that compensation for services and shared costs payable by FEVI to FHI for the Services shall be the amount of $1,223,000 CAD. This amount shall continue to be payable under the Agreement, until such time as the Agreement is terminated or expires or the parties agree in writing to amend this amount.

Please confirm your agreement to the aforementioned compensation amount by executing the acknowledgement below. Receipt by FHI of a copy of this acknowledgement signed by FEVI shall constitute the mutually agreed upon sum payable by FEVI to FHI under Section 3.1 of the Agreement.

Yours truly,

FORTISBC HOLDINGS INC.

Roger Dall'Antonia
Chief Financial Officer and Treasurer

ACKNOWLEDGEMENT

FEVI hereby acknowledges and agrees to the compensation amount set forth herein, for the Services provided by FHI under the Agreement.

Dated at Surrey, BC, this 6th day of June, 2013.

FORTISBC ENERGY (VANCOUVER ISLAND) INC.
Per:

Authorized Signature

Michele Leeners
Print Name

VP Finance & CFO
Title

THIS AGREEMENT is made effective January 1, 2010.

BETWEEN:

TERASEN GAS (WHISTLER) INC. a corporation formed under the laws of British Columbia, having an office at 16705 Fraser Highway, Surrey, British Columbia

("TGW")

AND:

TERASEN INC., a corporation formed under the laws of British Columbia, having an office at 10th Floor, 1111 West Georgia Street, Vancouver, British Columbia

("Terasen")

WHEREAS

A. TGW is the owner and operator of the natural gas transmission and distribution facilities in British Columbia serving the community of Whistler; and

B. TGW wishes to retain Terasen to provide certain professional and management services to it in respect to the ownership and operations of its transmission pipeline and distribution business on the terms and conditions set out herein.

WITNESSES THAT, in consideration of the covenants and agreements herein contained, the parties covenant and agree as follows:

PART 1

INTERPRETATION

1.1 Definitions

In and for the purpose of this Agreement

(a) "**Applicable Laws**" means any and all Laws in force and effect from time to time and applicable to the Facilities and the performance of the Services hereunder;

(b) "**Force Majeure**" has the meaning assigned to such term in Section 9.1;

(c) "**Governmental Authority**" means any domestic or foreign, national, federal, provincial, state, municipal or other local government or body and any division, agent, commission, board, or authority of any quasi-governmental or private body exercising any statutory, regulatory, expropriation or taxing authority under the authority of any of the foregoing, and any domestic, foreign, international, judicial, quasi-judicial, arbitration or administrative court, tribunal, commission, board or panel acting under the authority of any of the foregoing;

(d) "**Laws**" means all constitutions, treaties, laws, statutes, codes, ordinances, orders, decrees, rules, regulations and municipal by-laws, whether domestic, foreign or international, any judgements, orders, writs, injunctions, decision, rulings, decrees, and awards of any Governmental Authority, and any published policies or guidelines of any Governmental Authority and including, without limitation, any principles of common law and equity,

(e) "**Person**" includes any individual, corporation, body corporate, partnership, joint venture, association, trust, estate, incorporated or unincorporated association, any government or governmental authority however designated or constituted or any other entity of whatever nature,

(f) "**Services**" means the professional and management services to be provided to TGW by Terasen as more particularly described in Section 2.1.

1.2 Schedules

Schedule "A" is attached to, and is incorporated by reference into, this Agreement.

1.3 Interpretation

In and for the purpose of this Agreement

1) this "Agreement" means this agreement as the same may from time to time be modified, supplemented or amended in effect,
2) any reference in this Agreement to a designated "Article", "section" or other subdivision is to the designated Article, section or other subdivision of this Agreement,
3) the words "herein", "hereof" and "hereunder" and other words of similar import refer to this Agreement as a whole and not to any particular Article, section or other subdivision,
4) the headings are for convenience only and do not form a part of this Agreement and are not intended to interpret, define or limit the scope, extent or intent of this Agreement,
5) the singular of any term includes the plural, and vice versa, the use of any term is generally applicable to any gender and, where applicable, a corporation, the word "or" is not exclusive and the word "including" is not limiting (whether or not non-limiting language (such as "without limitation" or "but not limited to" or words of similar import) is used with reference thereto), and
6) each word and phrase used herein and not otherwise defined herein, but which has an accepted meaning in the custom and usage of the Western Canadian oil and gas transportation industry, shall have such accepted meaning.

1.4 Governing Law

Subject to Section 9.1, this Agreement will be interpreted and the rights and remedies of the parties hereto will be determined in accordance with the laws of the Province of British Columbia.

PART 2
SERVICES

2.1 Services

Terasen hereby agrees to provide to TGW those professional and management services described in Schedule "A" which Services shall include certain professional and management services provided to Terasen by its parent company, Fortis Inc. which professional and management services also benefit TGW. .

2.2 No Obligation to Provide Additional Services

Terasen shall not perform, and Terasen shall have no obligation to perform, any services on behalf of TGW other than as set out in this Agreement or any similar agreement.

2.3 Consultation with TGW

Terasen will consult with TGW as required in connection with the performance of the Services.

2.4 Independent Contractor

Nothing in this Agreement shall be construed to create or constitute a partnership or relationship of joint venture between Terasen and TGW. In performing the Services, Terasen shall be an independent contractor. Terasen employees shall not be considered employees of TGW for any purpose.

2.5 Compliance

In performing the Services, Terasen will comply with all Applicable Laws.

PART 3
COMPENSATION

3.1 Compensation for Services and Shared Costs

TGW agrees to pay to Terasen for the Services to be provided and for a proportionate share of the common expenses incurred by Terasen such as shareholder expenses and director compensation the amount of $48,000 per annum on a take-or-pay basis.

3.2 Amendment to Costs

The amounts set out in Section 3.1 may be amended annually by agreement between the parties to reflect any material change in the cost of providing the services or in the business operations of TGW and to reflect annual inflationary adjustments. Any services to be provided that are not contemplated under this Agreement will be subject to additional compensation as agreed between the parties and form an amendment to this agreement in accordance with Section 10.3 below.

3.3 Invoicing

Terasen will invoice TGW in respect of the Services no later than the 25^{th} day following the end of the month in which such Services are provided or in such other manner as the parties may agree.

3.4 Payment

TGW will, within thirty (30) days of receipt of an invoice from Terasen, pay to Terasen the amount specified in such invoice. Any amount to be remitted by TGW to Terasen and not remitted on or before the date on which it is due shall thereafter bear interest. A late payment charge of 1.5% per month (18% per annum) shall be payable to Terasen on any unpaid balance after thirty (30) days of the date of invoice.

3.5 Taxes

Notwithstanding any other provision of this Agreement, the amounts paid or payable by one party to the other in accordance with this Agreement are exclusive of any value added taxes or sales taxes, which are now, or may become during the term of this Agreement, applicable to the provision of the Services. Each party shall pay to the other party any value added taxes or sales tax which one party is obligated to collect from the other at the time such taxes are due and payable.

PART 4
INDEMNIFICATION AND LIMITATION OF LIABILITY

4.1 Indemnity by TGW

Subject to Section 4.4, TGW will indemnify, defend and hold harmless Terasen and its directors, officers, employees, agents and contractors, from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, and cost or expense (including reasonable legal fees and disbursements) which they may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with Terasen's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of Terasen.

4.2 Limitation of Liability of Terasen

Neither Terasen nor any of its directors, officers, employees, agents or contractors will be liable to TGW for any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award, or cost or expense (including reasonable legal fees and disbursements) which TGW may suffer or incur arising directly or indirectly, in whole or in part, in connection with this Agreement or with Terasen's provision of the Services, except and to the extent, if any, that the same results from or arises out of the wilful misconduct or gross negligence of Terasen.

4.3 Indemnity by Terasen

Subject to Section 4.4, Terasen will indemnify, defend and hold harmless TGW from and against any claim, demand, loss, liability, action, lawsuit or other proceeding, judgement or award and cost or expense (including reasonable legal fees and disbursements) which TGW may suffer or incur as a result of any act or omission or error of judgement as a result of which Terasen is adjudged to have been guilty of wilful misconduct or gross negligence.

4.4 Consequential Losses

Neither party hereto will be liable to the other, whether based in contract, tort (including negligence and strict liability), under warranty or otherwise for special indirect, incidental or consequential loss or damage whatsoever, including without limitation, loss of use of equipment or facilities and loss of profits or revenues.

PART 5

COVENANTS OF TGW

5.1 Covenants by TGW

TGW covenants and agrees to:

(a) fully co-operate with Terasen in respect of all matters contemplated by or within the scope of this Agreement; and

(b) pay on or before the due date thereof all amounts payable by TGW to Terasen or any other Person pursuant to or as contemplated by this Agreement.

PART 6

REPRESENTATIONS AND WARRANTIES

6.1 Representations and Warranties of Terasen

Terasen hereby represents and warrants to TGW as representations and warranties which are true as at the date hereof and which will be true during the term of Terasen's appointment hereunder:

(a) Terasen is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and Terasen has full power and authority to perform its obligations hereunder;

(b) this Agreement constitutes a valid and binding obligation of Terasen enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought; and

(c) Terasen possesses all of the skills and personnel required to provide the Services.

6.2 Representations and Warranties of TGW

TGW hereby represents and warrants to Terasen as representations and warranties which are true as at the date hereof and which will be true during the term of Terasen's appointment hereunder

(a) TGW is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and TGW has full power and authority to perform its obligations hereunder; and

(b) this Agreement constitutes a valid and binding obligation of TGW enforceable in accordance with its terms, except that (i) such enforcement may be subject to bankruptcy, insolvency, reorganization, moratorium or other similar laws now or hereafter in effect relating to creditors' rights, and (ii) the remedy of specific performance and injunctive or other forms of equitable relief may be subject to equitable defences and to the discretion of the court before which any proceeding therefore may be brought.

PART 7

DURATION, TERMINATION AND DEFAULT

7.1 Effective Date and Term

This Agreement will be effective from January 1, 2010 and will end on December 31, 2010, unless earlier terminated pursuant to the provisions hereof. Thereafter the Agreement will automatically be renewed for further one (1) year terms subject to Section 7.2 below.

7.2 Termination

Terasen's appointment hereunder may be terminated at any time:

(a) by Terasen giving TGW six (6) months' written notice of such termination:

(i) if TGW becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if TGW makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against TGW seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of TGW or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or TGW consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event TGW breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by TGW of written notice thereof from

Terasen or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from Terasen and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of Terasen that TGW is in breach is conceded to be correct by TGW or found to be correct by an arbitrator pursuant to section 8.1;

(b) by TGW giving Terasen six (6) months' written notice of such termination:

(i) if Terasen becomes insolvent, admits in writing its inability to pay its debts as they become due or commits or threatens to commit an act of bankruptcy or if Terasen makes a general assignment for the benefit of creditors, or any proceeding is instituted by or against Terasen seeking to adjudicate it a bankrupt or an insolvent or seeking the dissolution, winding-up or liquidation of Terasen or a reorganization, arrangement, moratorium, adjustment, compromise, readjustment of debt or composition of it or its debts under any law relating to bankruptcy, insolvency, moratorium, reorganization or relief of debtors or seeking the appointment of a receiver, receiver-manager, interim receiver, trustee, custodian, liquidator or other similar official or Person for it, or Terasen consents by answer, acquiescence or otherwise to the institution of any such proceeding against it; or

(ii) in the event Terasen breaches this Agreement and fails to cure such breach within thirty (30) days after receipt by Terasen of written notice thereof from TGW or, if such breach is not capable of being cured within such thirty (30) day period, fails to commence in good faith the curing of such breach forthwith upon receipt of written notice thereof from TGW and to continue to diligently pursue the curing of such breach thereafter until cured and, in either case, the allegation of TGW that Terasen is in breach is conceded to be correct by Terasen or found to be correct by an arbitrator pursuant to Section 8.1.

7.3 Duties Upon Termination

Upon expiry or termination of this Agreement for any reason, Terasen will have no further obligations under Article 2 and will promptly deliver to TGW any material documents in the possession of Terasen pertaining to the business of TGW.

7.4 Compensation of Terasen on Expiry or Termination

Within one (1) month after the expiry or termination of this Agreement, TGW will pay to Terasen all amounts owing to Terasen hereunder (including any amount owing on account of the fees provided for in Article 3 calculated up to the date of expiry or termination); provided that for the purposes of this section, the fees provided for in Article 3 which are payable to Terasen on a monthly, annual or other periodic basis will be deemed to accrue due and be payable on a daily basis.

PART 8
ARBITRATION

8.1 Arbitration

For purposes of Section 7.2, any dispute between Terasen and TGW regarding any allegation that TGW or Terasen is in breach of this Agreement, may be submitted to and settled by arbitration in accordance with the provisions of this Section 8.1. Arbitration proceedings may be commenced by the party desiring arbitration giving notice to the other party specifying the matter to be arbitrated and requesting arbitration thereof. Such arbitration will be carried out by a single arbitrator and in accordance with the National Arbitration Rules of the ADR Institute of Canada Inc. for Dispute Resolution from time to time in force and effect. If the parties are unable to agree upon an arbitrator within ten (10) days after delivery of such notice, either of them may make application to court for appointment of an arbitrator. In the event of the failure, refusal or inability of an arbitrator to act, or continue to act, a new arbitrator will be appointed, which appointment will be made in the same manner as provided above. The decision of an arbitrator appointed as under this Section 8.1 will be final and binding upon the parties and not subject to appeal. The arbitrator will have the authority to assess the costs of the arbitration against either or both of the parties, provided that each party will bear its own witness and counsel fees. The parties will fully co-operate with the arbitrator and provide all information reasonably requested by the arbitrator. Judgement on the award of the arbitrator may be entered in any court having jurisdiction over the party against which enforcement of the award is being sought. Each party hereby irrevocably submits and consents to the jurisdiction of any such court for the purpose of rendering a judgement of any such award.

PART 9
FORCE MAJEURE

9.1 Force Majeure

In and for the purposes of this Agreement, "Force Majeure" shall mean anyone or more of the following events:

(a) an act of God;

(b) a war, revolution, insurrection, riot, blockade, or any other unlawful act against public order or authority;

(c) a strike, lockout or other industrial disturbance;

(d) a storm, fire, flood, explosion, earthquake or lightning;

(e) a governmental restraint; or

(f) any other event (whether or not of the kind enumerated in 9.1(a) to (e) above) which is not reasonably within the control of the party hereto claiming suspension of its obligations hereunder due to Force Majeure.

9.2 Performance Prevented by Force Majeure

If either party hereto is prevented by Force Majeure from carrying out any of its obligations hereunder, the obligations of such party, insofar as its obligations are affected by Force Majeure, shall be suspended while (but only so long as) Force Majeure continues to prevent the performance of such obligations. Any party prevented from carrying out any obligation by Force Majeure shall promptly give the other party hereto notice of Force Majeure including reasonably full particulars thereof.

9.3 Remedy of Force Majeure

A party claiming suspension of its obligations by reason of Force Majeure shall promptly remedy the cause and effect of Force Majeure described in the notice given pursuant to Section 9.2 insofar as such party is reasonably able so to do, provided that the terms of settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of the party hereby claiming suspension of its obligations hereunder by reason thereof; and that such party shall not be required to accede to the demands of its opponents in any strike, lockout or industrial disturbance solely to remedy promptly Force Majeure thereby constituted.

9.4 Lack of Funds Not Force Majeure

Notwithstanding anything contained in this Article 9, lack of finances shall not be considered Force Majeure nor shall Force Majeure suspend any obligation for the payment of money due hereunder.

PART 10

MISCELLANEOUS

10.1 Notice

Any notice, direction or other communication required or permitted to be given hereunder must be in writing and will be sufficiently given if delivered or sent by facsimile to the party from whom it is intended at the address of such party set out below. Any notice, direction or other communication so given will be deemed to have been given and to have been received on the day of delivery, if delivered, or on the day of sending if sent by facsimile (provided such day of delivery or sending is a Business Day and, if not, then on the first Business Day thereafter). Each party hereto may change its address for notice by notice given in the manner aforesaid.

10.2 Assignment

Neither party hereto may assign this Agreement or any of its rights hereunder without the prior written consent of the other party, such consent not to be unreasonably withheld.

10.3 Amendments

Any amendment or modification of this Agreement must be in writing and signed by the party against which such amendment or modification is sought to be enforced.

10.4 Severability

If any term or condition of this Agreement or the application hereof is determined judicially or otherwise to be invalid or unenforceable, the remainder of this Agreement and the application thereof shall not be affected and shall remain in full force and effect.

10.5 Entire Agreement

This Agreement constitutes the entire agreement between the parties pertaining to the subject matter hereof. There are no representations, warranties, covenants or agreements between the parties in connection with such subject matter except as specifically set forth or referred to in this Agreement.

10.6 Counterparts, Facsimile

This Agreement may be executed by the execution of one or more counterparts of the execution page, which will be taken together and constitute the execution page, and one or more of such counterparts may be delivered by facsimile transmission.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement on October 14, 2009.

TERASEN GAS (WHISTLER) INC.

By: ______________________

Title: Scott A. Thomson
VP, Regulatory Affairs & CFO

TERASEN INC.

By: ______________________

R.L. (Randy) Jespersen
Title: President & CEO

Schedule "A"

Description of Services

SERVICES PROVIDED BY TERASEN

General Governance & Oversight Services

In addition to the specific services described below, TGW receives the benefit of the expert advice and experience of Terasen executives, who spend their time working on various committees including the Executive Committee (comprised of the CEO and senior vice presidents of Terasen as well as the heads of each operating company and the General Counsel), the Risk Management Committee and the Operating Committee.

Treasury and Cash Management

(1) Execute Financings
- a. Develop financing plans
  - i. Provide assessments of financing alternatives
  - ii. Determine timing, term, rate, structure
- b. Obtain BCUC approvals
- c. Execute financings
  - i. Negotiation, preparation of legal documentation
  - ii. Prepare disclosure documentation
  - iii. Investor presentations
  - iv. Due diligence process
  - v. Deal execution

(2) Cash Management
- a. Prepare and maintain short-term cash forecasting
- b. Execute short-term borrowing
  - i. Commercial paper issuance
  - ii. Bank borrowing
- c. Execute short-term investing of excess funds
- d. Negotiation of letters of credit
- e. Execution of manual wire transfers
- f. Establish and maintain internet based banking platform for cp issuance, fund transfers and reporting
- g. Payment of interest, principal and fees on outstanding debt

(3) Arrange operating credit facilities

a. Negotiate credit agreements

i. Determine terms and conditions

ii. Negotiate pricing and term

b. Manage syndication process

c. Obtain BCUC approval

(4) Negotiate bank-service fees

(5) Treasury-related controls and compliance

a. Develop and monitor control and compliance procedures for key Treasury procedures

(6) Compliance reporting

a. Prepare and file required compliance reports with third parties

i. Lenders, securities commissions, BCUC

(7) Hedging of interest rate and foreign exchange risks

a. Develop financial hedging plans as required

b. Negotiation of required documentation

c. Execution of derivative transaction

(8) Prepare Derivatives Policies and Procedures;

(9) Counterparty Credit Risk Management;

a. Review credit worthiness of counterparties

b. Determine appropriate credit limits for counterparties

c. Determine requirement for credit support

d. Negotiate appropriate credit support documentation

(10) Interest rate and foreign exchange rate forecasting;

(11) Regulatory submissions with respect to ROE, capital structure and financing matters;

(12) Capital structure review and maintenance; and

(13) Provide education and related materials from training courses and seminars attended by Treasury staff.

<u>Investor Relations</u>

(1) Manage the Rating Agency Process;

(2) Maintain investment banker and debt investor relationships;

(3) Maintain banking and money market dealer relationships;

(4) Investor and Shareholder communication;

(5) Assist in preparation of annual/quarterly disclosure documents; and

(6) Prepare annual report.

Corporate Development and Capital Management

(1) Manage the annual strategic planning cycle;

(2) Preparation and maintenance of the five year forecasting model used for strategic planning process and in the annual budgeting process;

(3) Provide financial analysis and evaluation of new projects and new initiatives;

(4) Manage the acquisition and divestiture activity;

(5) Provide project management and/or due diligence support where required; and

(6) Contract negotiation in support of business development initiatives.

External Reporting and Consolidation

(1) Consolidation and preparation of monthly financial statements for TGW and preparation of quarterly interim reports and annual audited financial statements;

(2) Preparation of monthly reporting journal entries (consolidation, tax, accruals, etc), analytical reviews of accounts and monthly financial review package

(3) Preparation of analysis required from prospectus and other security filing documents as requested by Treasury Department and senior management;

(4) Preparation of quarterly and annual report to the Audit Committee;

(5) Compilation of information in response to a variety of enquiries from operations, senior management and external bodies, such as the BCUC, external auditors and government agencies;

(6) Research current and emerging accounting policies in Canada, the US and under International Financial Reporting ("IFRS");

(7) Direct response to accounting authorities in both Canada, the US and IFRS with respect to exposure drafts and pronouncements;

(8) Project lead for Terasen on the implementation of IFRS;

(9) Provide accounting policy advice for such issues as consistency of presentation, alternative treatments and resolution of complicated accounting policies and ensure compliance with General Accepted Accounting Principles;

(10) Accounting advice and assistance as required.

Taxation Services

(1) Prepare year-end and quarterly tax provisions including preparing tax calculations and working papers for current tax expense, providing information for the calculation of FIT expense and reviewing FIT calculations, preparing or reviewing the necessary journal entries, assisting auditors with external audit review, preparing tax disclosures to the financial statements and analyzing Balance Sheet tax accounts;

(2) Prepare tax returns and all tax compliance work for TGW, including identification and research of technical issues, filing necessary elections, agreements and information returns, requesting post filing adjustments, and reviewing assessments and interest calculations;

(3) Calculate corporate tax instalments and arrange payment;

(4) Prepare or review tax information and calculations in support of rate cases, annual reviews and annual reports to the BCUC; participate in regulatory working groups to provide information and guidance on tax issues;

(5) Provide tax support for planning and forecasting groups; provide a strategic tax perspective into planning processes to optimize tax advantages for the Gas companies;

(6) Provide leadership, guidance and consultation to finance and operations leaders on income tax and commodity tax issues; find tax solutions to complex business issues;

(7) Monitor, identify and research tax issues resulting from tax law changes, accounting changes (such as IFRS) or business opportunities to make sound recommendations to management;

(8) Interpret impact of industry issues on tax; participate in industry group tax committees such as Canadian Gas Association and make submissions to government bodies on issues relevant to the industry;

(9) Monitor GST and PST (including Social Services Tax, Carbon Tax, ICE levy), including identifying issues and researching technical enquiries, coordinating filing of necessary elections, responding to queries on the application of GST or PST to particular transactions, training employees on the application of commodity taxes to revenues, disbursements and transactions, advising employees of commodity tax changes; advising in the implementation of new taxes;

(10) Monitor tax implications of payroll and employee benefits including advising on taxable benefits and related calculations, payroll tax issues, and pension plan tax issues;

(11) Coordinate tax audits (federal income tax, LCT, GST , various PST), provide auditors access to data, research and provide answers to auditor's requests and negotiable beneficial resolution of proposed adjustments;

(12) Prepare and file Notices of Objection and Appeal letters and coordinate legal appeals with internal and external counsel; negotiate with tax authorities with a view to minimizing ultimate liabilities;

(13) Establish and monitor tax department controls and ensure adherence to tax policies;

(14) Provide ongoing training, guidance and support to tax group employees to enhance their performance levels and career development.

Internal Audit

(1) Develop, plan and conduct audits/reviews of areas or processes of particular interest or of identified risk and prepare internal audit reports;

(2) Conduct annual risks assessment process in conjunction with the Enterprise Risk Management group;

(3) Monitor and evaluate the effectiveness and efficiency of controls throughout the year and summarize results to the Audit Committee of the Board of Directors;

(4) Ensure that the TGW Code of Business Conduct compliance management is effective by conducting the annual compliance reviews and acting as a resource when issues arise with respect to the Code of Business Conduct;

(5) Monitor the Whistle Blower Ethics line and address issues as they arise;

(6) Participate on various committees in the capacity of ex-officio to provide oversight and value add;

(7) Undertake work at the request of the BC Utilities Commission regarding the activities and operations of TGW.

(8) Provide annual reports summarizing Internal Audit activities and findings to the BCUC as well as other reports of regulatory compliance;

(9) Conduct post implementation reviews of major capital projects and acquisitions and report results to the Audit Committee;

(10) Provide assistance to the external auditors in completing their external financial audits; and

(11) Coordinate activities of various internal and external assurance providers to ensure proper coverage and minimize duplication of efforts.

Risk Management and Insurance Services

(1) Ensure compliance with the TSX requirements on risk management by ensuring that the Board of Directors understand the principal risks of all aspects of business that TGW is engaged in, and ensuring that there are systems in place that effectively manage and monitor those risks with a view to the long term viability of the TGW;

(2) Arrange for coverage based on assessed potential risk of damage or loss in asset values, disruptions in operations or potential legal liabilities;

(3) Advise dollar value of coverage required, most appropriate coverage and proper services required;

(4) Provide a single insurance program to achieve economies of scales and cost reductions;

(5) Work with broker in negotiating renewals and adequacy of coverage;

(6) Ensure competitive terms and consider all available options;

(7) Establish procedures and provide assistance and guidance in the reporting, handling, compiling, negotiating and settlement of claims;

(8) Provide mechanism for appropriate and timely local resolution of third party damage claims below a given threshold and payment of same;

(9) Conduct of review of contractual agreements to protect TGW from unnecessary assumption of risks;

(10) Coordinate Risk Management's group participating in industry associations and education seminars;

(11) Establish loss control standards to help ensure consistent and high degree of loss; prevention in all operating units and minimize impact when they do occur;

(12) Ensure familiarity with policies and wordings;

(13) Encourage and establish procedures for loss control;

(14) Administer Certificates of Insurance;

(15) Preparation of management reports;

(16) Provide additional insurance for individual construction projects, as required; and

(17) Provide bonding as required.

Corporate Secretary's Office

(1) Ensure all continuous disclosure and governance activities required by external regulators and third parties are appropriately carried out, including Securities filings and BC Business Corporations Act requirements; and

(2) Manage the relationship and corporate activities of the Board of Directors.

(3) Prepare materials for Board of Directors and minutes.

(4) Track and maintain corporate records.

(5) Assist in preparation of corporate documentation and providing corporate information to internal and external parties.

Legal Department

(1) Provide all legal services to TGW other than those outsourced to outside legal counsel;

(2) Direct the provision and management of outside legal services, primarily litigation, to TGW;

(3) Provide management of all litigation;

(4) Provide legal counsel on regulatory, environmental, marketing, employment, and intellectual property;

(5) Ensure legal compliance for press release, financial reports and other disclosure documents;

(6) Advise TGW on legal issues that may arise including claims, actions, real estate and other property transactions, and contracts, including the purchase of goods and services by TGW; and

(7) Provide general miscellaneous legal support and advice to management.

Human Resources Compensation and Planning

(1) Consult with management on the maintenance, development and governance of employees and retiree benefit programs, pension plans, employee savings plans and employee assistance programs;

(2) Provide assistance on annual wage and salary increases, providing labour market comparisons, establishing and implementing ad hoc increases for long term disability and pension recipients;

(3) Ensure that employment practices are in compliance with applicable regulations and legislation through development and administration of appropriate corporate policies and procedures;

(4) Consulting and direction on disability management guidelines and policy;

(5) Oversee the annual preparation of the executive succession plan and present the plan to the Management Resources Committee and to the Board of Directors;

(6) Corporate governance and direction regarding benefits carriers, benefits and pension consultants, financial services providers;

(7) Corporate reporting to legislative bodies, CCRA, Statistics Canada, Pension Standards, as required; and

(8) Corporate governance of salary and benefit administration, including executive and management compensation.

SERVICES PROVIDED BY FORTIS INC. ("FORTIS")

Executive Function

President & CEO

A. *Strategic Direction*

1. Present annually to the Board of Directors of Fortis (the "Board") a strategic plan and a business plan which must (a) be designed to achieve the corporate objectives together with an appropriate set of performance measures, (b) identify the principal strategic and operational risks of the business, and (c) include appropriate methods to manage the risks;
2. Obtain Board approval for the strategic plan and the business plans of Fortis as a precondition to the implementation of such plans;
3. Obtain Board approval for the procurement, allocation, and disposition of corporate resources for Fortis as a precondition to such procurement, allocation or disposition of such resources either;
    a. in the approved Business Plan; or
    b. by specific authorization of an asset transaction consistent with current business activities in an amount in excess of $XX [insert amount] million ($XX [insert amount] million annual aggregate) and for any share transaction (other than increased investment in an existing affiliate within the transaction size parameters noted above); and
4. Communicate the principal objectives and strategic plan for Fortis throughout Fortis.

B. *Leadership and Management of Fortis*

1. Lead Fortis with vision and values that are well understood, widely supported and consistently followed;
2. Foster a corporate culture which promotes ethical practices, personal integrity and the fulfilment of social responsibilities;
3. Create the appropriate environment to stimulate employee morale and productivity;
4. Manage change proactively;
5. Ensure continuous improvement in the quality and value of the products and services provided by Fortis;
6. Ensure that Fortis achieves and maintains satisfactory competitive positions within its industries; and
7. Serve as a director of Fortis.

C. *Management and Organization Structure*

1. Provide advice to the Board on the appointment of all officers of Fortis;
2. Assist the Board in establishing the limits of delegated authority and responsibility in conducting Fortis's business;
3. Provide annually to the Board, an evaluation of the performance of each senior manager who reports to the CEO;
4. Present for approval to the Board, an annual plan which will provide for the development and succession of senior managers of Fortis in a timely fashion;
5. Generally develop, attract, and retain a highly motivated, effective management team; and
6. Obtain Board approval for any proposed significant or material change in the organizational structure of Fortis as a precondition to the implementation of such changes.

D. *Finances, Controls and Internal Systems*

1. Consistently strive to achieve Fortis's annual and long-term financial goals and objectives;
2. Assist the Board in establishing an appropriate capital structure for Fortis;
3. Ensure that Fortis has systems in place to effectively monitor and manage the principal risks related to the operation of the business(es);
4. Establish and maintain the integrity of Fortis's financial controls and reporting systems and compliance of the financial information with appropriate accounting principles;
5. Establish and monitor processes and systems designed to ensure compliance with all applicable laws by Fortis, its officers and employees; and
6. Provide certification of financial matters, including the completeness and accuracy of Fortis's financial statements and, where necessary, matters relating to internal controls over financial reporting.

E. *Employee Relations*

1. Ensure that a process is in place to monitor compliance with the ethical standards to be observed by all officers and employees of Fortis, and ensure that a process is in place to monitor divergence from the ethical standards to be observed by all employees; and
2. Establish and maintain effective communications with employees of Fortis.

F. *External Communication*

1. Assist the Board in establishing and maintaining an effective communications policy with shareholders, the financial community, the media, the community at large and other stakeholders;

2. Ensure that Fortis contributes, and is perceived to contribute, to the well-being of the communities it serves; and
3. Serve as the principal representative and spokesperson of Fortis.

G. Board Relations

1. Keep the Board adequately informed, on a timely basis, with respect to all events and information which the CEO believes might materially affect Fortis, its performance, prospects, and image;
2. Provide the assistance necessary for the Chair of the Board and committees of the Board to carry out their duties;
3. Be entitled to attend all meetings of Board committees and provide Board committees the assistance necessary to carry out their mandates;
4. Assist the Board in reviewing and maintaining an up-to-date position description for the President and CEO of Fortis; and
5. Report to the Board on material use of outside consultants.

VP Finance and CFO

1. Advise and assist the Chairman of the Board and President and CEO in the development of strategies and goals in the financial planning and structure of the Group and in the control of the Company's business operations.
2. Keep the CEO informed of all relevant financial information and report on the financial status and performance of all companies in the group to the Board of Directors of Fortis Inc.
3. Responsible for all aspects of investor relations program, including shareholder communications and shareholder meetings.
4. Liaison with the investment community and market surveillance.
5. Ensure that procedures and systems necessary to maintain proper records and to afford adequate accounting controls and services are implemented throughout the organization.
6. Ensure that uniform financial policies and procedures are adhered to throughout the organization.
7. Ensure the development and maintenance of timely financial information systems.
8. Develop and maintain effective internal and external audit activities and recommend proper financial controls.
9. Develop and maintain suitable budgeting procedures and reviews.
10. Direct the planning and control of corporate cash requirements and major banking relationships.

11. Review capital expenditure plans and budgeting.
12. Plan and direct corporate financing.
13. Recommend guidelines for financial transactions between companies in the Fortis Group.
14. Ensure that adequate financial personnel resources are retained and appropriately assigned throughout the group.
15. Appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions. As demanded, manage external financial consulting resources.
16. Maintain an awareness of changes in practice and procedure within the professional accounting field.
17. Act as CFO of subsidiary organizations when required.

General Counsel & Corporate Secretary

1. Prepare schedules, notices, agendas, resolutions, and minutes for the Boards of Directors of Fortis Inc. and selected subsidiaries and affiliates.
2. Coordination of all communications to Board of Directors.
3. Operation of share purchase plans.
4. Preparation of security documents including Management Information Circulars, Annual Information Forms and prospectuses.
5. Responsible for regulatory compliance, including annual returns to the registries of companies, dividend disclosure, filing of annual and quarterly reports, reports to stock exchanges, notices of Material Change, and Insider Reports.
6. Provide legal services to all corporations in the Fortis Group including, when necessary, engagement of outside legal services.

Treasury and Taxation Function

1. Manage equity financing, including both common and preference shares, and related prospectuses
2. Manage debt financing, including long-term debt and credit facility borrowings as well as borrowing rates
3. Maintaining the capital structure
4. Assist the VP finance and CFO appraise and implement the necessary financial analysis of acquisition and/or divestiture decisions
5. Cash management and forecasting activities – including dividend and interest payments and equity injections required by subsidiaries

6. Managing cash requirements of subsidiaries, as required, as it relates to intercompany loans and required equity injections
7. Debt covenant calculations and monitoring
8. Managing hedging activities related to US dollar debt
9. Preparation of annual corporate tax returns and related foreign affiliate corporate tax returns
10. Calculation of quarterly and annual Fortis Inc. corporate tax provision
11. Responsibility for utilization of non-capital and capital loss carryforwards of Fortis Inc. and coordination of tax utilization plans with applicable subsidiaries
12. Managing corporate reorganizations and tax planning
13. Manage tax implications of payroll and employee benefits including researching and advising on taxable benefits, CPP, EI and payroll tax issues
14. Preparing Fortis Inc. employee T4's, including preparing taxable benefit calculations
15. Coordination of Fortis Inc. corporate income tax or HST audits
16. Tax research associated with tax issues and changes in tax laws

<u>Investor Relations Function</u>

1. Manage analyst communications – including review of analysts' commentaries/research reports, conduct quarterly conference calls and respond to general analyst research inquiries.
2. Manage investor communications – including the preparation and delivery of investor presentations, road shows, web casts, teleconferences and one-on-one meetings with existing and prospective shareholders
3. Manage shareholder communications – including responding to general shareholder inquiries and the preparation, delivery and filing of documentation for quarterly and annual mailings (i.e., quarterly reports, annual report, proxy, management information circular and annual information form).
4. Coordination and preparation of Fortis's Annual Meeting including preparation of the Executive's presentation to shareholders.
5. Coordination of solicitation of proxies.
6. Preparation of Quarterly Investor Relations Reports to the Board of Directors.
7. Preparation, coordination and dissemination of media releases to newswire agencies, websites and distribution lists.
8. Monitor and maintain Fortis's media coverage.
9. Develop, host and maintain the Fortis Inc. website.

10. Monitor the websites of the Fortis Group of Companies.
11. Monitor and research the market and investment community through Bloomberg, ThomsonOne, TSX, etc.
12. Manage and maintain the Fortis Inc. dividend reinvestment and share purchase plans (i.e., Dividend Reinvestment and Share Purchase Plan, Consumer Share Purchase Plan and Employee Share Purchase Plan)
13. Coordination and preparation of Fortis's consolidated Strategic Issues document and presentation to the Board of Directors.
14. Preparation of Fortis's consolidated Business Plan presentation to the Board of Directors.
15. Manage public relations – including conference participation, the preparation of Executive speeches and responding to media inquiries.

<u>Financial Reporting Function</u>

1. Preparation of quarterly and annual consolidated financial statements and notes to the financial statements and the related management discussion and analysis
2. Preparation of monthly internal consolidated and non-consolidated financial statements of Fortis Inc.
3. Coordination with external auditors of the annual audit of the consolidated financial statements and quarterly review of consolidated financial statements.
4. Preparation and analysis of financial information required for prospectus and other security filing documents
5. Preparation of the Annual Information Form and providing assistance in the preparation of the Management Information Circular
6. Assisting in responding to reviews and queries of securities regulators related to continuous disclosure reporting
7. Research current and emerging accounting policies in Canada, US and that related to IFRS
8. Coordinate consistent accounting policy treatment across the Fortis group of companies related to presentation, alternative treatments and resolution of complex accounting policies to ensure compliance with GAAP
9. Oversight and coordination of conversion to International Financial Reporting Standards across the Fortis Group of companies – including coordinating research, organizing working group and steering committee sessions to discuss and resolve ongoing issues and progress, monitoring and directing progress of the overall conversion and coordination with the external auditors

10. Coordination and preparation of consolidated Business Plan document and reporting to the Board of Directors
11. Preparation of quarterly forecasted consolidated earnings and EPS
12. Responsibility for maintaining internal controls over financial reporting at Fortis Inc.

<u>Internal Audit Function</u>

1. Performs internal audit activities at Fortis Inc including:
    a. coordinating the Fortis Inc. CEO and CFO internal controls certification process through maintenance of financial process documentation and annual evaluation of internal controls over financial reporting and disclosure controls. Involves ensuring that all Fortis subsidiaries are fully compliant in order to support certification by the parent company;
    b. performing quality assurance reviews of Fortis Inc. continuous disclosures documents prior to public filing;
    c. performing annual reviews of Fortis Inc. statutory obligations and executive expenditures;
    d. reporting internal audit activities to the Fortis Inc. Audit Committee on a regular basis; and
    e. coordinating compliance with corporate governance requirements

2. Provides oversight over the internal audit function at the Fortis subsidiary companies to:
    a. ensure corporate-wide consistency in the application of internal audit methodologies and practices and in the reporting of audit results to management and audit committees;
    b. coordinate annual audit program planning to ensure critical risk areas are addressed;
    c. coordinate corporate-wide audit projects;
    d. identify opportunities for audit resource and information sharing between the subsidiary internal audit groups;
    e. oversees audit program planning and reviews internal audit reports to management and Audit Committees for these subsidiaries with limited internal audit resources;
3. Administers and monitors reports of allegations of suspected improper conduct or wrong doing via Fortis's ethics reporting system
4. Development of a company-wide Enterprise Risk Management program approach

Board of Directors

The Board of Directors of Fortis Inc. is responsible for the stewardship of Fortis. The Board will supervise the management of the business and affairs of Fortis and, in particular, will:

A. Strategic Planning and Risk Management

1. Adopt a strategic planning process and approve, on an annual basis, a strategic plan for Fortis which considers, among other things, the opportunities and risks of the business;
2. Monitor the implementation and effectiveness of the approved strategic and business plan;
3. Assist the CEO in identifying the principal risks of Fortis's business and the implementation of appropriate systems to manage such risks;

B. Management and Human Resources

1. Select, appoint and evaluate the CEO, and determine the terms of the CEO's employment with Fortis;
2. In consultation with the CEO, appoint all officers of Fortis and determine the terms of employment, training, development and succession of senior management (including the processes for appointing, training and evaluating senior management);
3. To the extent feasible, satisfy itself as to the integrity of the CEO and other officers and the creation of a culture of integrity throughout Fortis;

C. Finances, Controls and Internal Systems

1. Review and approve all material transactions including acquisitions, divestitures, dividends, capital allocations, expenditures and other transactions which exceed threshold amounts set by the Board (including equity contributions to subsidiaries to support the investment in rate base to serve customers;
2. Evaluate Fortis's internal controls relating to financial and management information systems;

D. Communications

1. Adopt a communication policy that seeks to ensure that effective communications, including statutory communication and disclosure, are established and maintained with employees, shareholders, the financial community, the media, the community at large and other security holders of Fortis;

2. Establish procedures to receive feedback from stakeholders of Fortis and communications to the independent directors as a group;

E. Governance

1. Develop Fortis's approach to corporate governance issues, principles practices and disclosure;
2. Establish appropriate procedures to evaluate director independence standards and allow the Board to function independently of management;
3. Appoint from among the directors an audit committee and such other committees of the Board as deemed appropriate and delegate responsibilities thereto in accordance with their mandates;
4. Develop and monitor policies governing the operation of subsidiaries through exercise of Fortis's shareholder positions in such subsidiaries;
5. Develop and monitor compliance with Fortis's code of conduct;
6. Set expectations and responsibilities of directors, including attendance at, preparation for and participation in meetings; and
7. Evaluate and review the performance of the Board, each of its committees and its members.

THIS AMENDING AGREEMENT is made effective January 1, 2012 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (WHISTLER) INC.
(formerly Terasen Gas (Whistler) Inc.)
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEW")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
(formerly Terasen Inc.)
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEWI and FHI entered into an agreement dated as of January 1, 2010 (the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. All references to "Terasen Gas (Whistler) Inc." and "TGW" shall be deleted and replaced with "FortisBC Energy (Whistler) Inc." and "FEW" respectively.

3. All references to "Terasen Inc." and "Terasen" shall be deleted and replaced with "FortisBC Holdings Inc." and "FHI" respectively.

4. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEW agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation the amount of $48,500 per annum for the period of January 1, 2012 to December 31, 2012 on a take-or-pay basis and the amount of $50,200 per annum for the period of January 1, 2013 to December 31, 2013 on a take-or-pay basis."

5. This Amending Agreement shall be read together with the Agreement as modified.

6. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

7. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

8. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

9. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY (WHISTLER) INC.

By: ______________________

Roger Dall'Antonia
Title: Vice President, Finance & CFO

FORTISBC HOLDINGS INC.

By: ______________________

Scott Thomson
Title: Executive Vice President, Finance, Regulatory & Energy Supply

THIS AMENDING AGREEMENT #2 is made effective January 1, 2014 (the "Effective Date").

BETWEEN:

FORTISBC ENERGY (WHISTLER) INC.
16705 Fraser Highway
Surrey, British Columbia, V4N 0E8

(hereinafter referred to as "FEW")

OF THE FIRST PART

AND:

FORTISBC HOLDINGS INC.
10th Floor, 1111 West Georgia Street
Vancouver, British Columbia, V6E 4M4

(hereinafter referred to as "FHI")

OF THE SECOND PART

WHEREAS:

A. FEW and FHI entered into an agreement dated as of January 1, 2010 and amended by an Amending Agreement dated January 1, 2012 (collectively, the "Agreement"); and

B. The parties are now desirous of amending the Agreement on the following terms and conditions.

NOW THEREFORE, in consideration of the mutual promises herein and other good and valuable consideration (the receipt and sufficiency of which is hereby acknowledged), the parties hereby covenant and agree as follows:

1. In this Amending Agreement, capitalized words and expressions used shall have the same meanings as are respectively assigned to them in the Agreement.

2. Clause 3.1 shall be deleted and replaced with the following:

"3.1 Compensation for Services and Shared Costs

FEW agrees to pay to FHI for the Services to be provided and for a proportionate share of the common expenses incurred by FHI such as shareholder expenses and director compensation at an amount, on a take-or-pay basis, to be agreed upon in writing between FEW and FHI from time to time ."

3. This Amending Agreement shall be read together with the Agreement as modified.

4. This Amending Agreement shall be governed by and construed in accordance with the laws of the Province of British Columbia and the parties agree to attorn to the jurisdiction of the courts of British Columbia.

5. Words importing the singular include the plural and vice versa; words importing the masculine gender include the feminine and neuter genders; and words importing persons include individuals, sole proprietors, corporations, partnerships and unincorporated associations.

6. This Amending Agreement may be executed in counterparts with the same effect as if all parties had signed the same document. All counterparts will be construed together and will constitute one agreement.

7. All unamended terms and conditions shall remain in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amending Agreement effective the Effective Date.

FORTISBC ENERGY (WHISTLER) INC.

By: ______________________

Title: President & CEO

FORTISBC HOLDINGS INC.

By: ______________________

Title: CFO & Treasurer

FortisBC Holdings Inc.
10th Floor, 1111 West Georgia
Vancouver, BC V6E 4M3
Fax: 604-443-6540
www.fortisbc.com

January 1, 2014

FortisBC Energy (Whistler) Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Sir/Madam:

RE: Agreement between FortisBC Holdings Inc. ("FHI") and FortisBC Energy (Whistler) Inc. ("FEW") dated January 1, 2010, as amended on January 1, 2012 and January 1, 2014 (the "Agreement") – Compensation for Services and Shared Costs

Pursuant to Section 3.1 of the Agreement between FHI and FEW, we propose that compensation for services and shared costs payable by FEW to FHI for the Services shall be the amount of $51,000 CAD. This amount shall continue to be payable under the Agreement, until such time as the Agreement is terminated or expires or the parties agree in writing to amend this amount.

Please confirm your agreement to the aforementioned compensation amount by executing the acknowledgement below. Receipt by FHI of a copy of this acknowledgement signed by FEW shall constitute the mutually agreed upon sum payable by FEW to FHI under Section 3.1 of the Agreement.

Yours truly,

FORTISBC HOLDINGS INC.

Roger Dall'Antonia
Chief Financial Officer and Treasurer

ACKNOWLEDGEMENT

FEW hereby acknowledges and agrees to the compensation amount set forth herein, for the Services provided by FHI under the Agreement.

Dated at Surrey, BC, this 6th day of June, 2013.

FORTISBC ENERGY (WHISTLER) INC.
Per:

MC
Authorized Signature

Michele Leeners
Print Name

VP Finance & CFO
Title

Appendix F3

OVERHEADS CAPITALIZED STUDY

FortisBC Energy Inc.

Overhead Capitalization Methodology Review

June 10, 2013

Table of Contents

1. Executive Summary

KPMG was retained by FortisBC Energy Inc. ("FEI") to assist with their overhead capitalization study (the "Study"). The purpose of the Study is to review the overhead capitalization methodology and resulting overhead capitalization rate of FEI under U.S. Generally Accepted Accounting Principles ("U.S. GAAP"), including the application of regulatory accounting, in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 ("ASC 980") *Regulated Operations*. The overhead capitalization rate is defined by FEI as the percentage of Gross Operations and Maintenance ("O&M") costs, related to capital activity, which have not been directly charged to capital.

Within the utility industry in Canada, there is now a mix of financial reporting frameworks being applied. This is a result of the transition in Canada to International Financial Reporting Standards ("IFRS") which currently lacks an equivalent standard to U.S. GAAP's ASC 980, *Regulated Operations.* Rate-regulated utility entities in Canada had previously been applying the U.S. standard ASC 980 *Regulated Operations* following the guidance contained within Canadian GAAP from 2009 and prior to this had applied Canadian GAAP which had specific reference to rate regulated enterprises. Effective January 1, 2012 FEI adopted U.S. GAAP as its financial reporting framework in order to continue application of GAAP utilizing rate-regulated accounting. The application of ASC 980 *Regulated Operations* by the British Columbia Utilities Commission ("BCUC" or "Commission") is informed through the BCUC *Uniform System of Accounts Prescribed for Gas Utilities* which provides guidance on BCUC's views of acceptable overhead capitalization. This guidance is also supplemented by U.S. industry guidance Federal Energy and Regulatory Commission ("FERC") *Uniform System of Accounts.*

A previous overhead capitalization study for FEI dated June 10, 2009 was performed in anticipation of the adoption of IFRS. This current study provides a high-level summary of the similarities and differences between what may be capitalized under IFRS and what may be capitalized under U.S. GAAP.

No single regulatory guideline, statement or source exists that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes the types of indirect costs (i.e. those related to capital projects that have not been directly charged to those capital projects), that should be considered for capitalization for purposes of regulatory and financial reporting. There is limited guidance both from regulators and in U.S. GAAP in this area. Therefore, variations in practice exist due to the limitations of the available framework and the capitalization policies approved by the relevant utilities' regulator. Nonetheless, this topic has been the subject of discussion and comment and a body of evidence exists on the topic. From this evidence, a common principle arises:

That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association which is clearly related to capital activity.

In order to provide an objective and reasonable basis of determining overhead capitalization, FEI undertook a capital cost allocation study. Two methodologies were used in the study – a Survey-based Model and a Mathematical Model. Previously, the overhead capitalization rate for FEI was developed using the Survey-based Model approach.

These methodologies were evaluated based on a number of criteria to determine their appropriateness. The examination of the two models provides a basis for the comparison between both approaches and allows a context for the BCUC to better understand the range of possible capitalization percentages that exist within the interpretations required under the accounting standards.

The Study utilized the BCUC approved 2013 FEI budget (the "2013 budget") figures pursuant to BCUC order G-44-12.

KPMG finds the FEI Survey-based capital cost allocation methodology, as detailed in Section 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities that have not been directly charged to capital projects (i.e. overhead capitalization). This methodology is consistent with internally generated evaluation criteria and practice established by the external guidance (referred to in this report), in particular the requirements of U.S. GAAP under ASC 980 *Regulated Operations*.

Based on the Survey-based methodology applied by FEI, and using the 2013 budget figures, the costs related to capital activities that have not been directly charged to capital projects, as a percentage of total O&M cost, is estimated to be approximately **12 percent**.

In the absence of future significant regulatory, accounting and organizational changes, the application of this rate in future periods may continue to be appropriate.

2. Purpose of Report

2.1 Project Scope

FortisBC Energy Utilities ("FEU") – collectively being FEI, FortisBC Energy Inc. Fort Nelson Service Area ("Fort Nelson"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy Whistler Inc. ("FEW") – has been asked by the BCUC to undertake a study related to the capitalization of overhead. This is Directive No. 29, Appendix A Page 4 of BCUC Order G-44-12 issued as a result of the FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application. The Directive in Order G-44-12 with respect to capitalized overhead was as follows:

"*Given the various changes in accounting standards and the desired expansion of the FEU's customer offerings and new business activities, the Commission Panel directs the FEU to update their capitalized overhead methodology using relevant accounting standards in the next test period. The Commission Panel further directs the FEU to obtain a report on this methodology from a qualified independent third party for inclusion in their next revenue requirements application.*"

While this Direction was provided to FEU, this report's scope is limited to FEI only.

This report has examined the appropriateness of the capitalization of capital overhead costs which have not been directly charged to capital. Within the context of the study, it is important to note that capitalized overhead costs should be distinguished from costs charged directly to capital. These are costs that are charged directly to specific identified capital projects and therefore form part of the direct capital cost of the associated assets. Such costs include the costs of materials and construction labour, as well as any purchased services (e.g. outside contracting) that may be associated with installation or construction of the asset. Such direct charges are removed from the costs which are to be allocated to overhead under both the Mathematical and Survey-based Models below. That is, the O&M costs which are allocated to capital are allocated net of the direct charges.

"Capitalized overhead," in contrast, reflects those costs that relate to capital projects but that have not been specifically identified with or charged directly to any individual capital project.

Costs associated with capital activities, not directly charged to capital projects are capitalized on the basis of predetermined rates established by management upon review and approval by the BCUC. This methodology ensures the apportionment of capital related O&M costs to capitalized activities is reasonable.

2.2 Accounting frameworks

For accounting periods commencing after January 1, 2012, the FEU entities have elected to apply U.S. GAAP, which has been approved by the BCUC in Order G-117-11. This framework includes the application of ASC 980 *Regulated Operations*. Prior to that time, the FEU reported under what is now Part V of the Canadian Institute of Chartered Accountants Handbook.

Accordingly, the scope of this report is to provide a review of capital overhead cost allocation methodology and resulting overhead capitalization rate of FEI under the U.S. GAAP financial reporting framework. The BCUC confirmed that the FEU is required to have the capitalized overhead study prepared under U.S. GAAP with consideration of ASC 980[1].

In addition, the BCUC has also requested[2] that a study be prepared under U.S. GAAP *without* consideration of ASC 980. However, the BCUC will waive such a requirement should the FEU file its previous IFRS study[3] with its next Revenue Requirements Application ("RRA") as a substitute and have a third party examine any differences between what would be included under IFRS and what might be included under U.S. GAAP and their impact, if any, on the IFRS study with its next RRA. These high-level similarities and differences between IFRS and U.S. GAAP are discussed in this report in Section 4.

For this current FEI Study, the basis of the Study is the 2013 budget figures. In the absence of future significant regulatory, accounting and organizational changes, the application of this rate in future periods may continue to be appropriate.

In summary, this report:

- Addresses the accounting policies under the U.S. GAAP framework followed by FEI;
- Examines the high-level similarities and differences between U.S. GAAP and IFRS frameworks with respect to accounting for overhead capitalization;
- Reviews the capital overhead cost allocation methodology applied by FEI;
- Assesses the reasonableness of the activities allocated to capital;
- Assesses the reasonableness of the cost drivers; and
- Presents the resulting overhead capitalization rate.

2.3 Scope Limitations

This section provides details of the limitations of this Study. These are as follows:

Management responsibility:

FEI's capitalization methodology report is the responsibility of management who also maintain responsibility for the accuracy and completeness of the data and information associated with the capital cost allocation methodology and associated costs.

[1] Per Commission filed letter, Log No. 41870.
[2] Ibid.
[3] Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. 2010/11 Overhead Capitalization Methodology Review, dated June 10, 2009 by KPMG.

KPMG engagement:

Our engagement is to comment on the reasonableness of the capital overhead cost allocation methodology, in the context of FEI's reporting under U.S. GAAP, inclusive of ASC 980, and undertake the steps outlined in Section 5 of this report.

This evaluation does not constitute an audit of the capital overhead cost allocation methodology, associated costs or the resulting capitalization rate. Accordingly, we do not express an opinion on such matters. For the avoidance of doubt, KPMG has neither audited nor reviewed the underlying fiscal 2013 approved budgeted O&M results and costs that form the basis of the percentages capitalized per FEI's Study. However we have outlined the steps undertaken to assess the accuracy of the underlying data in Sections 5 and 7.5.

KPMG assessed the proposed capital cost allocation methodology using fiscal 2013 approved budgeted O&M results, as provided by management. Our findings and conclusions are therefore limited accordingly.

The information contained herein is for the internal use of FortisBC management, the Audit and Risk Committee, and Board of Directors. It is understood that this report will be distributed by FortisBC externally to the BCUC as part of the regulatory process and by other Fortis subsidiaries to their regulators. KPMG disclaim any responsibility or liability for losses, damages, or costs incurred by anyone as a result of any external circulation, publication, reproduction, or use of the information contained herein.

2.4 Report Structure

This report is structure as follows:

- **Section 1: Executive Summary** - Includes a brief discussion of KPMG's review approach and summary of findings.
- **Section 2: Purpose of Report** - Outlines the structure of the report and provides a brief explanation of each section.
- **Section 3: Background** - Provides an overview of the organizational structure, GAAP changes for the Company, and previous regulatory filings.
- **Section 4: Financial Reporting Framework** - Outlines the applicable financial reporting framework guidance for U.S. GAAP and IFRS, and available regulatory guidance including BCUC's *Uniform System of Accounts Prescribed for Gas Utilities* and FERC's *Uniform System of Accounts.*
- **Section 5**: **KPMG Approach** - Provides an explanation of KPMG's approach to assessing FEI's capital cost allocation methodology including the criteria used by KPMG during our analysis. This scope of the evaluation was agreed between KPMG and FEI and the evaluation approach is based on KPMG's past practice of similar capital cost allocation methodology studies undertaken by other Canadian utility companies.

- **Section 6: FEI Overhead Capitalization Methodology and Results** - Provides a high level summary of the components of the overhead capitalization methodology.
- **Section 7: KPMG Evaluation** - Provides KPMG's findings as to the reasonableness of the capital cost allocation methodology.
- **Appendices:**
    - **Appendix A** - External survey
    - **Appendix B** - Capitalized overhead survey
    - **Appendix C** - Detailed listing of Accounting Guidance

3. Background

3.1 Application of U.S. GAAP

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that IFRS would replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on or after January 1, 2011. This introduction was eventually delayed for rate-regulated utility entities due to delays in the development of an IFRS rate-regulated standard equivalent to ASC 980. Rate-regulated utility entities in Canada had previously been applying the U.S. standard ASC 980 *Regulated Operations* following the guidance contained within Canadian GAAP from 2009 and prior to this had applied Canadian GAAP which had specific reference to rate regulated enterprises.

As a result of the absence of a rate-regulated standard being developed in IFRS, a number of rate-regulated utility entities in Canada have adopted U.S. GAAP. Appendix A to this report contains details of the accounting frameworks being applied by a sample of the Canadian utility industry.

FEI abandoned plans to adopt IFRS in 2011 and applied for and received BCUC approval to adopt U.S. GAAP for regulatory accounting effective 2012 through to 2014 (pursuant to Commission Order G-117-11).

3.2 Previous Capital Overhead Rate Submissions

KPMG previously issued to Terasen Gas Inc. (now FEI) and Terasen Gas (Vancouver Island) Inc. (now FEVI), a report dated June 10, 2009 on the overhead capitalization methodology for the 2010-2011 Revenue Requirement Application ("the 2010-2011 RRA"). That report was prepared under the framework of IFRS at that time as the FEU had planned to adopt IFRS starting in 2011. That study recommended an overhead capitalization rate as a percentage of total O&M costs of approximately **8%** for Terasen Gas Inc.

In the 2010-2011 Negotiated Settlement Agreement for both Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. and approved for Terasen Gas (Fort Nelson) and Terasen Gas (Whistler) Inc., the overhead capitalization rate approved by the BCUC was **14%**.

On May 4, 2011, in the FEU's 2012-2013 RRA, the FEU applied to maintain the capitalized overhead rate consistent with the **14%** which was agreed to in the 2010-2011 Negotiated Settlement Agreement. The rate was approved by the BCUC in Order G-44-12, however the BCUC decision noted that "*the FEU have since abandoned plans to adopt IFRS in either 2011 or 2012 and have received Commission approval in the U.S. GAAP Decision to adopt U.S. GAAP for regulatory purposes in 2012-2014, under which capitalized overhead treatment is not noted as a variance from the FEU's current treatment*" and therefore the capital overhead treatment was directed to be reviewed by the Company.

4. Financial reporting framework

4.1 FEI Capitalization Policy

FEI follows the available U.S. and regulatory accounting guidance. FEI applies the accounting guidance following a hierarchy based model. This hierarchy is as follows:

a) Utilize available U.S. GAAP guidance, including ASC 980 (discussed in Section 4.2);
b) Utilize available guidance from BCUC *Uniform System of Accounts Prescribed for Gas Utilities* (discussed in Section 4.3); and
c) Utilize FERC's *Uniform System of Accounts* (discussed in Section 4.3).

4.2 U.S. Generally Accepted Accounting Principles

There is limited explicit guidance, definition or discussion of the treatment of the capitalization of overhead under U.S. GAAP. However, there is U.S. GAAP literature that provides guidance on asset accounting and accounting for rate-regulated activities. The main sources of guidance under U.S. GAAP are as follows:

- ASC 360 *Property, Plant and Equipment*
- ASC 720 *Other expenses*
- ASC 970 *Real Estate*
- ASC 980 *Regulated Operations*
- Statement of Position, *Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment* Financial Reporting Executive Committee of the AICPA proposed standard, not adopted.

ASC 360-10 defines the cost of property, plant and equipment as "all costs necessary to bring it to the condition and location necessary for its intended use". Further guidance is provided within ASC 970 *Real Estate* which categorises capitalized costs into two types:

- **Direct costs** (termed "project costs" in ASC 970). These are defined as "*costs clearly associated with the acquisition, development, and construction of a real estate project*".
- **Indirect costs.** These are costs "*incurred after the acquisition of the property, such as construction administration (for example, the costs associated with a field office at a project site and the administrative personnel that staff the office), legal fees, and various office costs, that clearly relate to projects under development or construction. Examples of office costs that may be considered indirect project costs are cost accounting, design, and other departments providing services that are clearly related to real estate projects*". Specifically, ASC 970-360-25-3 states "*Indirect project costs that relate to several projects shall be capitalized and allocated to the projects to which the costs relate.*"

The application of ASC 980 *Regulated Operations* allows a rate regulated entity to capitalize costs that normally would be expensed if the costs are "allowable costs" for rate making purposes. Allowable costs can be actual or estimated and there must be reasonable assurance that the regulator will permit recovery of the costs in rates. Specifically, ASC 980-340 states the following:

"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."

As a result of the above, if a cost is approved by a regulator and is expected to be recovered from customers in future rates, then that cost may be capitalized under ASC 980. In absence of ASC 980 such costs may be required to be expensed if they do not meet the capitalization criteria of other standards.

4.3 Available regulatory guidance

The ability to capitalize costs under ASC 980 is dependent on the actions of the regulator. With respect to the capitalization of overhead, the BCUC's *Uniform System of Accounts Prescribed for Gas Utilities* provides a basis of reference to what the BCUC may allow to be capitalized under ASC 980 *Regulated Operations*. The Uniform System of Accounts includes the following guidance:

"*Cost of overhead charged to construction includes engineering, supervision, administrative salaries and expenses, construction engineering and supervision, legal expenses, taxes and other similar items. The assignment of overhead costs to particular jobs or units shall be on the basis of actual and reasonable costs."*

Similar guidance is provided by the U.S. energy commission, FERC, in its *Uniform System of Accounts*. Though FERC has no jurisdiction within Canada, the guidance of FERC is indicative of industry practice. The FERC *Uniform System of Accounts* states:

"All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such

costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired."

Within the utility industry, there is no single regulatory guideline, statement or source that exists that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes the types of indirect costs (i.e. those related to capital projects that have not been directly charged to those capital projects), that should be considered for capitalization for purposes of regulatory and financial reporting. U.S. GAAP provides very limited guidance in this area. Therefore, variations in practice exist due to the limitations of the available framework. However, this topic has been the subject of discussion and comment and a body of evidence exists on the topic. From this evidence, a common principle arises:

That any assignment of indirect costs to a capital project should be done based upon some reasonable causal link or association with the capital activity.

Any definition or standard that the FEI adopts should apply this basic principle.

4.4 International Financial Reporting Standards

Per the Commission filed letter (Log No. 41870), the BCUC has also requested a summary of the differences between IFRS and U.S. GAAP with respect to overhead cost capitalization. As noted previously in this report, there is at present no comparable guidance under IFRS to ASC 980 *Regulated Operations*. Accordingly, the actions of a regulator do not create assets (or liabilities) which may be deferred under IFRS. This is the primary difference between IFRS and U.S. GAAP with respect to overhead costs which may be capitalized between the two GAAP frameworks.

The guidance for the capitalization of overhead is provided under the International Accounting Standards Board's ("IASB") IAS 16 *Property, Plant and Equipment*. IAS 16 states that the cost of an item of property, plant and equipment comprises "*any costs* ***directly attributable*** *to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management*". The guidance provides examples of "directly attributable" costs, as follows:

> "(*a) costs of employee benefits (as defined in IAS 19 Employee Benefits) arising directly from the construction or acquisition of the item of property, plant and equipment;*
> *(b) costs of site preparation;*
> *(c) initial delivery and handling costs;*
> *(d) installation and assembly costs;*

> *(e) costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition (such as samples produced when testing equipment); and*
> *(f) professional fees*."

The guidance also provides examples of costs not eligible for capitalization, which include "administration and other general overhead costs."

As such, there are differences in wording used by IAS 16 and the US GAAP standards. However, it is the inclusion of ASC 980 *Regulated Operations* that produces a material difference in the overhead costs eligible for capitalization from U.S. GAAP.

4.5 Summary

Due to the absence of detailed guidance for each and every type of capital activity in the US standards, there is a degree of interpretation required in the application of the standards. Under IFRS, there is not a rate-regulated standard and hence the actions of a regulator cannot be used to justify the capitalization of costs.

As a result, the common principle and underlying methodologies employed by FEI for capitalizing costs related to capital activities that have not been directly charged to capital projects reflects a consistent approach under US GAAP. Namely, that any assignment of costs related to capital activity that have not been directly charged to a capital project should be done based upon some reasonable causal link or association with the capital activity.

5. KPMG Approach

This section summarizes KPMG's approach to completing the review of the Company's overhead capitalization methodology and related costs. Our work plan was developed in collaboration with management in order to meet the objectives of this review. Our work plan incorporated the following steps:

- **Step 1: Reviewed company approach**. In this step, KPMG discussed with management the nature and extent of both the survey approach used to evaluate the capitalization of overhead, including the formulation of questions used in the survey approach, and also the mathematical model approach. Both are discussed further in Section 6. We reviewed supporting documentation and previous relevant regulatory filings to gain a better understanding of the previous approaches adopted to capitalizing costs to capital activities
- **Step 2: Participated in interviews with company officials**. In this step, KPMG participated in various interviews held by FEI with senior representatives from the operating areas. The purpose of this step was to gain an understanding of the specific activities within FEI that may be related to capital. This step also provided KPMG with a good understanding of FEI's organizational structure and its approach to the acquisition, construction and installation of capital assets.
- **Step 3: Documented and reviewed regulatory and accounting policy guidance**. In this step, KPMG researched the guidance provided by various accounting and regulatory authorities on the topic of overhead capitalization. The objective of this step was to ensure that the approach adopted in FEI's capital overhead cost allocation methodology was consistent with U.S. GAAP. This step also examined a summary of differences between IFRS and U.S. GAAP in this area. A summary of the sources of our research is provided in Appendix C.
- **Step 4: Assessed the reasonableness of FEI's capital overhead cost allocation methodology.** In this step, we assessed the alignment between FEI's methodology against external guidance from regulators and the practices of other Canadian utilities as observed through a review of regulatory filings in various jurisdictions. This included a review of the methodology utilized in the survey-based model against FEI's internal policy and internally generated criteria developed to provide an appropriate cost allocation methodology.
- **Step 5: Assessed the reasonableness of the overhead activities allocated to capital.** In this step we assessed the reasonability of the overhead activities allocated to capital against internal policy and external guidance.
- **Step 6: Assessed the reasonableness of the drivers used to allocate overhead costs to capital.** In this step we assessed the reasonability of drivers used in the overhead activities allocated to capital against internal policy, external guidance from regulators and the

practices of other Canadian and U.S. utilities as observed through a review of regulatory filings in various jurisdictions.

- **Step 7: Data Validation of Capital Overhead Capitalization Model**.
  - Reviewed the overhead capitalization model for formula accuracy;
  - Validated costs used in the capital overhead cost allocation methodology against the 2013 budget;
  - Validated cost drivers against supporting system records or other corroborative evidence; and
  - Validated the selection by management to source data of US and Canadian utilities whose publicly available information on capitalization rates is included in Appendix A.
- **Step 8: Assessed the reasonableness of the resulting overhead capitalization rate.** In this step we assessed the reasonability of the resulting overhead capitalization rate. The following steps were undertaken:
  - Comparison of the results of the Survey Model against the Mathematical Model;
  - Compared with the results of the previous study. The results of the current interviews were also compared to the results of interviews undertaken in 2009 by the Company and presented in a KPMG report and filed with the BCUC as part of the Company's 2010- 2011 RRA, prepared under IFRS; and
  - Comparison against other Canadian and U.S. utilities as observed through a review of regulatory filings in various jurisdictions.

6. FEI Overhead Capitalization Methodology and Results

In this section we summarize the methodology and approach used to complete the study. Our work plan was developed in collaboration with FEI management and was designed to provide a supportable basis for the Company's overhead capitalization methodology.

FEI has examined two methodologies to determine the capital overhead rate – the "Survey Model" (based on inquiries and other supplemental information with business units) and the "Mathematical Model".

6.1 Capital Overhead Cost Methodology

The following methodology was applied to determine the capital overhead capitalization rate by the Company:

6.1.1: Develop and document criteria for capital cost allocation based on guiding principles.

Management developed guiding principles for the capital cost allocation methodology and applied the following commonly used cost driver assessment principles when evaluating which cost driver should be used to allocate a cost.

	Internal FEI Criteria	Detail
1	**Cost Causality**	The identified driver, being it work effort or investment, has a direct correlation to the cost of the services or goods and also has a direct effect on the level of service for that capital project.
2	**Objective Results**	The use of the allocation driver results in an objective allocation amount that is free from undue bias.
3	**Cost Effectiveness**	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
4	**Stability Over Time**	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.
5	**Transparent and Supportable Methodology**	The driver used and the source or basis on how it is determined is visible to all parties affected.The allocation approach is supported by a defined and documented methodology, model and other supporting documentation.
6	**Regulatory Precedence**	The cost allocation methodology has been tested and approved through previous regulatory reviews.
7	**Distinguishable from Directly Allocated Capital Costs**	The overhead costs must be distinguished from those that are directly charged to capital.
8	**Accuracy of Underlying Data**	Any data used in the methodology should be

		accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output.
9	**Flexibility/Adaptability**	The methodology should be able to accommodate future changes in regulatory, accounting and organizational changes with reasonable ease.

6.1.2: Survey Model – Create a company questionnaire and interview company officials. In this step, management created a questionnaire so as to best understand the activities and potential cost drivers across the selected and relevant corporate functions and business units. A copy of this questionnaire is provided in Appendix B.

Management then used the questionnaire to interview senior representatives from each department to understand and identify those activities that appear to support, either directly or indirectly, capital projects at FEI. The departments are summarized in Table 1 in Section 6.2.1.

The purpose of this step was to better understand departmental involvement in capital work and the costs attributable to capital work that have not been charged directly to capital. As part of this step:

- A written description of the specific activities within the department that support capital projects was completed; and
- Estimates of the percentage of the budgeted cost of activities that should be allocated to capitalized overhead were obtained.

6.1.3: Survey Model - Compilation of data. Management compiled the results of the interviews into a summary model in order to determine an approximate overhead capitalization rate. See the results per Table 1.

6.1.4: Survey Model - Comparison with previous interviews results. The results of the current interviews were also compared to the results of interviews undertaken in 2009 by the Company and presented in a KPMG report and filed with the BCUC as part of the Company's 2010-2011 RRA. See results per Table 4.

6.1.5: Mathematical Model. FEI detailed and documented the basis for the mathematical capitalization methodology. Management then calculated the Mathematical Model using the 2013 budget. The methodology and results of the update are discussed in Section 6.3 below.

6.1.6: Comparison of Mathematical Model results against those obtained from the Survey Model. Management reviewed the estimates received from the Survey-based Model against the Mathematical Model. The basis for the comparison is that management believes the estimates from both approaches allow a context for the BCUC to better understand the range of possible capitalization percentages that exist within the interpretations required under the accounting standards. The comparison between the Survey-based Model and the Mathematical Model is shown in Section 6.4.

6.1.7: Documented regulatory and accounting guidance. The Company researched and provided references to a variety of U.S. accounting guidance on the capitalization of overhead costs. See Section 4.

6.1.8: Surveyed U.S. and Canadian Utilities. The Company researched from publicly available information a sample of both U.S. and Canadian utilities with regard to the overhead capitalization methods. The research was undertaken to bring a context of overhead costs noted by other utilities to be capitalized and the capitalization rates employed. The results of the survey are provided in Appendix A.

6.2 Explanation and Results of Survey Methodology

Under the Survey Model, the Company interviewed department heads and senior managers within the corporate functions and business units listed in Table 1. Management sought to understand and identify those company departments that support, either directly or indirectly, capital projects at FEI.

The purpose of this step was to gain an understanding of the specific activities within FEI that may be eligible to have costs allocated to capitalized activities. This step also provided KPMG with a good understanding of FEI's organizational structure and its approach to the acquisition, construction and installation of capital assets. The details of the survey questions used in this approach are provided in Appendix B.

Under the Survey Model, the overhead capitalization rate is determined based on the residual amount of operating business unit and corporate function costs that support capital activities, which have not been allocated to specific capital related activities. That is, this residual is the O&M costs after direct charges performed by departments have been made to capital projects. The assessment is based on labour and non-labour expenses separately for each department. Labour costs are allocated to capital based on a labour time estimate and non-labour costs are allocated based on estimated costs which are related to capital. This determines the overhead capitalization rate. The process is illustrated as follows:

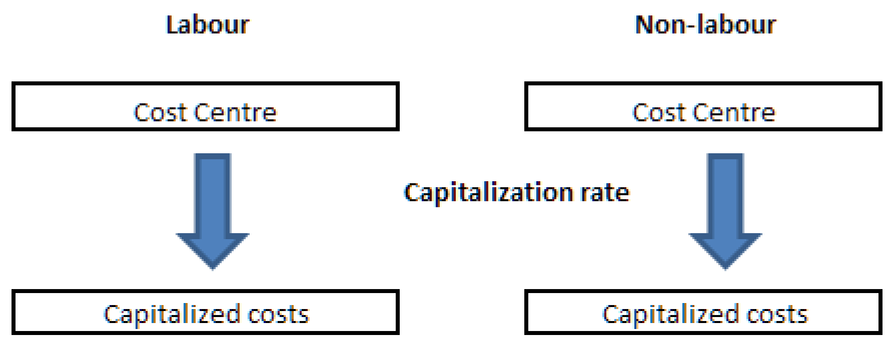

Diagram 1: Survey Model illustration

The overall overhead capitalization rate which is determined therefore reflects both labour and non-labour components. The rate is expressed as a percentage of O&M after direct capital charges and does not reflect the percentage of O&M costs which have been charged to capital through direct methods.

6.2.1 Survey Model Results

The results of this methodology suggested an overhead capitalization rate of approximately **12 percent**. Table 1 below shows the build-up of this rate for the FEI departments. As can be seen in Table 1, the majority of the capital related dollars is determined by Operations, Information Technology and Operations Support.

Table 1: Results of Survey Model (2013)

Department	Total Cost ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	63,189	11,008	17.4%
Customer Services	52,452	-	0.0%
Energy Solutions & External Relations	18,181	321	1.8%
Energy Supply & Resource Development	3,738	616	16.5%
Information Technology	25,379	7,131	28.1%
Engineering Services and PM	16,956	1,669	9.8%
Operations Support	12,990	2,953	22.7%
Facilities	9,259	121	1.3%
Environment, Health & Safety	2,999	750	25.0%
Finance & Regulatory Services	14,184	827	5.8%
Human Resources	8,511	1,414	16.6%
Governance	7,935	266	3.4%
Corporate	230	11	4.5%
Totals	**236,003**	**27,086**	**11.5%**

6.3 Explanation and Results of Mathematical Model Methodology

FEI has also employed a Mathematical Model to determine the level of overhead to be capitalized. The estimate of the overhead capitalization rate is developed through a two-step process. As in the Survey Model it should be noted that corporate overheads are allocated after the direct charges to capital projects. The process is illustrated as follows:

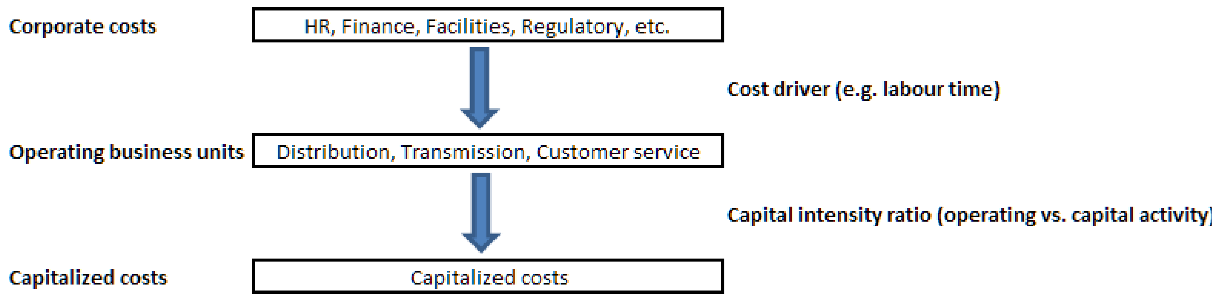

Diagram 2: Mathematical Model illustration

The details of the two-step process are as follows:

Step A: 100% allocation of corporate costs into the three FEI operating business units

The various corporate functions of the Company are allocated to the three operating business units which they support (Distribution, Transmission and Customer Service). In effect there is a 100% allocation of all corporate support costs into the three operating business units.

A series of cost drivers are determined for this 100% allocation based on;

- Employee count - budgeted number of Distribution, Transmission and Customer Service employee count in 2013;
- Total corporate services expenditures - total expenditure on O&M and capital
- Relative effort - representing approximate time spent supporting each business unit and;

The departmental costs are allocated to the operating business units based on the corporate support allocations determined above.

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 $8.5 million are allocated 61.5 percent (564 of 918 employees) or $5.2 million to Distribution, 6.5 percent or $0.6 million to Transmission and 32 percent or $2.7 million to Customer Service.

Step B: Capitalize costs from the three business units into capital projects

Having fully absorbed the costs of corporate functions into the three operating business units of Distribution, Transmission and Customer Service, the relative proportions of capital-related work (capital intensity) for 2013 in those corporate costs within the operating business units are determined. This is based on the relative labour budgeted to be charged to O&M expense versus capital in 2013 – the "*capital intensity ratio*".

A key difference between the survey-based and mathematical model is that, in the mathematical model, remaining business unit costs (after the direct charges to capital projects in Distribution, Transmission and Customer Service), undergo no further allocation to capital activities. This is not the case in the survey-based approach whereby the business units and the corporate costs are reviewed for allocation to capital. For example, in the mathematical model there are no costs related to capital activity not directly charged to capital projects for Distribution, which makes up some $11.0 million of the Operations capital related charge in the survey-based approach per Table 1.

6.3.1 Mathematical Model Results

The results of this methodology suggested an overhead capitalization rate of approximately **11 percent**.

The corporate functions, their drivers and the resulting allocations between the business units for 2013 are summarized in Table 2 below.

Table 2: Determination of Corporate Support Levels by Operating Unit (2013)

		Percent Allocated to		
Department	**Driver**	**Distribution**	**Transmission**	**Customer Service**
Energy Solutions & External Relations	Labour Time Estimate	40.0%	10.0%	50.0%
Information Technology	Labour Time Estimate	54.8%	11.3%	33.9%
Facilities	Employee Count	61.5%	6.5%	32.0%
Environment, Health & Safety	Employee Count	61.5%	6.5%	32.0%
Finance & Regulatory	Total Expenditure ($)	58.1%	15.9%	26.0%
Human Resources	Employee Count	61.5%	6.5%	32.0%
Property Services	Employee Count	61.5%	6.5%	32.0%
Governance	Total Expenditure ($)	58.1%	15.9%	26.0%
Corporate	Total Expenditure ($)	58.1%	15.9%	26.0%

The capital intensities of the operating business units are: 46 percent for Distribution, 20 percent for Transmission, and 3 percent for Customer Service. For example, of the $5.2 million of Human Resources costs representing support to Distribution, 46 percent or $2.4 million would relate to capital work. In total, of the $8.5 million of O&M Expense for Human Resources, $2.6 million is forecast to be allocated by way of capitalized overhead for Distribution, Transmission and Customer Service.

The application of the capital intensity ratios are applied against the costs of each department to determine the overhead capitalized. This is shown in Table 3, which shows the build up of the overhead capitalization rate for the corporate departments and the business units. The total overhead which is capitalized in this model is $24.8 million. There is no specific capitalization rate by individual corporate function under this model as all costs are first allocated to the business units.

Table 3: Application of Unit Factors to Calculate Capitalized Overhead (2013)

Capital Intensity ratio	46.0%	20.0%	3.0%			
	$000 Allocated to					
Department	Distribution ($000s)	Transmission ($000s)	Customer Service ($000s)	Capital Related ($000s)	Total Cost ($000s)	Capitalization Rate (%)
Energy Solutions & External Relations	3,345	364	273	3,982	18,181	21.9%
Information Technology	6,402	573	258	7,233	25,379	28.5%
Facilities	2,619	121	89	2,829	9,259	30.6%
Environment, Health & Safety	848	39	29	916	2,999	30.6%
Finance & Regulatory	3,790	452	110	4,353	14,184	30.7%
Property Services	401	19	14	433	1,418	30.6%
Human Resources	2,407	111	82	2,600	8,511	30.6%
Governance	2,120	253	62	2,435	7,935	30.7%
Corporate	61	7	2	70	230	30.7%
Operations					63,189	
Customer Service					52,452	
Energy Supply & Resource Development					3,738	
Engineering Services & PM					16,956	
Operations Support					11,572	
TOTALS	**$ 21,995**	**$ 1,940**	**$ 917**	**$ 24,852**	**$ 236,003**	**10.5%**

6.4 Evaluation of Results between Models and with Prior Study

The table below provides a comparison of the results of the Mathematical Model and Survey Model against the previous studies which have been undertaken for the Company.

Table 4: Comparison between Models and to prior study

Current study		Previous study	
Survey Model	Mathematical Model	2010/2011 KPMG Study[4]	Previously Approved Rate by BCUC 2010-2013
12 %	11%	8 %	14%

The results of both models provide a similar overall estimate of the overhead capitalization rate, even though the methodologies used and results obtained are quite different at the departmental level. The 2010/2011 survey-based KPMG Study was conducted under IFRS and at a different point in time and hence does not represent a directly comparable study. The capitalization rates under both models for the purpose of the current study have been found to be lower than the approved BCUC rate for 2010 – 2013.

The assessment of the two models provides a context for the BCUC to better understand the range of possible capitalization percentages that exist within the interpretations required under the accounting standards. However, KPMG finds the Survey Model provides a more transparent linkage of the unallocated overhead costs related to capital activities and therefore believes that the most appropriate capitalization rate is approximately 12 percent.

6.5 Utility Industry - Capitalized Overhead Rate Comparisons

There are a number of principle challenges with the comparison of the capitalization rates noted above and those applied in the utility industry. First, there is a significant level of variation in individual utility entities. These entities may be involved in nuclear power, hydroelectric, gas or a mix thereof. These entities may be of varying size and be at differing stages in capital and infrastructure development and investment. Second, there is no standard means of reporting or recording of the capital overhead rate across utility entities. Differences in organizational structures, differences in accounting and other policies (including capitalization policies) will all impact the capitalized overhead rate. Third, the available information can only be interpreted from publicly available regulatory filings. These filings may not be consistent in how they define and present capital overhead rates.

Given these limitations, the FEI survey, which is noted in Appendix A, reviewed overhead capitalization practices and policies of fifteen regulated US and Canadian utilities (4 U.S. companies and 11 Canadian). The United States utilities operate in compliance with FERC guidelines and are governed by U.S. GAAP. In recent years a number of Canadian utilities for various reasons have sought and have been granted permission by the respective regulators to

[4] Prepared in accordance with International Financial Reporting Standards.

adopt U.S. GAAP. Of the eleven Canadian companies included in the survey eight have adopted U.S. GAAP.

The survey's main findings regarding utility overhead capitalization in Canada and the United States are:

- Among the utilities surveyed both in Canada and the United States, there is no single or common methodology for allocating indirect costs to capital.

- Utilities mostly use direct allocation, cost drivers and time (effort) studies for the capitalization of indirect costs.

- The composite capitalization rates range between 4% and 60% of O&M costs.

- A study by Black and Veatch done for Hydro One in 2012 of selected utilities concluded that overhead capitalization rates (as a percentage of O&M) in the US ranges ranged from 7.33% to <50% with a median of 19%[5].

[5] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20C/C1-07-02.pdf

7. KPMG Evaluation

7.1 Overview of Evaluation Conducted

KPMG finds the FEI survey-based capital cost allocation methodology, as detailed in Section 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities that have not been directly charged to capital projects (i.e. overhead capitalization) as examined in the evaluation criteria discussed below. This methodology is consistent with FEI's internally generated evaluation criteria and available accounting guidance.

KPMG's approach is detailed in the steps noted per Section 5 of this report. Steps 1 and 2 of the KPMG approach address the gathering of data in order to perform assessment in Steps 4 through 9 found below.

In Step 2 of our approach, a sample of business group interviews were attended by KPMG to gain an understanding of the specific activities and allocation bases (cost drivers) within FEI that may be related to or directly attributable to capital. Section 7.5 of this report details KPMG's review coverage of FEI's O&M costs assessed as eligible for capitalization. This was based on attendance at select FEI business group survey interviews and review of allocation calculations prepared by FEI.

Step 3 of KPMG's approach included a documentation of the guidance provided by various accounting and regulatory authorities. The result of this review is included in Section 4 to this report.

7.2 Evaluation of the Capital Overhead Allocation Methodology

An overhead capitalization methodology should address a number of evaluation criteria that support Company objectives. The Company developed a number of criteria in order to be able to evaluate the appropriateness and reasonableness of the capital overhead methodology which is described in Section 6 of this report.

7.2.1 Reasonability of the Evaluation Criteria Used to Assess FEI Cost Allocation Methodology

In Step 4 KPMG reviewed the internally generated Evaluation Criteria used by FEI to assess the cost allocation methodology. Table 5 provides a summary of these Evaluation Criteria principles that are consistent with Management's assessment principles as described in Section 6.

KPMG finds that the evaluation criteria used to evaluate the capital overhead cost allocation methodology to be appropriate in relation to the accounting guidance and the purpose of the current study.

7.2.2 Reasonability of a) the Survey Model and b) the Mathematical Model Methodologies against the internally generated Evaluation Criteria of FEI

In Step 4 KPMG also assessed FEI's capital cost allocation methodology against FEI's internal criteria as outlined in Section 6 of this Study. These assessment criteria are provided in the table below.

Table 5: Evaluation of Capital Overhead Allocation Methodology

		Assessment	
Evaluation Criteria	**Explanation**	**Mathematical Model**	**Survey model**
Cost Causality	The allocation driver has a direct correlation to the cost of service and has a direct effect on the level of service for that capital project.	✓	✓✓
Objectivity	The use of the allocation driver results in an objective allocation amount that is free from bias.	✓	✓
Cost-Effectiveness	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.	✓✓	✓✓
Stability over time	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.	✓	✓✓
Transparent and Supportable Methodology	The driver used and the source or basis on how it is determined is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model and other supporting documentation.	✓	✓
Regulatory Precedence	The cost allocation methodology has been tested and approved through previous regulatory reviews.	✓	✓✓
Distinguishable from Directly Allocated Capital Costs	Overhead costs allocated using this methodology are those that are not directly charged to capital and represent overhead activities.	✓	✓✓

		Assessment	
Evaluation Criteria	**Explanation**	**Mathematical Model**	**Survey model**
Accuracy of Underlying Data	Any data used in the methodology should be accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output.	✓✓	✓✓
Flexibility / Adaptability	The capitalized overhead cost allocation methodology and integrated Excel model facilitates updates, and thus supports the criteria	✓	✓
Key: ✓✓ = satisfies the evaluation criteria ✓ = somewhat satisfies the evaluation criteria ✕ = does not satisfy the evaluation criteria			

Though there are differences between the Survey Model and the Mathematical Model, KPMG finds the Survey Model provides a clearer linkage of the costs related to capital activities that have not been directly charged to capital projects. The examination of the two models provides a basis for the comparison between both approaches and allows a context for the BCUC to better understand the range of possible capitalization percentages that exist within the interpretations required under the accounting standards.

7.3 Qualitative Evaluation of Overhead Activities Allocated to Capital

In Step 5 of the KPMG approach, in order to ensure that the costs being allocated to capital are appropriate under U.S. GAAP, KPMG conducted a high level review of the overhead activities allocated to capital against internal policy and accounting guidance. The nature of the activities which are allocated to capital were informed through details of the functions of each department/business unit within the Company and through survey results and discussions. Costs for capital activities that have not been directly charged to capital projects can be categorized as follows:

i) Non-Project Specific Capital Support

This includes preliminary designing, evaluating, initiating, approvals and implementing capital additions.

This is captured in capital overhead because:

- It is impractical to capture cost directly to specific capital projects
- The activities involved relate to many capital projects rather than specific or identified ones

For example – capital project managers who supervise multiple projects.

ii) Direct Oversight of activities directly related to capital projects
These costs include the direct supervision, administration, cost control and reporting that are in direct support of capital projects.
For example – supervision of construction departments or project management activities not directly charged to each specific project.

iii) Corporate Support Functions and Infrastructure
This category includes Corporate Support Functions and Infrastructure that enable departments that are directly involved in performing capital work.
For example – Human Resources, Facilities, IT.

For the three business units (being Distribution and Transmission and Customer Service), overhead costs are allocated to capital as a result of the non-project specific and direct oversight costs within the Distribution and Transmission groups. No indirect overhead is capitalized in the Customer Service group as this group directly charges any applicable costs to capital.

Certain activities are difficult to directly relate to capital, including for example, Information Technology and Human Resources as they are removed from actually performing the capital work and represent support functions; however FEI has applied a methodology to identify where these support activities relate to capital projects.

KPMG finds that, given the very general guidance which is provided under U.S. GAAP, the nature of costs which are being allocated to capital is consistent with the available guidance, as discussed in Section 4.

7.4 Evaluation of Cost Drivers used to Allocate Costs to Capital

In Step 6 KPMG analyzed the nature of the drivers used by FEI to allocate costs to capital projects. The cost drivers under the Mathematical Model and the Survey Model are different and are evaluated separately below.

7.4.1 Survey model

Under the Survey Model, capitalized overhead is allocated to capital differently for labour and non-labour costs. The allocation is based on the following:

- **Labour Time Estimate**

  For the labour cost component of business operating units and corporate functions, the estimate of labour time incurred in capital asset development related activities was chosen as it most accurately reflects the key component of the overhead cost to be allocated. In developing this estimate, consideration was given to the level of activity reduction in the absence of capital development activities, after direct charges of capital overhead activities.

KPMG notes that the nature of the FEI survey was kept to a relatively high level (usually departmental head) in order to drive an estimate of the corporate function or business unit costs associated with capital activities that had not been directly charged to capital projects. Interviews were conducted with each of the corporate functions noted in section 7.5.

KPMG finds that, where estimated labour time was used to determine the allocation of the corporate functions and business unit costs to capital projects, the allocation basis applied is consistent with the internally generated Evaluation Criteria established by FEI.

- **Budgeted Cost Amount**

  For the non-labour cost component of business operating units and corporate functions (e.g. external consultants, equipment, software) the allocation estimation was performed based on management's estimate of the costs which have not been direct charged and are related to capital activities.

KPMG finds that, where management's estimate of the costs was used to determine the allocation of corporate function and business unit costs to capital projects, the allocation basis applied is consistent with the internally generated Evaluation Criteria established by FEI.

7.4.2 Mathematical Model

KPMG assessed the reasonability of the drivers used to allocate overhead costs to the business units. Under this model, the corporate costs after allocation to the business units are then capitalized based on the capital intensity ratio. The basis to allocate corporate costs to the business units are as follows:

- **Employee Count**

  The number of employees within the business units has been used as the basis for the allocation of the costs within the corporate functions to the business units of Distribution, Transmission and Customer Service. The number of employees within the business units is therefore seen to correlate most closely with the costs of these corporate functions.

KPMG finds that the management estimate of employee numbers is a reasonable driver to allocate indirect corporate overhead costs in relation to the internally generated Evaluation Criteria established by FEI

- **Total Expenditure**

  For certain corporate functions, the expenditure incurred by the business units and not the employees within these units has been used as the cost allocation basis. This is due to the cost of certain functions, such as the finance group, being a more appropriate cost driver due to the activities of that function.

KPMG finds that the management estimate of expenditure is a reasonable driver to allocate indirect corporate overhead costs to the business units in relation to the internally generated Evaluation Criteria established by FEI.

- **Labour time estimate**

FEI has determined that two specific corporate functions (IT and Energy Solutions and External Relations) should be allocated based on an estimate of the labour time involved in the support of the respective business units. In developing this estimate, consideration was given to the level of activity reduction in the absence of capital development activities, after direct charges of capital overhead activities.

KPMG finds that the management estimate of labour time is a reasonable driver to allocate indirect corporate overhead costs to the business units in relation to the internally generated Evaluation Criteria established by FEI.

7.5 Data Validation - Steps, Results and Limitations

In Step 7 of KPMG's approach, in order to be able to verify the data used in the study, KPMG assessed the methodology and values utilized in the Excel calculation model against the Company's proposed and documented capital cost allocation methodology policy. As previously noted this report, all figures which have been applied in both models relate to the 2013 budget.

KPMG performed the following procedures:

1. **Assessment of underlying cost population and cost resources**
   a. verified departmental labour and non-labour budget cost components and agreed to the 2013 budget figures;
   b. verified the total cost population against the 2013 budget to ensure completeness of departmental cost population; and
   c. re-performed the calculations prepared by management to check mathematical accuracy, including capitalization percentages calculated.

2. **Assessment of allocation bases (cost drivers)**
   In conjunction with understanding the allocation bases, KPMG traced the allocation bases to source calculations. As two models were used, the procedure differed slightly.
   a. For the Mathematical Model:
      i. We verified the full time equivalent staff numbers to the 2013 Revenue Requirements Application;
      ii. We verified total expenditures to the 2013 budget figures;
      iii. Agreed the budgeted hours used to calculate the capital intensity ratios to an SAP extract;
      iv. We re-performed the calculations prepared by management of the capital intensity ratios for Distribution, Transmission and Customer Service.
   b. For the Survey Model:
      i. We attended interview discussions with department managers where estimated labour cost time was determined. Specifically, we attended interviews related to departments which comprised approximately $25 million out of the $27 million of costs allocated to capital;

ii. Additional specific procedures were conducted for departments in order to be able to verify costs, such as agreement to departmental budgets; agreement to department role allocations. The following specific procedures were conducted for the following departments which in total approximate 64% of allocated capital costs:

Operations. This business group's charges to capital are related to non-project specific and to direct oversight activities. For the labour time component which has been allocated to capital, KPMG reviewed the department structure within the Distribution, Transmission and Plant Operations departments and discussed with management the nature of the roles of individuals who were not being directly charged to capital project activities. The Operations group overhead capitalization rate was determined based on a build up, following the review of the function and role of sixty-six sub-groups. KPMG reviewed this subdivision and discussed the nature of costs within with management.

Information technology. This corporate support function provides information technology infrastructure to support capital programs. Examples of such costs include those related to specific I.T. related applications; specific IT related support provided to capital groups which provide the necessary tools for project delivery.

The principle drivers of the costs within the I.T. group are related to the complexity and volume of applications and to the number of users for each type of software. This is similar to the non-labour component, which is more significant than the labour component allocated to capital overhead in this group. The non-labour cost is driven by user licenses, and the number of users and the application requirements impacts network and storage capacity. Hence, the number of user licences and how these are split between operating and capital functions is reflective of the costs being driven within the group and this was compared to the estimated labour and non-labour costs estimates.

3. Other regulatory filings

An external survey was conducted by FEI management to determine the applied overhead capitalization rates across the United States and Canada. This survey is provided in Appendix A of this report. KPMG agreed to source the information supplied by management per Appendix A relating to the regulatory filings in U.S. and other Canadian utilities.

FEI management reviewed a total of 15 organizations that have issued publicly available information on their level of capitalized overhead. Of these 15 utilities, 11 are Canadian based and 4 are U.S. based.

Several factors should be taken into consideration when comparing the rates to FEI including:

- the financial reporting framework,
- the volume of capital activities and size of those entities,
- whether the entities are in gas distribution, hydro generation, nuclear, coal or other forms of power production, and
- the capital overhead cost allocation methodology in use.

The results of the survey show that there is a significant level of variation in the capitalized rates across the utilities industry in North America. A summary of the rates noted in Canada for certain utility entities which are applying U.S. GAAP is as follows:

Table 6: Comparison to industry findings

Utility	Jurisdiction	Accounting Framework	Overhead Rate
AltaGas	Alberta	U.S. GAAP	16%
Hydro One Networks Inc.	Ontario	U.S. GAAP	9%
Union Gas	Ontario	U.S. GAAP	15%
Enbridge Gas	New Brunswick	U.S. GAAP	44.8%
Enbridge Gas	Ontario	U.S. GAAP	19.8%
Heritage Gas	Nova Scotia	U.S. GAAP	59.2%[6]
Pacific Northern Gas	British Columbia	U.S. GAAP	4%

Due to the variability in the nature and size of comparable organizations, it is difficult to generalize the comparability of the rates to that of FEI. It is noted that the rates for FEI noted in this report would be within the range noted in industry, though it is clear the industry does contain a wide range of results.

KPMG finds the results of the data validation procedures performed did not note any significant errors with the capitalization rate as stated by FEI. However, these procedures performed do not constitute an audit of the capitalization cost allocation methodology or allocated capitalization percentage of O&M costs.

[6] 2010 actual

7.6 Assessment of the resulting overhead capitalization rate

In Step 8 KPMG assessed the methodology and resulting values utilized in the Survey-based model against FEI's proposed capital cost allocation methodology.

As described in Section 7.5 of this report, certain procedures were conducted to assess the accuracy of FEI's underlying 2013 budgeted costs and allocation bases used to calculate the allocation of costs to capital within the model.

KPMG finds the FEI Survey-based model and underlying costs used in the model to be consistent with the cost allocation methodologies as proposed by FEI and guidance related to U.S. GAAP. Based on the results of the Survey Model, the estimated overhead capitalization rate is approximately 12 percent.

Appendices

Appendix A - External Survey

i. Introduction

This appendix describes how a number of regulated Canadian and United States utilities capitalize overhead costs and the applicable capitalization rates. The selected Canadian utilities have either adopted U.S. GAAP or IFRS. Several utilities were surveyed by investigating their publicly available regulatory information and other public documents but only those utilities with available information that was useful for the overhead capitalization analysis are included in this appendix.

ii. Executive Summary

The Company reviewed overhead capitalization practices and policies of 15 regulated U.S. and Canadian utilities (4 U.S. companies and 11 Canadian). The United States utilities operate in compliance with FERC guidelines which are contained in the FERC Uniform System of Accounts (USoA) and are governed by U.S. GAAP. In recent years a number of Canadian utilities have sought and have been granted permission by the respective regulators to adopt US GAAP. Of the 11 Canadian companies included in the survey 8 have adopted U.S. GAAP. In some cases it was difficult to determine the overhead capitalization rates as percentage of O&M costs because the rates were not provided and the financial information necessary to calculate the rates was not available. Where applicable, capitalized overheads were added back to calculate the capitalization rate as a percentage of O&M costs.

The survey's main findings regarding utility overhead capitalization in U.S. and Canada are:

- Among the utilities surveyed both in United States and Canada there is no single or common methodology for allocating indirect costs to capital.

- Utilities mostly use direct allocation, cost drivers and time (effort) studies for capitalization of indirect costs, which is a similar approach to the survey-based model.

- The capitalization rates range between 4% and 60% of O&M costs.

- A study of 18 Canadian and US utilities by Black and Veatch for Hydro One concluded that capitalization rates in Canada and the U.S. had an observed median of 19% and the range of overhead capitalization rates varied from 5% to greater than 50%.

This following table summarizes the findings of FEI's survey of utility companies.

Canadian Utilities				
Utility	**Accounting Standard**	**Overhead Cost Elements**	**Capitalization Rate**	**Reference**
AltaGas Alberta	Adopted US GAAP effective January 1, 2012	Salaries, employee benefits, vehicle Contractor Expense, Travel Expenses, Rent, Maintenance Contracts, Office Expenses, Communications, Training, Bad Debt, Insurance, Audit, Legal , Consultant and Other Fees, Regulatory Costs, Material, Contractor & Other Shared Costs.	Capitalized Overhead of $7M is approximately 16.0% of 2012 Forecast O&M	http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-091.pdf
Hydro One Networks Inc. Ontario	Adopted US GAAP effective January 1, 2012	Corporate Functions and services, Asset Management and Operations (Asset management comprises of Asset Strategy, Business Performance, Strategy Alignment, Sustainment Investment, Distribution Business Development, Asset Management VP Office, and Transmission Development).	A Transmission Overhead Capitalization Rate of 9% for 2013 and 2014	Black and Veatch report http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20C/C1-07-02.pdf.
Union Gas Ontario	Adopted US GAAP effective January 1, 2012	Executive, Finance, Information Technology, Human Resources, Communications, Law, Strategy Management, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement.	2007 Board-approved level of 15.0%.	http://www.uniongas.com/aboutus/regulatory/EB-2011-0210%20-%202013%20Rebasing/UNION_Exhibit%20D_Updated_20120327.pdf
Enbridge Gas New Brunswick	Adopted US GAAP effective January 1, 2012	Sales, Marketing, Installations, Attachments, Logistics, Construction & Maintenance, Planning & Tech, Service, Eng QA, Customer Care, Incentives, IT, Financial reporting, Corporate Administration and HR.	Various rates ranging from 8.7% to 82% resulting in a total of 44.8% of O&M	http://naturalgasnb.com/CMS/site/media/naturalgasnb/Schedule%2010%20-%20Capilization%20of%20OM%20Expenses%20Report.pdf
Enbridge Gas Ontario	Adopted US GAAP effective January 1, 2012	Finance, Risk management, customer care, Energy supply, Benefits, IT, Legal, Business development, Pipeline Integrity, HR, Public and government affairs.	19.8% of O&M costs after adding back capitalized costs	http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/357954/view/EGDI_APPL_D1-3-1_Updated_20120803.PDF
Newfoundland Power	Adopted US GAAP effective	Operating, Supervision and Miscellaneous; Tools, Equipment, Safety Clothing and	6.8% of gross O&M based on the 2013 Forecast.	http://www.pub.nf.ca/applications/NP2012Capital/files/app

Canadian Utilities				
Utility	**Accounting Standard**	**Overhead Cost Elements**	**Capitalization Rate**	**Reference**
	January 1, 2012	Uniforms; Accounting; Printing and Stationery; Employees' Welfare; HR Planning and Administration; Human Resource Services; and Company Pension Plan.		lic/NP2012Application-CapPlan.pdf
Heritage Gas Nova Scotia	Adopted US GAAP effective January 1, 2012	Salaries and related expenses, Telecommunications (land lines and cell phones), Equipment direct (expenditures pertaining to work equipment used, Information technology, Insurance; Office supplies, Professional and consulting fees, Rent, Travel, Utilities, Vehicles and other administration.	Percentage of O&M **Actual** 2009 = 58.8% 2010 = 59.2% **Estimated** 2011 = 56% 2012 =50.3 % 2013 = 46.8% 2014 = 43.8%	http://www.heritagegas.com/documents/pdf/001%20GTA%20Version%2011_law.pdf
Pacific Northern Gas British Columbia	Adopted US GAAP effective January 1, 2012	Field Operations (operations and Administration), Corporate (administration), Benefits on direct labor, Warehouse and Shop Expense, and Equipment Operating Expense.	4% of O&M costs for 2012	http://www.bcuc.com/Documents/Proceedings/2010/DOC_26525_B-1_PNG-West_2011_Revenue_Requirements_Application.pdf
Manitoba Hydro	Adopting IFRS effective 2013/2014		17 % of total O&M costs effective 2010/2011	http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/appendix_5.6.pdf
ENMAX Power Corporation Alberta	Adopted IFRS effective January 1,2013	Information Technology, Human Resources, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and Genera Engineering, Fleet and Procurement.	19% administrative overhead capitalization rate pre IFRS, approximately 7.4% under IFRS.	http://www.auc.ab.ca/applications/decisions/Decisions/2009/2009-035.pdf http://www.auc.ab.ca/applications/decisions/Decisions/2012/2012-246.pdf
Northwest Territories Power Corporation	Adopting IFRS effective April 1, 2013	Overhead and administrative costs including pension and other post-retirement benefits.	Capitalization rate increased from 10% to 18%	http://www.assembly.gov.nt.ca/_live/documents/content/12-06-06TD20-17(3).pdf

United States Utilities

The United States utilities operate in compliance with FERC guidelines which are contained in the FERC Uniform System of Accounts (USoA) and are report under U.S. GAAP. According to the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act the relevant sections for the overhead capitalization are[7]:

Overhead Construction Costs

- All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.
- As far as practicable, the determination of payroll charges included in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.
- For major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.
- Engineering and supervision - This includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.
- General administration - This includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.
- Engineering services – This includes the amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

The US utilities determine which expenditures should be capitalized based on causality and benefit assessment. Utilities mostly use direct allocation, cost drivers and time studies to capitalize costs. Costs that are directly related to construction such as those mentioned above are allocated to capital. The capitalization of overhead costs that are not directly related to capital projects (administration and general costs) for each company is described below.

[7] US Code of Federal Regulations Electric. Uniform System of accounts prescribed for public on http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

United States Utilities

Utility	Overhead Cost Components	Capitalization Rates	Reference
Pacific Gas and Electric Company California	Corporate services department A&G salaries, material and supplies costs. This includes Corporate Affairs, Finance, HR, Risk and Audit, General Counsel, Chairman's Office, Regulatory and company president. Companywide A&G costs- Remaining vacation, workers compensation, benefits, short term incentives, and third party claims.	In the 2014 General rate case several rates were used ranging from 10.08% to 39.91%. Only rates for Labor A&G salaries and materials supplies are below 21%	Pacific Gas and Electric Company 2014 General Rate Case , Prepared Testimony, Exhibit (PG&E-9), Administrative and General Expenses https://www.pge.com/regulation/GRC2014-Ph-I/Testimony/PGE/2012/GRC2014-Ph-I_Test_PGE_20121115_254331.pdf
San Diego Gas and Electric (SDG&E) California	Labor Overheads, Administration and General Costs, Warehousing, Purchasing, Fleet, Shop, Exempt Material and Small tools.	Various rates for the 2010 - 2012 General rate case ranging from 18.7% to 91%. Labor cost rate is at 33.9%	2010-2012 GRC http://www.sdge.com/sites/default/files/regulatory/Exhibit%20SDG%26E-43R%20R_Agarwal_SDGE-R_Testimony_(Seg__%26_Reassgn).pdf
Southern California Gas (SCG) California	Labor Overheads, Administration and general costs, Warehousing, Purchasing, Fleet, Shop, Exempt Material, Small tools and Pipe fittings.	Various rates are used. In the 2010-2012 Rate Case the rates ranged from 12.9% to 78.2%	http://www.socalgas.com/regulatory/documents/a-10-12-006/Testimony/Exh%20SCG-36%20R_Agarwal_Re-Assignment_Rates.pdf
Kansas City Power and Light Company Missouri	Executive management and administrative labor costs. Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law and Treasurer. These costs cannot be directly allocated to production, transmission and distribution operations.	Commission determined labour rate to be to 21.41%.	http://www.kcpl.com/about/ratecase/MPSC_Bolin_080806.pdf

Appendix B – Capitalized overhead survey

The following questions were asked of senior management for the survey methodology.

1. Please provide a brief overview of the activities for each of the cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.

2. If your cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross cost centre budget before the direct charges to capital. E.g. If the Cost Centre total budget was $100, and direct charges to capital were $20 then the percentage would be 20/100 or 20%.

3. What percentage of Labour do you forecast will be directly charged to capital for 2013, 2014 and 2015? If there is an expectation that the amount of direct charge will be changing over time, please provide a brief explanation for the change.

4. Please describe the capital activities that are not directly charged to capital (and thereby should be captured in the capitalized overhead charge). We are looking to understand the nature of the work that you would attribute to capital activities.

5. Would the cost center operate with fewer staff if the company ceased to undertake all capital projects? If so – how many? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your cost centre staffing be impacted?

6. Of the amounts in each cost centre not directly charged to capital projects please differentiate labour and services activities between the following: capital, maintenance, administration and other.

Gas	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Electric	Capital	Operating and Maintenance	Administration
Labour			
Non-Labour			
Notes:			

7. What percentage of labour do you forecast will be spent on overhead capital activities (not directly charged to capital) for 2013, 2014 and 2015? If there is an expectation that the overhead activities will be changing over time, please provide a brief explanation for the change.

8. Please describe the primary driver that was used to estimate the percentage of labour forecast to be spent on overhead capital activities not directly charged to capital (for example management estimates, direct hours charged by staff between capital versus maintenance, customer activity etc). What is the driver that best correlates to the capital activities? Is it a direct or an indirect correlation? i.e. Does the indirect support change with the number of customers, employees, or some other driver?

9. Please indicate why these overhead capital activities are not charged directly to capital.

The 2013 BCUC approved O&M departmental budgets were then separated between labour and non-labour costs and the survey results were applied to determine an overall overhead capitalization rate.

Appendix C – Detailed listing of Accounting Guidance

U.S. GAAP references:

- ASC 360 *Property, Plant and Equipment*
- ASC 720 *Other expenses*
- ASC 970 *Real Estate*
- ASC 980 *Regulated Operations*
- Statement of Position, *Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment* Financial Reporting Executive Committee of the AICPA proposed standard, not adopted.

IFRS references:

- IAS 1 *Presentation of Financial Statements*
- IAS 16 *Property, Plant and Equipment*

Other sources:

- BCUC *Uniform System of Accounts Prescribed for Gas Utilities*
- FERC *Uniform System of Accounts*

Appendix F4

RATE BASE DEFERRALS

FEI Existing Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Margin Related	Commodity Cost Reconciliation Account (CCRA)	G-25-04; L-5-01; L-40-11	Captures the costs incurred by FEI to purchase its portion of the baseload commodity supply under the Essential Services Model and the commodity recovery revenues received from sales customers choosing to remain on the utility standard rate offering. Commodity price-related variances collected in the CCRA are taken into account when determining future commodity rate changes. The commodity rate is reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold, and the $/GJ value of the calculated rate change exceeds the minimum rate change threshold of $0.50/GJ.	12 months from Quarter-end
Margin Related	Midstream Cost Reconciliation Account (MCRA)	G-25-04; L-5-01; L-40-11	Captures the costs FEI incurs in performing the midstream function and the revenues collected through midstream rates. Gas Supply, in its midstream role, uses the pipeline and storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plans to manage load variability. The MCRA accumulates any resultant cost variances, including any volume-related variances due to differences between the forecast and actual consumption. The resulting variances are taken into account when determining future midstream rates. In addition, price and volume variances between the forecast and actual amount of company use gas are booked against and managed through the MCRA.	2 years proposed; see Section D3
Margin Related	Revenue Stabilization Adjustment Mechanism (RSAM)	G-59-94	Stabilizes the Company's delivery margin revenue from the Residential and Commercial customer classes. The RSAM enables FEI to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to what customers would have paid based on forecast use. If actual use is less than forecast, the RSAM deferral account is charged for the variance in use times the delivery rate and the RSAM revenue is credited. Conversely, if actual use is greater than forecast, the RSAM deferral account is credited and the RSAM revenue is decreased.	2 years proposed; see Section D3
Margin Related	Interest on CCRA, MCRA, RSAM and Gas in Storage	G-7-03; G-141-09	Variances from the forecast CCRA, MCRA, RSAM and Gas In Storage balances attract interest at the Company's short-term borrowing rate. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers.	Same as respective margin accounts; see Section D3
Margin Related	Revelstoke Propane Cost Deferral Account	G-72-90; L-40-11	captures the difference between the actual cost of propane and the amount recovered in rates, based on the approved reference price of propane. The propane reference price is reviewed on a quarterly basis, and typically reset when the propane recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold and the $/GJ value of the calculated rate change exceeds the minimum rate change threshold of $0.50/GJ.	12 months from Quarter-end
Margin Related	SCP Mitigation Revenues Variance Account	G-124-00; G-70-10	Captures any variation from the SCP revenues forecast and included in the determination of rates each year, and actual revenues received. Also captured the $2 million of Stage 1 KORP preliminary feasibility assessment costs.	3 years
Energy Policy	Energy Efficiency and Conservation (EEC)	G-36-09; G-44-12	Captures up to $15 million annually in new expenditures on EEC activities. See Section D3 for a further discussion.	10 years
Energy Policy	NGV Conversion Grants	G-98-99	Captures amounts awarded by FEI for NGV conversions for Rate Schedule 6 light duty customers.	5 years

FEI Existing Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Energy Policy	Compliance with Emissions Regulations	G-44-12	Captures potential compliance costs and revenues collected from credits related to Emissions Regulations, particularly the Emissions Trading Regulation and the Renewable and Low Carbon Fuel Requirements Regulation (“RLCFRR”) which are aimed to reduce Greenhouse Gas (“GHG”) emissions in BC. See Section D3 for further discussion.	n/a
Energy Policy	Biomethane Program Costs	G-194-10	Captured the biomethane costs applicable to all customers incurred prior to January 1, 2012. In addition, FEI is requesting approval to capture the application costs related to the FEI Biomethane Post Implementation Report and Application for Continuance of Biomethane Program in this account. See Section D3 for further discussion.	3 years
Energy Policy	On-bill Financing Pilot Program	G-163-12	Captures the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries.	10 years proposed. See Section D3
Energy Policy	NGT Incentives	G-161-12; G-67-13	Captures all grants and costs, including a portion of application costs, related to Prescribed Undertaking 1 of the GGRR.	Ten years
Energy Policy	Fuelling Stations	G-161-12	Captures the total revenue surplus or deficiency pertaining to fueling station facility costs that have not been forecast in rates, as well as the administration and application costs.	3 years
Non-controllable	Property Tax	G-51-03	Captures the variance between actual property taxes and the amount forecast in rates.	3 years
Non-controllable	Insurance	G-51-03	Captures the variance between actual insurance expense and the amount forecast in rates. See Section D3 for further discussion.	1 year
Non-controllable	Pension and OPEB	G-51-03	Captures the variance between actual pension and OPEB expense and the amount forecast in rates.	EARSL proposed. See Section D3
Non-controllable	BCUC Levies	G-112-04	Captures the variance between actual annual BCUC levies and the amount forecast in rates.	1 year
Non-controllable	Interest	G-7-03	Captures the impact on interest expense of interest rates variances and variances in the timing of long-term debt issues, as compared to what has been forecast in rates.	3 years
Non-controllable	Tax	G-141-09; G-44-12	Captures 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, Municipal or any other level of jurisdiction.	1 year
Non-controllable	Customer Service O&M	G-44-12	Captured the differences between the actual and forecasted expenditures for 2012 and 2013 ongoing operating costs of the in-sourced Customer Service activities, as well as the differences between actual and forecast spending in 2012 and 2013 for meter reading costs.	5 years proposed. See Section D3
Non-controllable	Pension and OPEB funding	G-135-99; G-141-09	Captures the difference between amounts funded by ratepayers for pension and OPEB and amounts actually paid out by the Company in a deferral account, on a net of tax basis.	n/a
Non-controllable	US GAAP Pension and OPEB Funded Status Account	G-44-12	Captures the accumulated other comprehensive income balance related to pensions and OPEBs; with an offsetting entry to the Pension and OPEB Funding deferral account. This deferral account will capture the changes in the accumulated other comprehensive income balance each year as determined by the external actuary. The Pension and OPEB funding account captures the funded status of pensions and OPEB.	n/a
Cost of Applications	NGV for Transportation	G-128-11	Captured the NGV Fuelling Service Application costs incurred in 2010 and 2011 and the Rate Schedule 16 Application costs. See Section D3 for further discussion.	3 years
Cost of Applications	Long term Resource Plan	G-44-12	Captures the costs to prepare the Long Term Resource Plan.	2 years
Cost of Applications	AES Inquiry Costs	G-44-12; G-201-12	Captures 75% of the costs related to the AES Inquiry.	5 years

FEI Existing Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Cost of Applications	Generic Cost of Capital (GCOC)		Captures the costs related to the GCOC Proceeding, less recoveries from other participants. See Section D3 for further discussion.	5 years proposed. See Section D3
Cost of Applications	Amalgamation and Rate Design		Captures FEI's share of the costs related to the Amalgamation and Rate Design proceeding, including any costs related to the subsequent reconsideration application that was filed on April 26, 2013. See Section D3 for further discussion.	3 years proposed. See Section D3
Other	2011 Customer Service O&M and Cost of Service	C-1-10; C-23-10; G-141-09	Captured the costs associated with the CCE project incurred prior to the project implementation and go live date of January 1, 2012 in addition to project costs incurred in the early months of 2012.	8 years
Other	Gas Asset Records Project	G-44-12	Captures the Gas Asset Records Project costs. See Section D3 for further discussion.	5 years
Other	BCOneCall Project	G-44-12	Captures the BCOneCall Project costs. See Section D3 for further discussion.	5 years
Other	Gains and Losses on Asset Disposition	G-141-09; G-44-12	Captures the amount of gains and losses on disposal of assets.	20 years
Other	Negative Salvage Provision	G-44-12	Captures the annual negative salvage provision calculated using the approved negative salvage rates, offset by the actual net removal costs incurred.	n/a

Appendix F5

NON RATE BASE DEFERRALS

1. OVERVIEW

FEI maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a return while, in contrast, non-rate base deferral accounts are outside of rate base and, subject to Commission approval, attract AFUDC.

The recommendation for one treatment over the other has primarily been one of timing, or as a means to stream cost recovery to a particular customer or group of customers separate from all other customers. In the case of a timing issue, if FEI is able to forecast balances for deferral accounts and include them in revenue requirements, then a rate base deferral account is the preferred treatment. In situations where the rates for a particular year have already been set and costs need to be recorded in a deferral account, that deferral account will be non-rate base. The non-rate base deferral account balance will attract an AFUDC rate until such time as rates are re-set under the next revenue requirement or during the annual review process of a PBR, and the account is transferred into rate base. Consistent with the Uniform System of Accounts, items that are recoverable from customers but not included in rate base (such as Work in Progress or non-rate base deferral accounts) are afforded AFUDC treatment so that the utility is allowed the opportunity to earn a fair return on costs prudently incurred to provide service to customers.

The following section discusses the existing non rate base deferral accounts for FEI.

2. FEI NON-RATE BASE DEFERRALS

2.1 *BIOMETHANE VARIANCE ACCOUNT (BVA)*

The BVA, approved pursuant to Commission Order G-194-10, captures the costs incurred to procure and process consumable biomethane gas, and the revenues collected through the biomethane energy recovery component of rates from customers electing to receive service under a biomethane service offering. The costs collected in the BVA comprise the biomethane commodity costs, the capital cost of service and O&M costs of FEI owned and operated upgrader facilities, as well as O&M costs attributable to the biomethane service offerings for customer enrolment, account finalization and billing adjustments.

Biomethane price-related variances collected in the BVA, determined after adjustment for unsold volumes of biomethane, are taken into account when determining future rates; deficits/surpluses are recovered from/refunded to customers through the Biomethane Energy Recovery Charge (BERC). The BVA balances and BERC are reviewed on a quarterly basis and, under normal circumstances, are adjusted on an annual basis with a January 1 effective date.

The following table summarises the information of the BVA account that was filed in the 2013 First Quarter Gas Cost Report on March 7, 2013. The 2012 actual and 2013 projected values are for the three supply projects that were accepted by the Commission at the time of the 2013

First Quarter Gas Cost Report, namely, Fraser Valley Biogas, Salmon Arm Landfill (approved in Order G-194-10) and the Kelowna Landfill (approved in Order E-19-12 on October 23, 2012). The Commission has since accepted the supply contracts for Seabreeze Farm, Earth Renu and Dicklands Farm, (approved in Order G-70-13 dated May 6, 2013); however, supply from these three projects is not expected until 2014.

Table F5-1: Biomethane Variance Account activity[1]

($000's)

Particulars	2012 Actual Gross	2012 Actual Tax Adjustment	2012 Actual Net of Tax	2013 Projected Gross	2013 Projected Tax Adjustment	2013 Projected Net of Tax
BVA Nominal Opening Balance (GJ)	42,331			79,569		
Purchases	60,717			92,317		
Sales	(23,479)			(75,789)		
BVA Nominal Closing Balance (GJ)	79,569			96,097		
BVA Deferral Account Opening Balance, Net of Tax			$ 340.3			$ 711.6
Biomethane Purchases	767.2	(191.8)	575.4	914.3	(228.6)	685.7
Biomethane Sales Recoveries	(272.7)	68.2	(204.5)	(886.4)	221.6	(664.8)
Operating & Maintenance Charges	0.5	(0.1)	0.4	246.0	(61.5)	184.5
Property Tax Charges	-	-	-	-	-	-
Upgrader Depreciation Provision	-		-	187.0		187.0
Income Tax Charge	-		-	(311.0)		(311.0)
Earned Return - Interest	-	-	-	109.0	(27.3)	81.8
Earned Return - Equity	-		-	104.0		104.0
Total Activity	495.0	(123.7)	371.2	362.9	(95.7)	267.1
Ending Balance, Net of Tax			$ 711.6			$ 978.7

Tax Rate for 2012 & 2013 25%

[1] The ending 2012 balance in this table reflects the actual recorded balance in the BVA as of December 31, 2012. The amount differs from the $13.6 thousand shown on Tab 3, Page 1 of the BVA Status Report filed April 30, 2013 as the Status Report includes the expected credit receivable from 79,569 GJ's of nominal biomethane inventory. The nominal inventory of 79,569 GJ's x the effective BERC rate of $11.696 x (1-25%) to account for the expected revenue on an after-tax basis equals $698 thousand; the difference between the two reported amounts.

As the costs and revenues in the BVA do not affect the cost of gas or margin in the RRA, and the BERC rate will continue to be reviewed and reset as part of the quarterly gas cost reporting process, no BVA imbalances have been forecast for 2014 through 2018.

2.2 THERMAL ENERGY SERVICES DEFERRAL ACCOUNT (TESDA)

The Thermal Energy Services Deferral account was approved by Commission Order G-141-09 to capture and record revenues and costs related to geo-exchange, solar-thermal and district energy systems. In the AES Inquiry Report, the Commission stated:

> *"The Panel concludes that the current TESDA, now maintained within FEI, should be reviewed and a methodology developed for its allocation and recovery. FEI is directed to file an application that sets out:*
>
> *(a) the circumstances where a deferral account would be established for a specific Thermal Energy Services project;*
>
> *(b) a methodology that defines costs that are allocated to the general TESDA and costs that may be allocated to a project-specific deferral account;*
>
> *(c) the types of costs that would be allocated to the TESDA or to a deferral account related to a specific Thermal Energy Services project;*
>
> *(d) a methodology for the recovery of the current TESDA, including setting out a timeline for the recovery of the current balance;*
>
> *(e) a methodology for the allocation and recovery of future additions to the TESDA including a timeline for the recovery of balances; and*
>
> *(f) a methodology that will allow any allocation of balances in the TESDA to be assigned to specific TES customers or to the utility shareholder in a manner that is fair and reasonable."*

As outlined in FEI's February 20, 2013 letter "FortisBC Energy Utilities Clarification Request Related to Upcoming Revenue Requirements":

> *"Subsequent to updating the COC/TPP, the FEU will file an application regarding allocation and recovery of TESDA. Without clarity on the COC/TPP and the resulting costs that will be allocated to the TESDA, an analysis of the forecasted recovery from the TESDA is not possible."*

As discussed in Section D4 as a result of these other ongoing processes, FEI has not addressed the allocation of corporate and shared services to the TESDA in this Application but has requested a deferral account to ensure that natural gas ratepayers are held whole.

2.3 EEC INCENTIVES FOR AES/TES

The EEC Incentives for AES/TES deferral account was approved in the 2012-2013 RRA Decision. In that decision, the Commission directed the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The Commission also directed that the recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application and noted that the next Panel would have the benefit of the AES Inquiry decision to help determine the appropriate treatment for these costs.

FEI will continue accumulating EEC incentive costs relating to AES/TES activities in this deferral account and will propose disposition of this account in its first Annual Review to be held in 2014. The reason for delaying the determination of disposition of this account is that FEI would first like to file the TESDA Report and the Transfer Pricing Policy/Code of Conduct review requested in the AES Inquiry Decision[2] to be undertaken with the Commission later in 2013. In those processes, FEI will address the issue of whether these costs are more appropriately captured in the TESDA and allocated to TES customers or whether they should remain in FEI and be recovered from natural gas customers.

2.4 KORP FEASIBILITY COSTS

The Commission approved the creation of the KORP Feasibility Costs deferral account through Commission Order G-101-12. In the Decision, the Commission directed FEI to establish a new non-rate base deferral account to record the Stage 2a feasibility expenses, to a maximum of $850 thousand, with treatment of interest rate and deferral period to be determined in the next Revenue Requirement.

In the most recent KORP status report filed with the Commission April 30th, 2013, FEI has amended the timeline for the completion of the KORP project until November 2018 and provided justification for this revised timeline. To date, approximately $325 thousand of the $850 thousand budget has been spent on feasibility costs. Due to this change in the timing of the completion of this project, FEI is proposing to delay the request for the disposition period until a future application.

2.5 EEC INCENTIVES

FEI will continue the use of the non-rate base EEC Incentive deferral account, attracting AFUDC, to capture the remaining portion of EEC costs above the $15.0 million approved

[2] Order G-201-12, Pages 89 and 90

amounts in rate base as incurred on an actual basis, to a maximum of $19.4 million in 2014 and up to the approved spending limits in 2015 through 2018 amongst the FEU. The non-rate base account reduces the risk of variability in EEC costs of customer participation in program costs that are embedded in delivery rates. That is, costs incurred over and above the forecast annual EEC rate base account additions of $15.0 million in 2014 through 2018, will be captured in the EEC Incentive non-rate base account. The additions to the non-rate base account will be tracked on a utility basis and allocated to the rate base Vancouver Island and Whistler EEC deferral when applicable.

Additionally, this account will continue to capture the interest rate buy-down amounts related to the On-Bill Financing program as approved through Commission Order G-163-12. That application requested approval to capture the difference between the Utility's Weighted Average Cost of Capital ("WACC") and the loan financing rate of 4.5 percent charged to customers, in the EEC Incentive Non-Rate Base deferral account. The account will continue to capture this difference for each customer loan until the loans are fully paid back by the customer.

As also discussed in Section D4, FEI is seeking approval in this Application to transfer any new amounts accumulated in this account, during the 2014 – 2018 revenue requirement period, to the existing rate base EEC deferral account in the following year, with amortization over 10 years commencing the year in which the balance is transferred.

2.6 *US GAAP UNCERTAIN TAX POSITIONS*

The Commission approved the creation of the US GAAP Uncertain Tax Positions deferral account through Commission Order G-44-12. This non-rate base deferral account, which does not earn AFUDC, is used to capture any differences on an ongoing basis that arise from the implementation of US GAAP Accounting Standards Board Interpretation No. 48. The balance at the end of 2012 was $1.1 million.

2.7 *MARK TO MARKET – HEDGING TRANSACTIONS*

This non-rate base deferral account, which does not earn AFUDC, was approved by Commission Order E-22-95 to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing. The balance at the end of 2012 was a $26.0 million credit.

2.8 *NON RATE BASE DEFERRALS ENTERING RATE BASE IN 2014 OR 2015*

The following is a list of all of the non rate base deferral accounts that will be entering rate base in 2014 or 2015. Discussion of each of these accounts is included in either the sections above, Appendix F4 or Section D4.

1. EEC Incentives (Annual ending balance transferred to rate base but account to remain non-rate base)

2. NGT Incentives
3. Fuelling Station Variance Account
4. Overhead and Marketing Recoveries from NGT Class of Service
5. Amalgamation and Rate Design Application Costs
6. Residual Deferral – Rider 8 Commodity Unbundling Volume Variance
7. Residual Deferral – Rider 4 2012 Delivery Refund Rider Volume Variance
8. On-Bill Financing Pilot Program
9. Tilbury Property Purchase (Subdividable Land)

Appendix F6

GAS 5 YEAR HISTORY OF O&M AND 5 YEAR FORECASTS

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
($000)

Line No.	Particulars	2008	2009	2010	2011	2012	Projection 2013	Approved 2013	Base 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	12)	(13)	(14)
1	M&E Costs	$ 38,394	$ 40,258	$ 43,405	$ 40,863	$ 50,708	$ 55,817	$ 59,097	$ 59,622	$ 61,209	$ 62,519	$ 64,159	$ 65,973	$ 68,428
2	COPE Costs	23,046	25,664	28,413	31,208	32,450	31,780	37,183	34,225	35,331	36,190	37,148	38,299	39,813
3	COPE Customer Services Costs	-	-	-	-	11,825	11,644	11,144	13,030	13,340	13,625	13,983	14,381	14,916
4	IBEW Costs	21,201	22,396	22,625	26,013	27,180	26,472	27,640	28,509	29,724	30,578	31,380	32,274	33,475
5														
6	**Labour Costs**	**82,641**	**88,318**	**94,443**	**98,084**	**122,164**	**125,713**	**135,064**	**135,387**	**139,604**	**142,913**	**146,670**	**150,926**	**156,633**
7														
8	Vehicle Costs	5,001	4,926	3,625	4,001	3,807	3,855	3,685	4,018	4,149	4,236	4,325	4,416	4,509
9	Employee Expenses	4,422	4,254	5,805	5,859	5,898	5,671	5,716	5,719	5,828	5,955	6,080	6,208	6,339
10	Materials and Supplies	5,671	5,545	6,738	7,500	7,903	6,841	7,019	6,929	7,125	7,340	7,495	7,652	7,813
11	Computer Costs	7,611	8,210	10,214	10,867	14,570	15,274	14,769	15,603	16,028	16,365	16,708	17,059	17,417
12	Fees and Administration Costs	28,163	25,498	29,199	30,449	38,611	38,449	37,905	38,110	41,214	42,380	43,590	44,840	46,137
13	Contractor Costs	55,593	58,092	62,151	62,211	31,955	40,896	38,335	30,240	31,081	31,658	32,941	33,946	35,139
14	Facilities	10,792	11,974	13,023	12,805	15,486	13,976	14,284	14,035	14,545	15,206	15,625	15,978	16,439
15	Recoveries & Revenue	(14,155)	(14,870)	(18,680)	(18,169)	(20,689)	(19,055)	(20,774)	(19,055)	(19,642)	(20,292)	(20,991)	(21,712)	(22,518)
16														
17	**Non-Labour Costs**	**103,098**	**103,628**	**112,075**	**115,522**	**97,540**	**105,906**	**100,939**	**95,598**	**100,329**	**102,847**	**105,773**	**108,388**	**111,274**
18														
19	**Total Gross O&M Expenses**	**185,739**	**191,946**	**206,518**	**213,606**	**219,704**	**231,618**	**236,003**	**230,985**	**239,933**	**245,760**	**252,443**	**259,314**	**267,907**
20														
21	Less: Vehicle Lease Reclass	(1,988)	(1,804)	-	-	-	-	-	-	-	-	-	-	-
22	Less: Capitalized Overhead	(27,543)	(28,115)	(28,905)	(30,055)	(31,779)	(33,040)	(33,040)	(32,338)	(33,591)	(34,406)	(35,342)	(36,304)	(37,507)
23														
24	**Total O&M Expenses**	**$ 156,208**	**$ 162,027**	**$ 177,613**	**$ 183,551**	**$ 187,925**	**$ 198,578**	**$ 202,963**	**$ 198,647**	**$ 206,343**	**$ 211,354**	**$ 217,101**	**$ 223,010**	**$ 230,400**

Appendix F6

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Page 1)
($000)

Line No.	Particulars	Reference	2008	2009	2010	2011	2012	Projection 2013	Approved 2013	Base 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Distribution - Supervision	110-11	$ 8,636	$ 8,527	$ 10,229	$ 10,456	$ 10,578	$ 11,194	$ 11,026	$ 12,180	$ 12,440	$ 12,692	$ 12,993	$ 13,322	$ 13,741
2	Distribution - Supervision Total	110-10	8,636	8,527	10,229	10,456	10,578	11,194	11,026	12,180	12,440	12,692	12,993	13,322	13,741
3															
4	Operation Centre - Distribution	110-21	$ 7,247	$ 7,532	$ 8,491	$ 8,615	$ 10,112	$ 9,901	$ 11,074	$ 10,950	$ 11,204	$ 11,476	$ 11,780	$ 12,197	$ 12,707
5	Preventative Maintenance - Distribution	110-22	$ 2,222	$ 2,179	$ 2,085	$ 2,314	$ 2,644	$ 2,844	$ 2,990	$ 3,118	$ 3,323	$ 3,394	$ 3,478	$ 3,571	$ 3,689
6	Operations - Distribution	110-23	$ 4,865	$ 5,232	$ 5,575	$ 5,685	$ 5,538	$ 6,409	$ 5,904	$ 6,801	$ 6,331	$ 6,474	$ 6,636	$ 6,810	$ 7,020
7	Emergency Management - Distribution	110-24	$ 6,415	$ 6,082	$ 4,509	$ 4,664	$ 5,405	$ 5,337	$ 5,077	$ 6,084	$ 6,480	$ 6,618	$ 6,792	$ 6,987	$ 7,252
8	Field Training - Distribution	110-25	$ -	$ -	$ 2,816	$ 2,495	$ 1,746	$ 3,153	$ 4,088	$ 3,468	$ 3,547	$ 3,623	$ 3,716	$ 3,817	$ 3,947
9	Meter Exchange - Distribution	110-26	$ 1,919	$ 2,025	$ 1,954	$ 2,171	$ 2,397	$ 2,373	$ 2,231	$ 2,601	$ 3,161	$ 3,221	$ 3,293	$ 3,370	$ 3,469
10	Distribution Operations Total	110-20	22,667	23,050	25,430	25,944	27,842	30,018	31,363	33,022	34,046	34,805	35,694	36,752	38,082
11															
12	Corrective - Distribution	110-31	$ 3,354	$ 3,360	$ 4,075	$ 3,927	$ 5,564	$ 5,559	$ 4,643	$ 5,944	$ 5,979	$ 6,094	$ 6,229	$ 6,375	$ 6,557
13	Distribution Maintenance Total	110-30	3,354	3,360	4,075	3,927	5,564	5,559	4,643	5,944	5,979	6,094	6,229	6,375	6,557
14															
15	Account Services - Distribution	110-41	$ 692	$ 926	$ 893	$ 962	$ 1,111	$ 1,081	$ 1,004	$ 1,197	$ 1,249	$ 1,276	$ 1,308	$ 1,343	$ 1,390
16	Bad Debt Management - Distribution	110-42	$ 589	$ 691	$ 363	$ 576	$ 585	$ 443	$ 599	$ 606	$ 569	$ 583	$ 605	$ 631	$ 673
17	Distribution Meter to Cash Total	110-40	1,281	1,617	1,255	1,538	1,697	1,524	1,603	1,803	1,818	1,859	1,913	1,975	2,062
18															
19	**Distribution Total**	**110**	**35,938**	**36,554**	**40,989**	**41,864**	**45,680**	**48,295**	**48,635**	**52,949**	**54,282**	**55,450**	**56,829**	**58,423**	**60,443**
20															
21	Transmission - Supervision	120-11	$ 1,238	$ 1,684	$ 999	$ 963	$ 535	$ 606	$ 482	$ 678	$ 694	$ 709	$ 727	$ 748	$ 775
22	Transmission - Supervision Total	120-10	1,238	1,684	999	963	535	606	482	678	694	709	727	748	775
23															
24	Pipeline / Right of Way Operations	120-21	$ 7,573	$ 7,724	$ 6,146	$ 6,977	$ 7,287	$ 6,163	$ 6,096	$ 6,593	$ 6,755	$ 6,920	$ 7,107	$ 7,307	$ 7,547
25	Compression Operations	120-22	$ 2,135	$ 2,925	$ 3,360	$ 2,369	$ 1,827	$ 1,813	$ 2,112	$ 1,967	$ 2,023	$ 2,080	$ 2,145	$ 2,215	$ 2,298
26	Measurement Control Operations	120-23	$ -	$ -	$ -	$ 72	$ 103	$ -	$ -	$ 14	$ 17	$ 20	$ 24	$ 27	$ 33
27	Transmission Operations Total	120-20	9,708	10,649	9,506	9,417	9,217	7,976	8,208	8,575	8,795	9,021	9,276	9,549	9,878
28															
29	Pipeline / Right of Way - Maintenance	120-31	$ 338	$ 899	$ 864	$ 1,232	$ 1,830	$ 3,206	$ 2,707	$ 3,220	$ 3,263	$ 3,310	$ 3,359	$ 3,409	$ 3,460
30	Compression - Maintenance	120-32	$ 534	$ 775	$ 722	$ 565	$ 554	$ 1,216	$ 1,147	$ 1,220	$ 1,230	$ 1,243	$ 1,255	$ 1,268	$ 1,281
31	Measurement Control Maintenance	120-33	$ -	$ -	$ -	$ 84	$ 117	$ 201	$ 119	$ 202	$ 204	$ 206	$ 208	$ 210	$ 212
32	Transmission Maintenance Total	120-30	872	1,674	1,587	1,881	2,501	4,623	3,973	4,642	4,697	4,759	4,822	4,887	4,953
33															
34	**Transmission Total**	**120**	**11,818**	**14,007**	**12,091**	**12,261**	**12,253**	**13,205**	**12,663**	**13,894**	**14,186**	**14,488**	**14,825**	**15,184**	**15,605**
35															
36	LNG Plant Operations	130-11	$ 721	$ 854	$ 942	$ 1,420	$ 1,601	$ 1,717	$ 1,617	$ 1,857	$ 2,218	$ 2,872	$ 2,932	$ 3,117	$ 3,078
37	LNG Plant Operations Total	130-10	721	854	942	1,420	1,601	1,717	1,617	1,857	2,218	2,872	2,932	3,117	3,078
38															
39	LNG Plant Maintenance	130-21	$ 253	$ 246	$ 421	$ 211	$ 272	$ 292	$ 274	$ 315	$ 377	$ 488	$ 498	$ 529	$ 523
40	LNG Plant Maintenance Total	130-20	253	246	421	211	272	292	274	315	377	488	498	529	523
41			-	-	-	-	-	-	-	-	-	-	-	-	-
42	**LNG Plant Total**	**130**	**974**	**1,099**	**1,363**	**1,631**	**1,873**	**2,009**	**1,891**	**2,172**	**2,595**	**3,360**	**3,430**	**3,646**	**3,600**
43															
44	**Operations Total**	**100**	**48,730**	**51,661**	**54,444**	**55,756**	**59,806**	**63,509**	**63,189**	**69,016**	**71,062**	**73,298**	**75,084**	**77,253**	**79,648**
45															
46	Customer Service - Supervision	210-11	$ -	$ -	$ (14)	$ 739	$ 482	$ 566	$ 566	$ 622	$ 636	$ 649	$ 666	$ 684	$ 707
47	Customer Assistance	210-12	$ 46,835	$ 47,325	$ 48,690	$ 50,039	$ 11,513	$ 11,480	$ 11,493	$ 13,954	$ 14,290	$ 14,601	$ 14,992	$ 15,429	$ 16,019
48	Customer Billing	210-13	$ 601	$ 816	$ 986	$ 718	$ 18,586	$ 14,494	$ 14,494	$ 12,696	$ 12,988	$ 13,288	$ 13,625	$ 13,984	$ 14,410
49	Meter Reading	210-14	$ -	$ -	$ -	$ -	$ 12,178	$ 19,696	$ 19,696	$ 11,079	$ 11,270	$ 11,484	$ 12,148	$ 12,381	$ 13,064
50	Credit & Collections	210-15	$ 3,582	$ 4,022	$ 1,957	$ 3,727	$ 3,028	$ 3,787	$ 3,851	$ 3,789	$ 3,861	$ 3,942	$ 4,025	$ 4,110	$ 4,196
51	Customer Operations	210-16	$ 1,078	$ 1,004	$ 1,659	$ 1,352	$ 2,385	$ 2,088	$ 2,353	$ 2,258	$ 2,309	$ 2,358	$ 2,417	$ 2,480	$ 2,559
52	Customer Service Total	210-10	52,095	53,167	53,278	56,575	48,172	52,110	52,452	44,398	45,352	46,323	47,873	49,068	50,956
53															
54	**Customer Service Total**	**210**	**52,095**	**53,167**	**53,278**	**56,575**	**48,172**	**52,110**	**52,452**	**44,398**	**45,352**	**46,323**	**47,873**	**49,068**	**50,956**
55															
56	**Customer Service Total**	**200**	**52,095**	**53,167**	**53,278**	**56,575**	**48,172**	**52,110**	**52,452**	**44,398**	**45,352**	**46,323**	**47,873**	**49,068**	**50,956**

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Page 2)
($000)

Line No.	Particulars	Reference	2008	2009	2010	2011	2012	Projection 2013	Approved 2013	Base 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
1	Energy Solutions & External Relations - Supervision	310-11	$ 651	$ 906	$ 804	$ 752	$ 614	$ 671	$ 796	$ 687	$ 700	$ 715	$ 731	$ 747	$ 765
2	Energy Solutions	310-12	$ 2,845	$ 3,043	$ 4,734	$ 4,559	$ 5,134	$ 5,117	$ 4,991	$ 5,677	$ 6,009	$ 6,139	$ 6,297	$ 6,471	$ 6,696
3	Energy Efficiency	310-13	$ 1,740	$ 1,624	$ (7)	$ (1)	$ 117	$ 301	$ 120	$ 302	$ 308	$ 314	$ 321	$ 327	$ 334
4	Corporate Communications and External Relations	310-14	$ 3,943	$ 4,317	$ 5,434	$ 5,292	$ 7,212	$ 6,988	$ 6,155	$ 7,354	$ 8,609	$ 8,792	$ 8,995	$ 9,210	$ 9,461
5	Forecasting, Market & Business Development	310-15	$ 2,193	$ 2,581	$ 3,671	$ 4,854	$ 4,998	$ 6,138	$ 6,119	$ 6,701	$ 7,649	$ 7,810	$ 8,000	$ 8,206	$ 8,464
6	Energy Solutions & External Relations Total	310-10	11,372	12,472	14,636	15,456	18,075	19,215	18,181	20,721	23,275	23,771	24,343	24,961	25,721
7															
8	**Energy Solutions & External Relations Total**	**310**	**11,372**	**12,472**	**14,636**	**15,456**	**18,075**	**19,215**	**18,181**	**20,721**	**23,275**	**23,771**	**24,343**	**24,961**	**25,721**
9															
10	**Energy Solutions & External Relations Total**	**300**	**11,372**	**12,472**	**14,636**	**15,456**	**18,075**	**19,215**	**18,181**	**20,721**	**23,275**	**23,771**	**24,343**	**24,961**	**25,721**
11															
12	Energy Supply & Resource Development	410-11	$ 674	$ 964	$ 803	$ 1,869	$ 1,937	$ 2,550	$ 2,136	$ 2,821	$ 2,938	$ 3,002	$ 3,080	$ 3,166	$ 3,276
13	Gas Control	410-12	$ 1,225	$ 1,175	$ 1,272	$ 1,541	$ 1,551	$ 1,451	$ 1,602	$ 1,619	$ 1,800	$ 1,916	$ 1,960	$ 2,009	$ 2,074
14	Energy Supply & Resource Development Total	410-10	1,899	2,139	2,075	3,409	3,488	4,000	3,738	4,440	4,738	4,918	5,040	5,175	5,350
15															
16	**Energy Supply & Resource Development Total**	**410**	**1,899**	**2,139**	**2,075**	**3,409**	**3,488**	**4,000**	**3,738**	**4,440**	**4,738**	**4,918**	**5,040**	**5,175**	**5,350**
17															
18	Information Technology - Supervision	420-11	$ 1,868	$ 2,442	$ 3,058	$ 3,697	$ 4,172	$ 4,001	$ 4,577	$ 4,188	$ 4,276	$ 4,367	$ 4,468	$ 4,576	$ 4,702
19	Application Management	420-12	$ 7,130	$ 7,930	$ 8,344	$ 8,691	$ 11,251	$ 11,980	$ 12,083	$ 10,737	$ 11,101	$ 11,340	$ 11,616	$ 11,915	$ 12,283
20	Infrastructure Management	420-13	$ 5,340	$ 5,601	$ 5,918	$ 6,266	$ 8,018	$ 8,236	$ 8,719	$ 8,843	$ 9,015	$ 9,204	$ 9,402	$ 9,607	$ 9,823
21	Information Technology Total	420-10	14,338	15,972	17,320	18,654	23,442	24,217	25,379	23,768	24,392	24,911	25,487	26,097	26,809
22															
23	**Information Technology Total**	**420**	**14,338**	**15,972**	**17,320**	**18,654**	**23,442**	**24,217**	**25,379**	**23,768**	**24,392**	**24,911**	**25,487**	**26,097**	**26,809**
24															
25	System Planning	430-11	$ 3,610	$ 3,973	$ 5,693	$ 6,187	$ 5,672	$ 7,675	$ 8,394	$ 8,405	$ 8,859	$ 8,698	$ 8,915	$ 9,153	$ 9,456
26	Engineering	430-12	$ 5,070	$ 5,620	$ 7,350	$ 6,725	$ 6,803	$ 6,760	$ 7,027	$ 7,484	$ 7,657	$ 7,823	$ 8,024	$ 8,244	$ 8,531
27	Project Management	430-13	$ 279	$ 237	$ 522	$ 1,417	$ 1,125	$ 1,021	$ 1,535	$ 1,128	$ 1,220	$ 1,245	$ 1,275	$ 1,295	$ 1,338
28	Engineering Services & Project Management Total	430-10	8,959	9,830	13,566	14,329	13,599	15,456	16,956	17,018	17,736	17,766	18,214	18,692	19,325
29															
30	**Engineering Services & Project Management Total**	**430**	**8,959**	**9,830**	**13,566**	**14,329**	**13,599**	**15,456**	**16,956**	**17,018**	**17,736**	**17,766**	**18,214**	**18,692**	**19,325**
31															
32	Supply Chain	440-11	$ 3,374	$ 3,733	$ 4,372	$ 4,296	$ 4,420	$ 4,450	$ 4,884	$ 4,896	$ 5,234	$ 5,350	$ 5,486	$ 5,635	$ 5,823
33	Measurement	440-12	$ 4,120	$ 4,350	$ 5,340	$ 5,008	$ 5,548	$ 6,124	$ 6,688	$ 6,768	$ 6,983	$ 7,150	$ 7,347	$ 7,563	$ 7,836
34	Property Services	440-13	$ 1,011	$ 991	$ 1,204	$ 1,276	$ 1,070	$ 1,293	$ 1,418	$ 1,447	$ 1,481	$ 1,513	$ 1,553	$ 1,596	$ 1,654
35	Operations Support Total	440-10	8,505	9,074	10,916	10,580	11,038	11,867	12,990	13,111	13,698	14,013	14,386	14,794	15,313
36															
37	**Operations Support Total**	**440**	**8,505**	**9,074**	**10,916**	**10,580**	**11,038**	**11,867**	**12,990**	**13,111**	**13,698**	**14,013**	**14,386**	**14,794**	**15,313**
38															
39	Facilities Management	450-11	$ 5,890	$ 6,524	$ 7,329	$ 6,835	$ 9,563	$ 9,249	$ 9,259	$ 9,504	$ 9,959	$ 10,170	$ 10,469	$ 10,705	$ 11,065
40	Facilities Total	450-10	5,890	6,524	7,329	6,835	9,563	9,249	9,259	9,504	9,959	10,170	10,469	10,705	11,065
41															
42	**Facilities Total**	**450**	**5,890**	**6,524**	**7,329**	**6,835**	**9,563**	**9,249**	**9,259**	**9,504**	**9,959**	**10,170**	**10,469**	**10,705**	**11,065**
43															
44	Environment Health & Safety	460-11	$ 1,191	$ 1,457	$ 2,427	$ 2,445	$ 2,481	$ 2,681	$ 2,999	$ 2,872	$ 2,934	$ 2,997	$ 3,069	$ 3,147	$ 3,242
45	Environment Health & Safety Total	460-10	1,191	1,457	2,427	2,445	2,481	2,681	2,999	2,872	2,934	2,997	3,069	3,147	3,242
46															
47	**Environment Health & Safety Total**	**460**	**1,191**	**1,457**	**2,427**	**2,445**	**2,481**	**2,681**	**2,999**	**2,872**	**2,934**	**2,997**	**3,069**	**3,147**	**3,242**
48															
49															
50	**Business Services Total**	**400**	**40,783**	**44,996**	**53,632**	**56,252**	**63,611**	**67,470**	**71,321**	**70,712**	**73,457**	**74,775**	**76,666**	**78,610**	**81,103**

Appendix F6

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Page 3)
($000)

Line No.	Particulars	BCUC Reference	ACTUAL 2008	ACTUAL 2009	ACTUAL 2010	ACTUAL 2011	ACTUAL 2012	Projection 2013	Approved 2013	Base 2013	FCST-Yr1 2014	FCST-Yr2 2015	FCST-Yr3 2016	FCST-Yr4 2017	FCST-Yr5 2018
	(1)	(2)	(3)			(4)	(5)	(4)			(5)	(6)	(7)	(8)	(9)
1	Financial & Regulatory Services	510-11	$ 11,009	$ 11,623	$ 12,177	$ 12,064	$ 12,149	$ 13,279	$ 14,184	$ 15,079	$ 15,401	$ 15,728	$ 16,101	$ 16,502	$ 16,987
2	Financial & Regulatory Services Total	510-10	11,009	11,623	12,177	12,064	12,149	13,279	14,184	15,079	15,401	15,728	16,101	16,502	16,987
3															
4	**Financial & Regulatory Services Total**	**510**	**11,009**	**11,623**	**12,177**	**12,064**	**12,149**	**13,279**	**14,184**	**15,079**	**15,401**	**15,728**	**16,101**	**16,502**	**16,987**
5															
6	Human Resources	520-11	$ 6,278	$ 6,875	$ 8,823	$ 8,170	$ 8,610	$ 8,458	$ 8,511	$ 9,192	$ 9,399	$ 9,601	$ 9,841	$ 10,102	$ 10,431
7	Human Resources Total	520-10	6,278	6,875	8,823	8,170	8,610	8,458	8,511	9,192	9,399	9,601	9,841	10,102	10,431
8															
9	**Human Resources Total**	**520**	**6,278**	**6,875**	**8,823**	**8,170**	**8,610**	**8,458**	**8,511**	**9,192**	**9,399**	**9,601**	**9,841**	**10,102**	**10,431**
10															
11	Legal	530-11	$ 1,158	$ 1,888	$ 2,039	$ 2,280	$ 1,917	$ 2,282	$ 2,282	$ 2,282	$ 2,325	$ 2,374	$ 2,424	$ 2,475	$ 2,527
12	Internal Audit	530-12	$ 526	$ 526	$ 586	$ 653	$ 695	$ 755	$ 755	$ 755	$ 769	$ 785	$ 802	$ 819	$ 836
13	Risk Management/Insurance	530-13	$ 4,932	$ 4,995	$ 4,744	$ 4,963	$ 4,754	$ 4,898	$ 4,898	$ 4,991	$ 5,277	$ 5,583	$ 5,909	$ 6,250	$ 6,612
14	Governance	530-10	6,615	7,409	7,368	7,895	7,366	7,935	7,935	8,028	8,371	8,742	9,135	9,544	9,974
15															
16	**Governance Total**	**530**	**6,615**	**7,409**	**7,368**	**7,895**	**7,366**	**7,935**	**7,935**	**8,028**	**8,371**	**8,742**	**9,135**	**9,544**	**9,974**
17															
18	Administration & General	540-11	$ 2,302	$ 26	$ 3,885	$ 2,414	$ 226	$ 269	$ (46)	$ 562	$ 575	$ 588	$ 602	$ 616	$ 633
19	Shared Services Agreement	540-12	$ (1,778)	$ (2,615)	$ (5,116)	$ (5,086)	$ (5,984)	$ (6,483)	$ (5,581)	$ (6,723)	$ (6,960)	$ (7,065)	$ (7,201)	$ (7,341)	$ (7,547)
20	Retiree Benefits	540-16	$ 8,332	$ 6,332	$ 3,389	$ 4,111	$ 7,673	$ 5,857	$ 5,857	$ -	$ -	$ -	$ -	$ -	$ -
21	Corporate Total	540-10	8,857	3,743	2,158	1,439	1,915	(357)	230	(6,161)	(6,385)	(6,478)	(6,600)	(6,725)	(6,914)
22															
23	**Corporate Total**	**540**	**8,857**	**3,743**	**2,158**	**1,439**	**1,915**	**(357)**	**230**	**(6,161)**	**(6,385)**	**(6,478)**	**(6,600)**	**(6,725)**	**(6,914)**
24															
25	**Corporate Services Total**	**500**	**32,759**	**29,650**	**30,527**	**29,568**	**30,041**	**29,314**	**30,860**	**26,139**	**26,786**	**27,594**	**28,477**	**29,422**	**30,479**
26															
27	**Total Gross O&M Expenses**		**185,739**	**191,946**	**206,518**	**213,606**	**219,704**	**231,618**	**236,003**	**230,985**	**239,934**	**245,760**	**252,443**	**259,314**	**267,907**
28															
29	Less: Vehicle Reclass		$ (1,988)	$ (1,804)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Less: Capitalized Overhead		$ (27,543)	$ (28,115)	$ (28,905)	$ (30,055)	$ (31,779)	$ (33,040)	$ (33,040)	$ (32,338)	$ (33,591)	$ (34,406)	$ (35,342)	$ (36,304)	$ (37,507)
31															
32	**Total O&M Expenses**		**$ 156,208**	**$ 162,027**	**$ 177,613**	**$ 183,551**	**$ 187,925**	**$ 198,578**	**$ 202,963**	**$ 198,647**	**$ 206,343**	**$ 211,354**	**$ 217,101**	**$ 223,010**	**$ 230,400**

Appendix F7

2010-2011 REVENUE REQUIREMENTS – IMPACTS FROM HARMONIZED SALES TAX

1 GENERAL

This appendix includes the calculation of the 2013 revenue requirement impact from the conversion to PST from HST and the historic 2010 and 2011 application for the conversion from PST to HST approved through Commission Order L-96-10. The explanation of the methodology of calculating the impacts for 2013 is included in the 2010-2011 filing.

2 ATTACHMENTS

The following attachments are included with this appendix:

1. FEI Summary of PST Expenditures for 2013 Revenue Requirements
2. Harmonized Sales Tax Impacts on the 2010-2011 Revenue Requirements

FEI Summary of PST Expenditures for 2013 Revenue Requirements

Line No.	Particulars	2006	2007	2008	2009	4 Yr Average	PST Estimated Expenditures * 2013	Method to Determine 2013 Estimates of PST Expenditures
		Amounts in $ thousands — Actual PST Paid by Year						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	O&M	647	643	713	779	695	552	O&M PST % applied to 2013 O&M forecast by cost element
2	Meters	727	711	714	790	736	552	Four year average
3	Capital	1,116	1,236	1,609	1,972	1,483	1,112	Four year average
4	Total PST per SAP report	**2,490**	**2,590**	**3,036**	**3,541**	**2,914**	**2,215**	
5	PST on vehicle lease payments	194	186	171	181	183	82	Approx 40% subject to restricted input tax credit (vehicles under 3000 kg)
6	PST on vehicle operating costs	60	88	101	100	88	87	Vehicle Opex PST% applied to 2013 Vehicle Opex forecast
7	PST on company use	15	14	17	10	14	-	N/A - subject to restricted input tax credit
8	PST on station heaters	88	76	89	49	75	-	N/A - subject to restricted input tax credit
9	Motor fuel tax	105	170	190	180	161	-	N/A - unaffected by HST/PST implementation
10	ICE levy	-	2	5	5	3	2	Four year average
11	Less: HST applicable to meals & entertainment						(70)	Calculated as 7% of 2013 meals & entertainment forecast
12	**Total SST remitted (2007/2008 per BCUC IR 1.143.1)**	**2,951**	**3,126**	**3,610**	**4,066**	**3,438**	**2,317**	
13								
14	* 2013 for nine months (April 1st to December 31st)							
15								
16	Revenue Requirement Impact ($000s)							
17	O&M (Rows 1, 5, 6, 10, 11)						653	
18	Depreciation Expense (related to Rows 2 and 3)						39	
19	Earned Return (related to Rows 2 and 3)						49	
20	Income Tax Expense (related to Rows 2 and 3)						1	
21	**Revenue Requirement Impact ($000s)**						743	

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September 27, 2010

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: Harmonized Sales Tax Impacts on the

2010-2011 Revenue Requirements of the Terasen Utilities (or the "Companies") comprised of Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW")

On November 26, 2009, the British Columbia Utilities Commission (the "Commission") issued Orders No. G-141-09 and No. G-140-09 accepting the 2010-2011 Negotiated Settlement Agreements for TGI and TGVI respectively on their 2010-2011 Revenue Requirements Applications. On September 1, 2010, the Commission issued Order No. G-138-10 regarding TGW's 2010-2011 Revenue Requirements and Rates Application ("RRA").

During the regulatory review process for each of the Terasen Utilities' 2010-2011 RRAs, the Companies committed to performing analysis and validation to determine the impact of the Harmonized Sales Tax ("HST") on each company and, in their 2010-2011 RRAs, the Companies sought approval to capture the impact of the transition to HST in their respective tax deferral accounts to be returned to customers after 2011. Further, in Order No. G-138-10, the Commission ordered that "TGW shall establish separate sub-accounts to specifically track Harmonized Sales Tax adjustments related to Operations and Maintenance and capital items".

References to HST discussion in the proceeding record of each of the Terasen Utilities is as follows:

- TGI Exhibit B-4, Response to BCUC IR 1.145.1;
- TGVI Exhibit B-7, Response to BCUC IR 2.36 series; and
- TGW Exhibit B-5, Response to BCUC IR 1.10 series.

The Terasen Utilities have now performed the necessary analysis, with the goal of determining the amounts as correctly as possible, using various methods to validate the final results.

In the attached detailed report, the Terasen Utilities discuss the analysis performed, steps undertaken and the resulting revenue requirements impact by company for each of 2010 and 2011. The Terasen Utilities propose to record the revenue requirements impact by year in the HST deferral accounts of each of the Companies. The amounts recorded in the HST deferral accounts would be returned to customers, net of HST implementation costs, as part of the Terasen Utilities' 2012 revenue requirements applications.

The Terasen Utilities respectfully request the Commission's acceptance of the methodology used, and that the resulting amounts will be returned to customers through the existing Tax Variance deferral accounts. The Terasen Utilities also request the Commission's acceptance that the final amounts to be returned to customers, net of the costs of implementation, be addressed as part of their 2012 revenue requirements applications.

If you require further information or have any questions regarding this submission, please contact the undersigned or Diane Roy at (604) 576-7349.

Yours very truly,

on behalf of the TERASEN UTILITIES

Original signed by: Diane Roy

For: Tom A. Loski

Attachments

cc (email only): Parties to the Terasen Utilities' 2010-2011 RRAs

Background:

In July of 2009, the Governments of Canada and British Columbia announced that the Harmonized Sales Tax ("HST") would be implemented in British Columbia effective July 1, 2010.

On December 15, 2009, Federal Bill C-62 received Royal Assent. Bill C-62 includes draft legislation to amend the *Excise Tax Act* to implement the new fully harmonized value-added framework in British Columbia and Ontario.

On April 29, 2010, Provincial Bill 9 received Royal Assent. Bill 9 repeals the *Social Service Tax Act* and implements certain HST Point-of-Sale rebates and the Residential Energy Credit.

On February 19, 2010, the Provincial Ministry of Finance issued HST Notice #4. This Notice provides that certain Input Tax Credits ("ITCs") are recaptured for large businesses. The associated regulations were published in the Canada Gazette on June 30, 2010.

Under the legislation, certain goods and services which were subject to Social Service Tax ("SST") of 7% prior to July 2010, will be subject to HST instead, and the company will be able to claim a full ITC for the amount of the HST on these costs. This will result in a 7% lower cost for items in this category, which include:

- materials and freight on materials, including pipe;
- legal fees incurred in BC;
- office supplies;
- furniture and equipment;
- software licenses and computer hardware;
- vehicles over 3000 kg; and
- maintenance contracts for office and computer equipment and software.

Meals and entertainment costs were not subject to SST, but are subject to HST. The legislation calls for a recapture of ITCs on the provincial portion of HST on these costs, resulting in increased costs for meals and entertainment expenditures.

Other costs, including most telecommunications, passenger vehicle lease costs, passenger vehicle purchases, passenger vehicle rentals and heat and electricity were subject to SST. The HST restricts or recaptures ITCs for the provincial portion of HST on these costs; therefore, these types of costs will remain unchanged under an HST regime.

On September 13th, 2010 it was announced that a referendum on the continuation of the HST will be held in British Columbia on September 24, 2011. 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. Should the HST be repealed, the impact, including the implementation costs, will be assessed and reflected in a subsequent application.

HST Revenue Requirement Impact Analysis:

The Terasen Utilities, comprised of Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW"), have completed their analysis of the impact of the implementation of the HST on the 2010 and 2011 Revenue Requirements. The following process was followed in determining the estimates for the Revenue Requirement impacts for those two years for each entity (TGI, TGVI and TGW):

Step 1: ***SAP[1] Historical Information***

1. An SAP report was developed, detailing:
   a. the amount of SST paid by cost element (account); and
   b. the split of that SST between amounts relating to O&M, meter purchases, and capital.
2. The SAP report was run for each of 2006, 2007, 2008 and 2009 for each of TGI, TGVI and TGW.
3. The SAP report for each year was reconciled to the total SST remittance for each of those years. There were a few reconciling items between the SAP reports run and the total SST remitted for each year. These consisted of SST on vehicle lease and operating costs, gas used in station heaters and for company use, as well as motor fuel tax and the ICE levy. Since HST on vehicle lease payments for vehicles under 3,000 kg (approximately 40% of the total) and HST on gas used in station heaters and company use will be subject to restricted ITCs, the SST relating to these items was removed from the calculation of HST savings. The motor fuel tax is also unaffected by the HST implementation and is therefore expected to continue unchanged.
4. The remaining items where a SST savings will be relevant are O&M, meters, capital, vehicle expenses, vehicle lease payments for vehicles over 3,000 kg, and the ICE Levy. In addition, there will be incremental HST paid on meals and entertainment.

Step 2: ***Determination of SST in O&M and Vehicle Operating Costs (TGI and TGVI)***

1. For each cost element (account), the four-year average O&M and the four-year average of O&M that is subject to SST were calculated, to derive an average percentage of O&M that is subject to SST by cost element.
2. The average percentage of O&M subject to SST by cost element was then applied to the forecast O&M by cost element that was included in the determination of rates for 2010 and 2011 (July to December of 2010 and full year 2011).
3. The resulting amounts were multiplied by 7% to determine the SST amounts by cost element embedded in the O&M.
4. Any SST that will be subject to restricted tax credits was removed.

[1] SAP is the core business application that supports the Company's financial, supply chain, Human Resources, Pay/time, Work Management, Preventive Maintenance and Meter Management business Processes.

Step 3: ***Determination of SST in Meters, Capital, Vehicle Lease Payments, and ICE Levy, and O&M for TGW***

1. The average SST applicable to each of these items was determined as a simple average for the four years, with 2010 calculated at ½ of the annual amount to represent the July to December spending. For vehicle lease payments, this amount was then reduced by 40% to account for those vehicles under 3,000 kilograms that would be subject to the restricted input tax credit.

Step 4: ***Determination of Impact on Revenue Requirements***

1. For O&M (excluding the meals & entertainment restricted input tax credit), Vehicle Operating Costs, and ICE levy, the SST savings revenue requirement impact is equal to the projected SST savings.
2. For Capital, the revenue requirement impact was determined for 2010 and 2011 by calculating the earned return, depreciation using the average depreciation rate (2.77% for TGI, 2.52% for TGVI and 2.69% for TGW), and income tax using the applicable Capital Cost Allowance ("CCA") and income tax rates.
3. For Meters, the revenue requirement impact was determined for 2010 and 2011 by calculating the earned return, depreciation using the meter asset class depreciation rate (5.31% for TGI and 4.37% for TGVI), and income tax using the applicable CCA and income tax rates.

Summary

For TGI, a high level analysis was performed of the reasonableness of the results. Given the increase in O&M for TGI in 2010 as compared to 2011, a higher growth in SST savings was originally expected, but it was determined that since 85% of the increase in O&M is in the labour category, which does not have any SST associated with it, the estimated amount of SST savings is reasonable. For capital, we considered inflating the four year average for growth in capital spending in 2010 and 2011, but due to the disconnect between when capital dollars for major projects are spent and SST is incurred, when those dollars go into rate base and affect rates, and given the relatively minor impact of the capital-related SST on the revenue requirement, there was no reasonable basis to vary from the four year average methodology.

The Terasen Utilities propose that each of the resulting revenue requirement impacts, by year, will be placed into the Tax Variance Deferral Account. This will result in an estimated amount of $1.643 million in the Tax Variance Deferral Account ($1.480 million for TGI (excluding Fort Nelson), $162 thousand for TGVI and $2 thousand for TGW) related to the SST savings. A summary of the calculations and amounts are provided by utility in Appendix A.

The amounts recorded in the Tax Variance Deferral Accounts will be returned to customers as part of the 2012 Revenue Requirements filings, net of the actual costs of implementing the HST changes in the Customer Information System ("CIS") and SAP – currently estimated at $295 thousand pre-tax, and allocated to the utilities based on the number of customers. The table below summarizes the net amounts expected to be returned to customers.

	Amounts in $ thousands			
Summary of HST Analysis	TGI	TGVI	TGW	Total
2010 Estimate	485	48	1	533
2011 Estimate	995	114	1	1,110
Total Revenue Requirement Impact of HST	**1,480**	**162**	**2**	**1,643**
Accenture Billing System Changes	(134)	(16)	(1)	(150)
Tax Consulting	(13)	(2)	(0)	(15)
IT Consulting re System Changes	(116)	(14)	(1)	(130)
Tax on above items	75	9	(0)	84
Total Costs of Implementing HST net of tax	(188)	(22)	(2)	(211)
Total to be Returned to Customers	**1,292**	**140**	**0**	**1,432**

Appendix A

HST FOR DEFERRAL

TGI Summary of HST Savings for 2010 and 2011 Revenue Requirements

Line No.	Particulars	Actual SST Paid by Year 2006	2007	2008	2009	4 Yr Average	PST Savings Estimates * 2010	2011	Methodology to Determine 2010 and 2011 Estimates of PST Savings
		Amounts in $ thousands							
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	O&M	647	643	713	779	695	365	612	O&M PST % applied to 2010 and 2011 O&M forecast by cost element
2	Meters	727	711	714	790	736	368	736	Four year average
3	Capital	1,116	1,236	1,609	1,972	1,483	742	1,483	Four year average
4	Total PST per SAP report	**2,490**	**2,590**	**3,036**	**3,541**	**2,914**	**1,474**	**2,830**	
5	PST on vehicle lease payments	194	186	171	181	183	55	110	Approx 40% subject to restricted input tax credit (vehicles under 3000 kg)
6	PST on vehicle operating costs	60	88	101	100	88	55	125	Vehicle Opex PST% applied to 2010 and 2011 Vehicle Opex forecast
7	PST on company use	15	14	17	10	14	-	-	N/A - subject to restricted input tax credit
8	PST on station heaters	88	76	89	49	75	-	-	N/A - subject to restricted input tax credit
9	Motor fuel tax	105	170	190	180	161	-	-	N/A - unaffected by HST implementation
10	ICE levy	-	2	5	5	3	2	3	Four year average
11	Less: HST applicable to meals & entertainment						(46)	(94)	Calculated as 7% of 2010 and 2011 meals & entertainment forecast
12	**Total SST remitted (2007/2008 per BCUC IR 1.143.1)**	**2,951**	**3,126**	**3,610**	**4,066**	**3,438**	**1,540**	**2,974**	
13									
14	* 2010 July to December only								
15									
16	Revenue Requirement Impact ($000s)						Revenue Req. Impact		
17	O&M (Rows 1, 5, 6, 10, 11)						431	755	
18	Depreciation Expense (related to Rows 2 and 3)						20	80	
19	Earned Return (related to Rows 2 and 3)						33	151	
20	Income Tax Expense (related to Rows 2 and 3)						1	9	
21	**Revenue Requirement Impact ($000s)**						485	995	

TGVI Summary of HST Savings for 2010 and 2011 Revenue Requirements

Amounts in $ thousands

Line No.	Particulars	Actual SST Paid by Year 2006	2007	2008	2009	4 Yr Average	PST Savings Estimates * 2010	2011	Methodology to Determine 2010 and 2011 Estimates of PST Savings
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	O&M	68	59	130	46	76	46	94	O&M PST % applied to 2010 and 2011 O&M forecast by cost element
2	Meters	38	4	39	3	21	10	21	Four year average
3	Capital	423	330	175	247	294	147	294	Four year average
4	Total PST per SAP report	**529**	**393**	**345**	**296**	**391**	**203**	**409**	
5	PST on company use	1	1	2	1	1	-	-	N/A - subject to restricted input tax credit
6	Motor fuel tax	460	656	607	567	573	-	-	N/A - unaffected by HST implementation
7	Less: HST applicable to meals & entertainment						(4)	(9)	
8	**Total SST remitted (2007/2008 per BCUC IR 1.106.1)**	**990**	**1,050**	**954**	**864**	**964**	**199**	**400**	
9									
10	* 2010 July to December only								
11									
12	Revenue Requirement Impact ($000s)						Revenue Req. Impact		
13	O&M (Rows 1 and 7)						42	85	
14	Depreciation Expense (related to Rows 2 and 3)						2	8	
15	Earned Return (related to Rows 2 and 3)						5	21	
16	Income Tax Expense (related to Rows 2 and 3)						(0)	(1)	
17	**Revenue Requirement Impact ($000s)**						48	114	

TGW Summary of HST Savings for 2010 and 2011 Revenue Requirements

		Amounts in $ thousands							
Line		Actual SST Paid by Year					PST Savings Estimates *		
No.	Particulars	2006	2007	2008	2009	Average	2010	2011	Methodology to Determine 2010 and 2011 Estimates of PST Savings
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
1	O&M	0	0	1	2	1	1	1	Four year average
2	Meters	-	-	-	1	0	0	0	Four year average
3	Capital	2	2	2	105	2	1	2	Three year average (2009 not representative due to conversion project)
4	Total PST per SAP report	**2**	**2**	**3**	**107**	**3**	**2**	**3**	
5	PST on company use	4	4	5	5	4	-	-	N/A - subject to restricted input tax credit
6	**Total SST remitted (2008 per BCUC IR 1.10.3)**	**7**	**6**	**8**	**112**	**7**	**2**	**3**	
7									
8	* 2010 July to December only								
9									
10									
11	Revenue Requirement Impact ($000s)						Revenue Req. Impact		
12	O&M (Row 1)						1	1	
13	Depreciation Expense (related to Rows 2 and 3)						0	0	
14	Earned Return (related to Rows 2 and 3)						- 0	0	
15	Income Tax Expense (related to Rows 2 and 3)						- 0	- 0	
16	**Revenue Requirement Impact ($000s)**						1	1	

Appendix G

SUMMARY FINANCIAL SCHEDULES

APPENDIX G: FINANCIAL SCHEDULES

1 FEI 2015-2018 FORMULA FINANCIAL SCHEDULES

	Schedule #
Summary of Rate Change Required – 2015 to 2018	1
Summary of Revenue Requirement Increase – 2015	2
Utility Income and Earned Return – 2015	3
Income Taxes – 2015	4
Utility Rate Base – 2015	5
Return on Capital – 2015	6
Summary of Revenue Requirement Increase – 2016	7
Utility Income and Earned Return – 2016	8
Income Taxes – 2016	9
Utility Rate Base – 2016	10
Return on Capital – 2016	11
Summary of Revenue Requirement Increase – 2017	12
Utility Income and Earned Return – 2017	13
Income Taxes – 2017	14
Utility Rate Base – 2017	15
Return on Capital – 2017	16
Summary of Revenue Requirement Increase – 2018	17
Utility Income and Earned Return – 2018	18
Income Taxes – 2018	19
Utility Rate Base – 2018	20
Return on Capital – 2018	21

2 FEI 2013-2018 FORECAST FINANCIAL SCHEDULES

	Schedule #
Summary of Rate Change Required - 2014	1
Summary of Revenue Requirement Increase - 2014	2
Utility Income and Earned Return – 2013	3
Utility Income and Earned Return – 2014	4
Gas Sales and Transportation Volumes – 2013	5
Gas Sales and Transportation Volumes – 2014	6
Revenue – 2013	7
Revenue – 2014	8
Cost of Gas – 2013/2014	9
Revenue under existing 2013 Rates and Revised 2014 Rates (Non-Bypass)	10
Revenue under existing 2013 Rates and Revised 2014 Rates (Bypass)	11
Other Operating Revenue – 2013	12
Other Operating Revenue – 2014	13
Operation & Maintenance Expenses - Resource View – 2013/2014	14
Operation & Maintenance Expenses - Activity View – 2013/2014	15
Operation & Maintenance Expenses - Activity View – 2013/2014 (Continued)	16
Operation & Maintenance Expenses - Activity View – 2013/2014 (Continued)	17
Property and Sundry Taxes – 2013	18

Summary of Rate Change

June 10, 2013

Appendix G-1
FORMULA
Schedule 1

Line No.	Particulars	2014 ($ Millions)		2015 Incremental ($ Millions)		2015 Cumulative ($ Millions)		2016 Incremental ($ Millions)		2016 Cumulative ($ Millions)		2017 Incremental ($ Millions)		2017 Cumulative ($ Millions)		2018 Incremental ($ Millions)		2018 Cumulative ($ Millions)		Cross Reference
1	(1)	(2)		(3)		(4)		(5)		(6)		(7)		(8)		(9)		(10)		(11)
2	Volume/Revenue Related																			
3	Customer Growth and Use Rates	(10.8)		(4.8)		(15.6)		(4.8)		(20.4)		(4.7)		(25.2)		(3.1)		(28.3)		
4	Change in Other Revenue	1.2	(9.6)	(0.7)	(5.5)	0.5	(15.1)	(0.4)	(5.2)	0.1	(20.3)	(0.3)	(5.0)	(0.1)	(25.3)	(0.1)	(3.2)	(0.2)	(28.5)	
5																				
6	O&M Changes																			
7	Gross O&M Increases	(0.8)		4.5		3.8		4.5		8.3		4.9		13.2		6.2		19.4		
8	Less: Capitalized Overhead	0.1	(0.7)	(0.6)	3.9	(0.5)	3.3	(0.6)	3.8	(1.2)	7.1	(0.7)	4.2	(1.8)	11.3	(0.9)	5.3	(2.7)	16.7	
9																				
10	Depreciation Expense																			
11	Change in Depreciation Rates	(0.1)		1.8		1.7		1.7		3.4		0.1		3.5		0.8		4.3		
12	Tax Expense Impact of Depreciation Changes	0.3		2.1		2.4		2.1		4.5		1.5		5.9		1.8		7.8		
13	Depreciation from Net Additions	1.0	1.2	4.4	8.2	5.4	9.4	4.7	8.5	10.1	17.9	4.3	5.9	14.4	23.8	4.7	7.4	19.1	31.2	
14																				
15	Amortization Expense																			
16		0.2		0.3		0.5		0.1		0.5		0.2		0.7		0.2		0.9		
17	Deferral Accounts	4.6	4.8	1.0	1.3	5.7	6.2	3.7	3.8	9.4	9.9	1.9	2.0	11.3	11.9	1.8	2.0	13.1	14.0	
18																				
19	Other																			
20	Property and Other Taxes	(2.4)		0.5		(1.9)		1.3		(0.6)		1.0		0.4		1.1		1.5		
21	Other (NSP Provision)	-		-		-		-		-		-		-		-		-		
22	Income Tax Rate Change	-		-		-		-		-		-		-		-		-		
23	Other Income Tax Changes	8.5		(1.2)		7.2		0.4		7.7		0.4		8.0		0.1		8.1		
24	Financing Rate Changes	(11.3)		(0.5)		(11.7)		(3.0)		(14.7)		(8.1)		(22.8)		(0.8)		(23.6)		
25	Financing Changes	(2.2)		1.3		(0.9)		1.1		0.1		4.3		4.4		3.9		8.3		
26	Rate Base Growth	1.0	(6.4)	1.9	2.0	3.0	(4.4)	1.7	1.5	4.7	(2.9)	1.2	(1.3)	5.8	(4.2)	0.9	5.2	6.7	1.0	
27																				
28	**Revenue Deficiency (Surplus)**		**(10.6)**				**(0.6)**				**11.7**				**17.6**				**34.3**	
29	Cross Reference						- Appendix G-1 FORMULA Sch 2				- Appendix G-1 FORMULA Sch 7				- Appendix G-1 FORMULA Sch 12				- Appendix G-1 FORMULA Sch 17	
30																				

FORTISBC ENERGY INC.

June 10, 2013

Appendix G-1
FORMULA
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Non-Bypass Sales	2015 Non-Bypass Transportation	2015 Bypass and Special Rates	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,127,236	$ 1,031,709	$ 86,853	$ 11,524	$ 1,130,086	$ 2,850	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,138	-	-	18,148	18,148	10	
8								
9	Total Revenue	1,145,374	1,031,709	86,853	29,672	1,148,234	2,860	
10								
11	Less - Cost of Gas	(499,685)	(497,198)	(253)	(249)	(497,700)	1,985	
12								
13	Gross Margin	$ 645,689	$ 534,511	$ 86,600	$ 29,423	$ 650,534	$ 4,845	
14								
15	Revenue Deficiency (Surplus)	$ (10,612)	$ (558)	$ (90)	$ -	**$ (648)**	$ 9,964	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	-1.64%	-0.10%	-0.10%	0.00%	-0.10%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	-0.93%	-0.05%	-0.10%	0.00%	-0.06%		
20								

FORTISBC ENERGY INC. | June 10, 2013 | Appendix G-1 FORMULA Schedule 3

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars (1)	2014 FORECAST (2)	2015 Existing 2013 Rates (3)	2015 Revised Revenue (4)	2015 Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	114,985	115,590	-	115,590	605	
3	Transportation	98,582	99,707	-	99,707	1,125	
4		213,567	215,297	-	215,297	1,730	
5							
6	Average Rate per GJ						
7	Sales	$8.885	$8.926	$0.000	$8.921	$0.036	
8	Transportation	$0.964	$0.987	$0.000	$0.986	$0.022	
9	Average	$5.228	$5.249	$0.000	$5.246	$0.018	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,030,748	$ 1,031,709	$ -	$ 1,031,709	$ 961	
13	- Increase / (Decrease)	(9,154)	-	(558)	(558)	8,596	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	96,488	98,377	-	98,377	1,889	
16	- Increase / (Decrease)	(1,458)		(90)	(90)	1,368	
17							
18	**Total Revenue**	1,116,624	1,130,086	(648)	1,129,438	12,814	
19							
20	Cost of Gas Sold (Including Gas Lost)	499,685	497,700	-	497,700	(1,985)	
21							
22	**Gross Margin**	616,939	632,386	(648)	631,738	14,799	
23							
24	Operation and Maintenance	202,307	206,218	-	206,218	3,911	
25	Property and Sundry Taxes	48,797	49,335	-	49,335	538	
26	Depreciation and Amortization	148,655	156,147	-	156,147	7,492	
27	Other Operating Revenue	(23,616)	(24,289)	-	(24,289)	(673)	
28	Sub-total	376,143	387,411	-	387,411	11,268	
29	Utility Income Before Income Taxes	240,796	244,975	(648)	244,327	3,531	
30							
31	Income Taxes	36,828	37,810	(162)	37,648	820	
32							
33	**EARNED RETURN**	$ 203,968	$ 207,165	$ (486)	$ 206,679	$ 2,711	- Appendix G-1 FORMULA Sch 6
34							
35							
36	**UTILITY RATE BASE**	$ 2,798,597	$ 2,855,424	$ (2)	$ 2,855,422	$ 56,825	- Appendix G-1 FORMULA Sch 5
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.29%	7.26%		7.24%	-0.05%	- Appendix G-1 FORMULA Sch 6

FORTISBC ENERGY INC.

June 10, 2013

Appendix G-1
FORMULA
Schedule 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars (1)	2014 FORECAST (2)	2015 Existing 2013 Rates (3)	2015 Revised Revenue (4)	2015 Total (5)	Change (6)	Cross Reference (7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 203,968	$ 207,165	$ (486)	$ 206,679	$ 2,711	- Appendix G-1 FORMULA Sch 3
3	Deduct - Interest on Debt	(109,690)	(110,487)	-	(110,487)	(797)	- Appendix G-1 FORMULA Sch 6
4	Add (Deduct) - Permanent & Timing Differences	16,206	16,751	-	16,751	545	
5	Adjusted Taxable Income After Tax	$ 110,484	113,429	(486)	$ 112,943	2,459	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 147,312	$ 151,239	$ (648)	$ 150,591	$ 3,279	
11							
12							
13	Income Tax - Current	$ 36,828	$ 37,810	$ (162)	$ 37,648	$ 820	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 36,828	$ 37,810	$ (162)	$ 37,648	$ 820	- Appendix G-1 FORMULA Sch 3
17							

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 5

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Adjustments	2015 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,870,159	$ 4,008,286	$ -	$ 4,008,286	$ 138,127	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,008,286	4,155,222	-	4,155,222	146,936	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,105,308)	$ (1,206,067)	$ -	$ (1,206,067)	$ (100,759)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,206,067)	(1,317,220)	-	(1,317,220)	(111,153)	
8							
9	CIAC, Beginning	$ (194,421)	$ (196,276)	$ -	$ (196,276)	$ (1,855)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(196,276)	(200,325)	-	(200,325)	(4,049)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 57,362	$ 59,914	$ -	$ 59,914	$ 2,552	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	59,914	64,203	-	64,203	4,289	
16							
17	Net Plant in Service, Mid-Year	$ 2,646,825	$ 2,683,869	$ -	$ 2,683,869	$ 37,044	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	47,872	65,525	-	65,525	17,653	
22	Cash Working Capital	(276)	23	(2)	21	297	
23	Other Working Capital	79,039	80,704	-	80,704	1,665	
24	Deferred Income Taxes Regulatory Asset	288,453	287,980	-	287,980	(473)	
25	Deferred Income Taxes Regulatory Liability	(288,453)	(287,980)	-	(287,980)	473	
26	LILO Benefit	(983)	(817)	-	(817)	166	
27	**Utility Rate Base**	$ 2,798,597	$ 2,855,424	$ (2)	$ 2,855,422	$ 56,825	- Appendix G-1 FORMULA Sch 6

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1
FORMULA
Schedule 6

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2015 AT 2013 RATES							
2	Long-Term Debt		$ 1,559,314	54.61%	6.77%	3.70%		
3	Unfunded Debt		196,772	6.89%	2.50%	0.17%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,099,338	38.50%	8.79%	3.39%		
6								
7			$ 2,855,424	100.00%		7.26%		- Appendix G-1 FORMULA Sch 5
8								
9	2015 REVISED RATES							
10	Long-Term Debt		$ 1,559,314	54.61%	6.77%	3.70%	$ 105,568	
11	Unfunded Debt	$ 196,772						
12	Adjustment, Revised Rates	(1)	196,771	6.89%	2.50%	0.17%	4,919	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,099,337	38.50%	8.75%	3.37%	96,192	
15								- Appendix G-1 FORMULA Sch 3
16			$ 2,855,422	100.00%		7.24%	$ 206,679	- Appendix G-1 FORMULA Sch 5
17								
18	2014 REVISED RATES							
19	Long-Term Debt		$ 1,564,198	55.89%	6.84%	3.82%	$ 106,944	
20	Unfunded Debt	$ 156,956						
21	Adjustment, Revised Rates	(17)	156,939	5.61%	1.75%	0.10%	2,746	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,077,460	38.50%	8.75%	3.37%	94,278	
24								
25			$ 2,798,597	100.00%		7.29%	$ 203,968	
26								
27	CHANGE FROM 2014 REVISED RATES							
28	Long-Term Debt		$ (4,884)	-1.28%	-0.07%	-0.12%	$ (1,376)	
29	Unfunded Debt	$ 39,816						
30	Adjustment, Revised Rates	16	39,832	1.28%	0.75%	0.07%	2,173	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		21,877	0.00%	0.00%	0.00%	1,914	
33								
34			$ 56,825	0.00%		-0.05%	$ 2,711	

FORTISBC ENERGY INC.

June 10, 2013

Appendix G-1
FORMULA
Schedule 7

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Non-Bypass Sales	2016 Non-Bypass Transportation	2016 Bypass and Special Rates	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,130,086	$ 1,037,604	$ 88,775	$ 11,524	$ 1,137,903	$ 7,817	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,148	-	-	18,159	18,159	11	
8								
9	Total Revenue	1,148,234	1,037,604	88,775	29,683	1,156,062	7,828	
10								
11	Less - Cost of Gas	(497,700)	(500,169)	(255)	(252)	(500,676)	(2,976)	
12								
13	Gross Margin	$ 650,534	$ 537,435	$ 88,520	$ 29,431	$ 655,386	$ 4,852	
14								
15	Revenue Deficiency (Surplus)	$ (648)	$ 10,081	$ 1,661	$ -	**$ 11,742**	$ 12,390	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	-0.10%	1.88%	1.88%	0.00%	1.79%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	-0.06%	0.97%	1.87%	0.00%	1.02%		
20								

FORTISBC ENERGY INC.

June 10, 2013

Appendix G-1
FORMULA
Schedule 8

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,590	116,182	-	116,182	592	
3	Transportation	99,707	100,620	-	100,620	913	
4		215,297	216,802	-	216,802	1,505	
5							
6	Average Rate per GJ						
7	Sales	$8.921	$8.931	$0.000	$9.018	$0.097	
8	Transportation	$0.986	$0.997	$0.000	$1.013	$0.027	
9	Average	$5.246	$5.249	$0.000	$5.303	$0.057	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,031,709	$ 1,037,604	$ -	$ 1,037,604	$ 5,895	
13	- Increase / (Decrease)	(558)	-	10,082	10,082	10,640	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	98,377	100,299	-	100,299	1,922	
16	- Increase / (Decrease)	(90)		1,660	1,660	1,750	
17							
18	**Total Revenue**	1,129,438	1,137,903	11,742	1,149,645	20,207	
19							
20	Cost of Gas Sold (Including Gas Lost)	497,700	500,676	-	500,676	2,976	
21							
22	**Gross Margin**	631,738	637,227	11,742	648,969	17,231	
23							
24	Operation and Maintenance	206,218	210,067	-	210,067	3,849	
25	Property and Sundry Taxes	49,335	50,614	-	50,614	1,279	
26	Depreciation and Amortization	156,147	166,273	-	166,273	10,126	
27	Other Operating Revenue	(24,289)	(24,642)	-	(24,642)	(353)	
28	Sub-total	387,411	402,312	-	402,312	14,901	
29	Utility Income Before Income Taxes	244,327	234,915	11,742	246,657	2,330	
30							
31	Income Taxes	37,648	37,239	2,935	40,174	2,526	
32							
33	**EARNED RETURN**	$ 206,679	$ 197,676	$ 8,807	$ 206,483	$ (196)	- Appendix G-1 FORMULA Sch 11
34							
35							
36	**UTILITY RATE BASE**	$ 2,855,422	$ 2,905,870	$ 33	$ 2,905,903	$ 50,481	- Appendix G-1 FORMULA Sch 10
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.24%	6.80%		7.11%	-0.13%	- Appendix G-1 FORMULA Sch 11

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 9

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 206,679	$ 197,676	$ 8,807	$ 206,483	$ (196)	- Appendix G-1 FORMULA Sch 8
3	Deduct - Interest on Debt	(110,487)	(108,589)	(1)	(108,590)	1,897	- Appendix G-1 FORMULA Sch 11
4	Add (Deduct) - Permanent & Timing Differences	16,751	22,630	-	22,630	5,879	
5	Adjusted Taxable Income After Tax	$ 112,943	111,717	8,806	$ 120,523	7,580	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 150,591	$ 148,956	$ 11,741	$ 160,697	$ 10,106	
11							
12							
13	Income Tax - Current	$ 37,648	$ 37,239	$ 2,935	$ 40,174	$ 2,526	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 37,648	$ 37,239	$ 2,935	$ 40,174	$ 2,526	- Appendix G-1 FORMULA Sch 8
17							

FORTISBC ENERGY INC.

June 10, 2013

Appendix G-1
FORMULA
Schedule 10

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Adjustments	2016 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,008,286	$ 4,155,222	$ -	$ 4,155,222	$ 146,936	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,155,222	4,289,032	-	4,289,032	133,810	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,206,067)	$ (1,317,220)	$ -	$ (1,317,220)	$ (111,153)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,317,220)	(1,417,579)	-	(1,417,579)	(100,359)	
8							
9	CIAC, Beginning	$ (196,276)	$ (200,325)	$ -	$ (200,325)	$ (4,049)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(200,325)	(203,697)	-	(203,697)	(3,372)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 59,914	$ 64,203	$ -	$ 64,203	$ 4,289	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	64,203	67,620	-	67,620	3,417	
16							
17	Net Plant in Service, Mid-Year	$ 2,683,869	$ 2,718,628	$ -	$ 2,718,628	$ 34,760	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	65,525	76,680	-	76,680	11,155	
22	Cash Working Capital	21	434	33	467	446	
23	Other Working Capital	80,704	84,659	-	84,659	3,955	
24	Deferred Income Taxes Regulatory Asset	287,980	287,029	-	287,029	(951)	
25	Deferred Income Taxes Regulatory Liability	(287,980)	(287,029)	-	(287,029)	951	
26	LILO Benefit	(817)	(651)	-	(651)	166	
27	**Utility Rate Base**	$ 2,855,422	$ 2,905,870	$ 33	$ 2,905,903	$ 50,482	- Appendix G-1 FORMULA Sch 11

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1

FORMULA

RETURN ON CAPITAL

Schedule 11

FOR THE YEAR ENDING DECEMBER 31, 2016

($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2016 AT 2013 RATES							
2	Long-Term Debt		$ 1,556,112	53.55%	6.50%	3.48%		
3	Unfunded Debt		230,998	7.95%	3.25%	0.26%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,118,760	38.50%	7.96%	3.06%		
6								
7			$ 2,905,870	100.00%		6.80%		- Appendix G-1 FORMULA Sch 10
8								
9	2016 REVISED RATES							
10	Long-Term Debt		$ 1,556,112	53.55%	6.50%	3.48%	$ 101,082	
11	Unfunded Debt	$ 230,998						
12	Adjustment, Revised Rates	20	231,018	7.95%	3.25%	0.26%	7,508	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,118,773	38.50%	8.75%	3.37%	97,893	
15								- Appendix G-1 FORMULA Sch 8
16			$ 2,905,903	100.00%		7.11%	$ 206,483	- Appendix G-1 FORMULA Sch 10
17								
18	2015 REVISED RATES							
19	Long-Term Debt		$ 1,559,314	54.61%	6.77%	3.70%	$ 105,568	
20	Unfunded Debt	$ 196,772						
21	Adjustment, Revised Rates	(1)	196,771	6.89%	2.50%	0.17%	4,919	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,099,337	38.50%	8.75%	3.37%	96,192	
24								
25			$ 2,855,422	100.00%		7.24%	$ 206,679	- Appendix G-1 FORMULA Sch 6
26								
27	CHANGE FROM 2015 REVISED RATES							
28	Long-Term Debt		$ (3,202)	-1.06%	-0.27%	-0.22%	$ (4,486)	
29	Unfunded Debt	$ 34,226						
30	Adjustment, Revised Rates	21	34,247	1.06%	0.75%	0.09%	2,589	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		19,436	0.00%	0.00%	0.00%	1,701	
33								
34			$ 50,481	0.00%		-0.13%	$ (196)	

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Non-Bypass Sales	2017 Non-Bypass Transportation	2017 Bypass and Special Rates	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,137,903	$ 1,043,557	$ 90,727	$ 11,525	$ 1,145,809	$ 7,906	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,159	-	-	18,160	18,160	1	
8								
9	Total Revenue	1,156,062	1,043,557	90,727	29,685	1,163,969	7,907	
10								
11	Less - Cost of Gas	(500,676)	(503,353)	(259)	(253)	(503,865)	(3,189)	
12								
13	Gross Margin	$ 655,386	$ 540,204	$ 90,468	$ 29,432	$ 660,104	$ 4,718	
14								
15	Revenue Deficiency (Surplus)	$ 11,742	$ 15,033	$ 2,517	$ -	**$ 17,550**	$ 5,808	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	1.79%	2.78%	2.78%	0.00%	2.66%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.02%	1.44%	2.77%	0.00%	1.51%		
20								

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 13

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars (1)	2016 FORECAST (2)	2017 Existing 2013 Rates (3)	2017 Revised Revenue (4)	2017 Total (5)	Change (6)	Cross Reference (7)
1	ENERGY VOLUMES (TJ)						
2	Sales	116,182	116,735	-	116,735	553	
3	Transportation	100,620	101,629	-	101,629	1,009	
4		216,802	218,364	-	218,364	1,562	
5							
6	Average Rate per GJ						
7	Sales	$9.018	$8.940	$0.000	$9.068	$0.050	
8	Transportation	$1.013	$1.006	$0.000	$1.031	$0.018	
9	Average	$5.303	$5.247	$0.000	$5.328	$0.025	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,037,604	$ 1,043,557	$ -	$ 1,043,557	$ 5,953	
13	- Increase / (Decrease)	10,082	-	15,031	15,031	4,949	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	100,299	102,253	-	102,253	1,954	
16	- Increase / (Decrease)	1,660		2,519	2,519	859	
17							
18	**Total Revenue**	1,149,645	1,145,810	17,550	1,163,360	13,715	
19							
20	Cost of Gas Sold (Including Gas Lost)	500,676	503,865	-	503,865	3,189	
21							
22	**Gross Margin**	648,969	641,945	17,550	659,495	10,526	
23							
24	Operation and Maintenance	210,067	214,304	-	214,304	4,237	
25	Property and Sundry Taxes	50,614	51,598	-	51,598	984	
26	Depreciation and Amortization	166,273	172,701	-	172,701	6,428	
27	Other Operating Revenue	(24,642)	(24,916)	-	(24,916)	(274)	
28	Sub-total	402,312	413,687	-	413,687	11,375	
29	Utility Income Before Income Taxes	246,657	228,258	17,550	245,808	(849)	
30							
31	Income Taxes	40,174	37,625	4,386	42,011	1,837	
32							
33	**EARNED RETURN**	$ 206,483	$ 190,633	$ 13,164	$ 203,797	$ (2,686)	- Appendix G-1 FORMULA Sch 16
34							
35							
36	**UTILITY RATE BASE**	$ 2,905,903	$ 2,940,249	$ 325	$ 2,940,574	$ 34,671	- Appendix G-1 FORMULA Sch 15
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.11%	6.48%		6.93%	-0.18%	- Appendix G-1 FORMULA Sch 16

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 14

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Revised Revenue	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 206,483	$ 190,633	$ 13,164	$ 203,797	$ (2,686)	- Appendix G-1 FORMULA Sch 13
3	Deduct - Interest on Debt	(108,590)	(104,728)	(8)	(104,736)	3,854	- Appendix G-1 FORMULA Sch 16
4	Add (Deduct) - Permanent & Timing Differences	22,630	26,971	-	26,971	4,341	
5	Adjusted Taxable Income After Tax	$ 120,523	112,876	13,156	$ 126,032	5,509	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 160,697	$ 150,501	$ 17,541	$ 168,043	$ 7,346	
11							
12							
13	Income Tax - Current	$ 40,174	$ 37,625	$ 4,385	$ 42,011	$ 1,837	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 40,174	$ 37,625	$ 4,385	$ 42,011	$ 1,837	- Appendix G-1 FORMULA Sch 13
17							

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 15

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Adjustments	2017 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,155,222	$ 4,289,032	$ -	$ 4,289,032	$ 133,810	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,289,032	4,437,027	-	4,437,027	147,995	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,317,220)	$ (1,417,579)	$ -	$ (1,417,579)	$ (100,359)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,417,579)	(1,532,604)	-	(1,532,604)	(115,025)	
8							
9	CIAC, Beginning	$ (200,325)	$ (203,697)	$ -	$ (203,697)	$ (3,372)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(203,697)	(206,836)	-	(206,836)	(3,139)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 64,203	$ 67,620	$ -	$ 67,620	$ 3,417	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	67,620	70,505	-	70,505	2,885	
16							
17	Net Plant in Service, Mid-Year	$ 2,718,628	$ 2,751,734	$ -	$ 2,751,734	$ 33,106	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	76,680	71,989	-	71,989	(4,691)	
22	Cash Working Capital	467	380	325	705	238	
23	Other Working Capital	84,659	90,511	-	90,511	5,852	
24	Deferred Income Taxes Regulatory Asset	287,029	285,481	-	285,481	(1,548)	
25	Deferred Income Taxes Regulatory Liability	(287,029)	(285,481)	-	(285,481)	1,548	
26	LILO Benefit	(651)	(485)	-	(485)	166	
27	**Utility Rate Base**	$ 2,905,903	$ 2,940,249	$ 325	$ 2,940,574	$ 34,671	- Appendix G-1 FORMULA Sch 16

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 16

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2017 AT 2013 RATES							
2	Long-Term Debt		$ 1,653,956	56.25%	5.98%	3.36%		
3	Unfunded Debt		154,297	5.25%	3.75%	0.20%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,131,996	38.50%	7.59%	2.92%		
6								
7			$ 2,940,249	100.00%		6.48%		- Appendix G-1 FORMULA Sch 15
8								
9	2017 REVISED RATES							
10	Long-Term Debt		$ 1,653,956	56.25%	5.98%	3.36%	$ 98,942	
11	Unfunded Debt	$ 154,297						
12	Adjustment, Revised Rates	200	154,497	5.25%	3.75%	0.20%	5,794	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,132,121	38.50%	8.75%	3.37%	99,061	
15								- Appendix G-1 FORMULA Sch 13
16			$ 2,940,574	100.00%		6.93%	$ 203,797	- Appendix G-1 FORMULA Sch 15
17								
18	2016 REVISED RATES							
19	Long-Term Debt		$ 1,556,112	53.55%	6.50%	3.48%	$ 101,082	
20	Unfunded Debt	$ 230,998						
21	Adjustment, Revised Rates	20	231,018	7.95%	3.25%	0.26%	7,508	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,118,773	38.50%	8.75%	3.37%	97,893	
24								
25			$ 2,905,903	100.00%		7.11%	$ 206,483	- Appendix G-1 FORMULA Sch 11
26								
27	CHANGE FROM 2016 REVISED RATES							
28	Long-Term Debt		$ 97,844	2.70%	-0.52%	-0.12%	$ (2,140)	
29	Unfunded Debt	$ (76,701)						
30	Adjustment, Revised Rates	180	(76,521)	-2.70%	0.50%	-0.06%	(1,714)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		13,348	0.00%	0.00%	0.00%	1,168	
33								
34			$ 34,671	0.00%		-0.18%	$ (2,686)	

FORTISBC ENERGY INC.

June 10, 2013

Appendix G-1
FORMULA
Schedule 17

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Non-Bypass Sales	2018 Non-Bypass Transportation	2018 Bypass and Special Rates	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,145,809	$ 1,045,927	$ 92,694	$ 11,525	$ 1,150,146	$ 4,337	
5								
6	Add - Other Revenue Related to SCP Third Party + FEVI Wheeling							
7	Revenue	18,160	-	-	18,159	18,159	(1)	
8								
9	Total Revenue	1,163,969	1,045,927	92,694	29,684	1,168,305	4,336	
10								
11	Less - Cost of Gas	(503,865)	(504,563)	(262)	(255)	(505,080)	(1,215)	
12								
13	Gross Margin	$ 660,104	$ 541,364	$ 92,432	$ 29,429	$ 663,225	$ 3,121	
14								
15	Revenue Deficiency (Surplus)	$ 17,550	$ 29,299	$ 5,002	$ -	**$ 34,301**	$ 16,751	
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	2.66%	5.41%	5.41%	0.00%	5.17%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.51%	2.80%	5.40%	0.00%	2.94%		
20								

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 18

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	116,735	116,901	-	116,901	166	
3	Transportation	101,629	102,632	-	102,632	1,003	
4		218,364	219,533	-	219,533	1,169	
5							
6	Average Rate per GJ						
7	Sales	$9.068	$8.947	$0.000	$9.198	$0.130	
8	Transportation	$1.031	$1.015	$0.000	$1.064	$0.033	
9	Average	$5.328	$5.239	$0.000	$5.395	$0.067	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,043,557	$ 1,045,927	$ -	$ 1,045,927	$ 2,370	
13	- Increase / (Decrease)	15,031	-	29,298	29,298	14,267	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	102,253	104,220	-	104,220	1,967	
16	- Increase / (Decrease)	2,519		5,003	5,003	2,484	
17							
18	**Total Revenue**	1,163,360	1,150,147	34,301	1,184,448	21,088	
19							
20	Cost of Gas Sold (Including Gas Lost)	503,865	505,080	-	505,080	1,215	
21							
22	**Gross Margin**	659,495	645,067	34,301	679,368	19,873	
23							
24	Operation and Maintenance	214,304	219,618	-	219,618	5,314	
25	Property and Sundry Taxes	51,598	52,691	-	52,691	1,093	
26	Depreciation and Amortization	172,701	180,244	-	180,244	7,543	
27	Other Operating Revenue	(24,916)	(24,967)	-	(24,967)	(51)	
28	Sub-total	413,687	427,586	-	427,586	13,899	
29	Utility Income Before Income Taxes	245,808	217,481	34,301	251,782	5,974	
30							
31	Income Taxes	42,011	35,381	8,572	43,953	1,942	
32							
33	**EARNED RETURN**	$ 203,797	$ 182,100	$ 25,729	$ 207,829	$ 4,032	- Appendix G-1 FORMULA Sch 21
34							
35							
36	**UTILITY RATE BASE**	$ 2,940,574	$ 2,967,418	$ 395	$ 2,967,813	$ 27,239	- Appendix G-1 FORMULA Sch 20
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	6.93%	6.14%		7.00%	0.07%	- Appendix G-1 FORMULA Sch 21

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1
FORMULA
Schedule 19

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 203,797	$ 182,100	$ 25,729	$ 207,829	$ 4,032	- Appendix G-1 FORMULA Sch 18
3	Deduct - Interest on Debt	(104,736)	(107,840)	(11)	(107,851)	(3,115)	- Appendix G-1 FORMULA Sch 21
4	Add (Deduct) - Permanent & Timing Differences	26,971	31,881	-	31,881	4,910	
5	Adjusted Taxable Income After Tax	$ 126,032	106,141	25,718	$ 131,859	5,827	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 168,043	$ 141,521	$ 34,291	$ 175,812	$ 7,769	
11							
12							
13	Income Tax - Current	$ 42,011	$ 35,380	$ 8,573	$ 43,953	$ 1,942	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 42,011	$ 35,380	$ 8,573	$ 43,953	$ 1,942	- Appendix G-1 FORMULA Sch 18
17							

FORTISBC ENERGY INC. June 10, 2013 Appendix G-1 FORMULA Schedule 20

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Adjustments	2018 2013 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,289,032	$ 4,437,027	$ -	$ 4,437,027	$ 147,995	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,437,027	4,595,951	-	4,595,951	158,924	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,417,579)	$ (1,532,604)	$ -	$ (1,532,604)	$ (115,025)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,532,604)	(1,660,073)	-	(1,660,073)	(127,469)	
8							
9	CIAC, Beginning	$ (203,697)	$ (206,836)	$ -	$ (206,836)	$ (3,139)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(206,836)	(213,425)	-	(213,425)	(6,589)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 67,620	$ 70,505	$ -	$ 70,505	$ 2,885	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	70,505	76,498	-	76,498	5,993	
16							
17	Net Plant in Service, Mid-Year	$ 2,751,734	$ 2,783,522	$ -	$ 2,783,522	$ 31,788	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	71,989	61,155	-	61,155	(10,834)	
22	Cash Working Capital	705	259	395	654	(51)	
23	Other Working Capital	90,511	96,690	-	96,690	6,179	
24	Deferred Income Taxes Regulatory Asset	285,481	283,368	-	283,368	(2,113)	
25	Deferred Income Taxes Regulatory Liability	(285,481)	(283,368)	-	(283,368)	2,113	
26	LILO Benefit	(485)	(328)	-	(328)	157	
27	**Utility Rate Base**	$ 2,940,574	$ 2,967,418	$ 395	$ 2,967,813	$ 27,239	- Appendix G-1 FORMULA Sch 21

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2018 AT 2013 RATES							
2	Long-Term Debt		$ 1,752,739	59.07%	5.96%	3.52%		
3	Unfunded Debt		72,223	2.43%	4.75%	0.12%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,142,456	38.50%	6.50%	2.50%		
6								
7			$ 2,967,418	100.00%		6.14%		- Appendix G-1 FORMULA Sch 20
8								
9	2018 REVISED RATES							
10	Long-Term Debt		$ 1,752,739	59.06%	5.96%	3.52%	$ 104,409	
11	Unfunded Debt	$ 72,223						
12	Adjustment, Revised Rates	243	72,466	2.44%	4.75%	0.12%	3,442	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,142,608	38.50%	8.75%	3.37%	99,978	
15								- Appendix G-1 FORMULA Sch 18
16			$ 2,967,813	100.00%		7.00%	$ 207,829	- Appendix G-1 FORMULA Sch 20
17								
18	2017 REVISED RATES							
19	Long-Term Debt		$ 1,653,956	56.25%	5.98%	3.36%	$ 98,942	
20	Unfunded Debt	$ 154,297						
21	Adjustment, Revised Rates	200	154,497	5.25%	3.75%	0.20%	5,794	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,132,121	38.50%	8.75%	3.37%	99,061	
24								
25			$ 2,940,574	100.00%		6.93%	$ 203,797	- Appendix G-1 FORMULA Sch 16
26								
27	CHANGE FROM 2017 REVISED RATES							
28	Long-Term Debt		$ 98,783	2.81%	-0.02%	0.16%	$ 5,467	
29	Unfunded Debt	$ (82,074)						
30	Adjustment, Revised Rates	43	(82,031)	-2.81%	1.00%	-0.08%	(2,352)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		10,487	0.00%	0.00%	0.00%	917	
33								
34			$ 27,239	0.00%		0.08%	$ 4,032	

Summary of Rate Change June 10, 2013 Appendix G2 FORECAST Schedule 1

Line No.	Particulars	2014 ($ Millions)		Cross Reference
	(1)	(2)	(3)	(4)
1	Volume/Revenue Related			
2	Customer Growth and Use Rates	(10.8)		
3	Change in Other Revenue	1.2	(9.6)	
4				
5	O&M Changes			
6	Gross O&M Increases	3.9		
7	Less: Capitalized Overhead	(0.6)	3.4	
8				
9	Depreciation Expense			
10	Change in Depreciation Rates	(0.1)		
11	Tax Expense Impact of Depreciation Changes	0.3		
12	Depreciation from Net Additions	1.0	1.2	
13				
14	Amortization Expense			
15	CIAC	0.2		
16	Deferral Accounts	4.6	4.8	
17				
18	Property and Other Taxes	(2.4)		
19	Other (NSP Provision)	-		
20	Income Tax Rate Change	-		
21	Other Income Tax Changes	8.0		
22	Financing Rate Changes	(11.3)		
23	Financing Changes	(2.1)		
24	Rate Base Growth	1.1	(6.7)	
25				
26	**Revenue Deficiency (Surplus)**		**(6.9)**	- Appendix G2-FORECAST, Sch 2

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 2

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Non-Bypass Sales	2014 Non-Bypass Transportation	2014 Bypass and Special Rates	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,128,389	$ 1,030,748	$ 84,964	$ 11,524	$ 1,127,236	$ (1,153)	- Appendix G2-FORECAST, Sch 8
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,237	-	-	18,138	18,138	(99)	- Appendix G2-FORECAST, Sch 13
8								
9	Total Revenue	1,146,626	1,030,748	84,964	29,662	1,145,374	(1,252)	
10								
11	Less - Cost of Gas	(505,695)	(499,187)	(250)	(248)	(499,685)	6,010	- Appendix G2-FORECAST, Sch 9
12								
13	Gross Margin	$ 640,931	$ 531,561	$ 84,714	$ 29,414	$ 645,689	$ 4,758	
14								
15	Revenue Deficiency (Surplus)	$ -	$ (5,957)	$ (949)	$ -	**$ (6,906)**	$ (6,906)	- Appendix G2-FORECAST, Sch 1
16								- Appendix G2-FORECAST, Sch 62
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.00%	-1.12%	-1.12%	0.00%	-1.07%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.00%	-0.58%	-1.12%	0.00%	-0.60%		
20								

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
					(Column (4) - Column (3))	
1	ENERGY VOLUMES (TJ)					
2	Sales	113,621	112,327	113,946	1,619	- Appendix G2-FORECAST, Sch 5
3	Transportation	86,767	94,833	97,857	3,024	- Appendix G2-FORECAST, Sch 5
4		200,388	207,160	211,803	4,643	
5						
6	Average Rate per GJ					
7	Sales	$ 9.106	$ 10.538	$ 9.052	$ (1.486)	
8	Transportation	$ 1.039	$ 0.966	$ 0.991	$ 0.025	
9	Average	$ 5.616	$ 6.156	$ 5.296	$ (0.860)	
10						
11	UTILITY REVENUE					
12	Sales - Existing Rates	$ 1,034,629	$ 1,133,062	$ 1,031,439	$ (101,623)	- Appendix G2-FORECAST, Sch 7
13	- Increase / (Decrease)	-	50,679	-	(50,679)	
14	RSAM Revenue	472	-	(6,666)	(6,666)	
15	Transportation - Existing Rates	90,183	83,945	96,951	13,006	- Appendix G2-FORECAST, Sch 7
16	- Increase / (Decrease)	-	7,660	-	(7,660)	
17						
18	**Total Revenue**	1,125,284	1,275,346	1,121,724	(153,622)	
19						
20	Cost of Gas Sold (Including Gas Lost)	539,821	658,568	505,695	(152,873)	- Appendix G2-FORECAST, Sch 9
21						
22	**Gross Margin**	585,463	616,778	616,029	(749)	
23						
24	Operation and Maintenance	187,925	202,963	198,578	(4,385)	- Appendix G2-FORECAST, Sch 14
25	Property and Sundry Taxes	49,656	51,239	51,239	-	- Appendix G2-FORECAST, Sch 18
26	Depreciation and Amortization	123,928	142,912	142,912	-	- Appendix G2-FORECAST, Sch 20
27	Other Operating Revenue	(24,501)	(24,789)	(23,204)	1,585	- Appendix G2-FORECAST, Sch 12
28	Sub-total	337,008	372,325	369,525	(2,800)	
29	Utility Income Before Income Taxes	248,454	244,453	246,504	2,051	
30						
31	Income Taxes	26,880	28,049	27,508	(541)	- Appendix G2-FORECAST, Sch 22
32						
33	**EARNED RETURN**	$ 221,574	$ 216,404	$ 218,996	$ 2,592	- Appendix G2-FORECAST, Sch 57
34						
35						
36	**UTILITY RATE BASE**	$ 2,692,824	$ 2,767,988	$ 2,701,542	$ (66,446)	- Appendix G2-FORECAST, Sch 28
37						
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.23%	7.82%	8.11%	0.29%	- Appendix G2-FORECAST, Sch 57

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 4

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	Revised Revenue	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	113,946	114,985	-	114,985	1,039	- Appendix G2-FORECAST, Sch 6
3	Transportation	97,857	98,582	-	98,582	725	- Appendix G2-FORECAST, Sch 6
4		211,803	213,567	-	213,567	1,764	
5							
6	Average Rate per GJ						
7	Sales	$ 9.052	$ 8.964	$ -	$ 8.912	$ (0.140)	
8	Transportation	$ 0.991	$ 0.979	$ -	$ 0.969	$ (0.022)	
9	Average	$ 5.296	$ 5.278	$ -	$ 5.246	$ (0.050)	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,031,439	$ 1,030,748	$ -	$ 1,030,748	$ (691)	- Appendix G2-FORECAST, Sch 8
13	- Increase / (Decrease)	-	-	(5,956)	(5,956)	(5,956)	- Appendix G2-FORECAST, Sch 10
14	RSAM Revenue	(6,666)				6,666	
15	Transportation - Existing Rates	96,951	96,488	-	96,488	(463)	- Appendix G2-FORECAST, Sch 8
16	- Increase / (Decrease)	-		(950)	(950)	(950)	- Appendix G2-FORECAST, Sch 10
17							
18	**Total Revenue**	1,121,724	1,127,236	(6,906)	1,120,330	(1,394)	
19							
20	Cost of Gas Sold (Including Gas Lost)	505,695	499,685	-	499,685	(6,010)	- Appendix G2-FORECAST, Sch 9
21							
22	**Gross Margin**	616,029	627,551	(6,906)	620,645	4,616	
23							
24	Operation and Maintenance	198,578	206,343	-	206,343	7,765	- Appendix G2-FORECAST, Sch 14
25	Property and Sundry Taxes	51,239	48,797	-	48,797	(2,442)	- Appendix G2-FORECAST, Sch 19
26	Depreciation and Amortization	142,912	148,655	-	148,655	5,743	- Appendix G2-FORECAST, Sch 21
27	Other Operating Revenue	(23,204)	(23,616)	-	(23,616)	(412)	- Appendix G2-FORECAST, Sch 13
28	Sub-total	369,525	380,179	-	380,179	10,654	
29	Utility Income Before Income Taxes	246,504	247,372	(6,906)	240,466	(6,038)	
30							
31	Income Taxes	27,508	38,100	(1,727)	36,373	8,865	- Appendix G2-FORECAST, Sch 23
32							
33	**EARNED RETURN**	$ 218,996	$ 209,272	$ (5,179)	$ 204,093	$ (14,903)	- Appendix G2-FORECAST, Sch 58
34							
35							
36	**UTILITY RATE BASE**	$ 2,701,542	$ 2,801,311	$ (18)	$ 2,801,293	$ 99,751	- Appendix G2-FORECAST, Sch 29
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	8.11%	7.47%		7.29%	-0.82%	- Appendix G2-FORECAST, Sch 58

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

Schedule 5

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2013

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Projected Terajoules: Non-Bypass Sales & Transp	2013 Projected Terajoules: Bypass and Special Rates	2013 Projected Terajoules: Total	2013 Projected Terajoules: Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	69,753.0	69,816.4	69,644.2	-	69,644.2	(172.2)	
3	Schedule 2 - Small Commercial	24,319.0	23,331.9	24,087.6		24,087.6	755.7	
4	Schedule 3 - Large Commercial	16,744.0	16,514.8	17,354.8		17,354.8	840.0	
5								
6	Schedules 1, 2 and 3	110,816.0	109,663.1	111,086.6	-	111,086.6	1,423.5	
7								
8	Schedule 4 - Seasonal	169.0	185.2	169.1		169.1	(16.1)	
9	Schedule 5 - General Firm	2,315.0	2,407.7	2,315.3		2,315.3	(92.4)	
10								
11	Industrials							
12	Schedule 7 - Interruptible	87.0	14.2	86.7		86.7	72.5	
13								
14	Schedule 6 - N G V Fuel - Stations	62.0	56.4	61.4		61.4	5.0	
15	Schedule 16 - Liquefied Natural Gas (LNG)	172.0	-	226.5		226.5	226.5	
16	Total Sales	113,621.0	112,326.6	113,945.6	-	113,945.6	1,619.0	- Appendix G2-FORECAST, Sch 3
17								
18	**TRANSPORTATION SERVICE**							
19	Schedule 22 - Firm Service	18,884.0	17,089.5	13,208.0	6,874.9	20,082.9	2,993.4	
20	- Interruptible Service	18,760.0	12,302.6	15,940.9	-	15,940.9	3,638.3	
21	Byron Creek (aka Fording Coal Mountain)	393.0	227.4		179.1	179.1	(48.3)	
22	Burrard Thermal - Firm	482.0	1,372.0		482.5	482.5	(889.5)	
23	FEVI - Firm	21,244.0	37,080.0		33,553.2	33,553.2	(3,526.8)	
24	Schedule 23 - Large Commercial	7,803.0	7,485.3	8,168.1		8,168.1	682.8	
25	Schedule 25 - Firm Service	12,829.0	13,471.3	12,288.4	837.3	13,125.7	(345.6)	
26	Schedule 27 - Interruptible Service	6,372.0	5,804.8	6,324.5		6,324.5	519.7	
27								
28	Total Transportation Service	86,767.0	94,832.9	55,929.9	41,927.0	97,856.9	3,024.0	- Appendix G2-FORECAST, Sch 3
29								
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	200,388.0	207,160.0	169,875.5	41,927.0	211,802.5	4,643.0	- Appendix G2-FORECAST, Sch 3
31								

GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEAR ENDING DECEMBER 31, 2014

Line No.	Particulars	2013 PROJECTED	2014 Forecast Terajoules Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	69,644.2	69,511.7	-	69,511.7	(132.5)	
3	Schedule 2 - Small Commercial	24,087.6	24,246.8		24,246.8	159.2	
4	Schedule 3 - Large Commercial	17,354.8	17,253.0		17,253.0	(101.8)	
5							
6	Schedules 1, 2 and 3	111,086.6	111,011.5	-	111,011.5	(75.1)	
7							
8	Schedule 4 - Seasonal	169.1	169.1		169.1	-	
9	Schedule 5 - General Firm	2,315.3	2,315.3		2,315.3	-	
10							
11	Industrials						
12	Schedule 7 - Interruptible	86.7	86.7		86.7	-	
13							
14	Schedule 6 - N G V Fuel - Stations	61.4	61.4		61.4	-	
15	Schedule 16 - Liquefied Natural Gas (LNG)	226.5	1,341.3		1,341.3	1,114.8	
16	Total Sales	113,945.6	114,985.3	-	114,985.3	1,039.7	- Appendix G2-FORECAST, Sch 4
17							
18	**TRANSPORTATION SERVICE**						
19	Schedule 22 - Firm Service	20,082.9	13,188.4	6,553.2	19,741.6	(341.3)	
20	- Interruptible Service	15,940.9	15,822.0	-	15,822.0	(118.9)	
21	Byron Creek (aka Fording Coal Mountain)	179.1		176.6	176.6	(2.5)	
22	Burrard Thermal - Firm	482.5		482.5	482.5	-	
23	FEVI - Firm	33,553.2		33,720.0	33,720.0	166.8	
24	Schedule 23 - Large Commercial	8,168.1	8,721.3		8,721.3	553.2	
25	Schedule 25 - Firm Service	13,125.7	12,604.4	837.3	13,441.7	316.0	
26	Schedule 27 - Interruptible Service	6,324.5	6,476.3		6,476.3	151.8	
27							
28	Total Transportation Service	97,856.9	56,812.4	41,769.6	98,582.0	725.1	- Appendix G2-FORECAST, Sch 4
29							
30	**TOTAL SALES AND TRANSPORTATION SERVICES**	211,802.5	171,797.7	41,769.6	213,567.3	1,764.8	- Appendix G2-FORECAST, Sch 4
31							- Appendix G2-FORECAST, Sch 11

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 7

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	**SALES**							
2	Schedule 1 - Residential	$ 684,879	$ 750,275	$ 681,094	$ -	$ 681,094	$ (69,181)	
3	Schedule 2 - Small Commercial	207,547	222,969	206,458		206,458	(16,511)	
4	Schedule 3 - Large Commercial	123,547	139,001	125,680		125,680	(13,321)	
5	Schedules 1, 2 and 3	1,015,973	1,112,245	1,013,232	-	1,013,232	(99,013)	
6								
7	Schedule 4 - Seasonal	945	1,263	946	-	946	(317)	
8	Schedule 5 - General Firm	15,405	18,921	14,624		14,624	(4,297)	
9	Schedules 4 and 5	16,350	20,184	15,570	-	15,570	(4,614)	
10	Industrials							
11	Schedule 7 - Interruptible	489	133	459	-	459	326	
12								
13	Schedule 6 - N G V Fuel - Stations	480	500	467		467	(33)	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,337	-	1,711		1,711	1,711	
15	Total Sales	1,034,629	1,133,062	1,031,439	-	1,031,439	(101,623)	- Appendix G2-FORECAST, Sch 3
16								
17	**Transportation Service**							
18	Schedule 22 - Firm Service	7,173	8,837	10,521	823	11,344	2,507	
19	- Interruptible Service	17,350	11,101	15,087	-	15,087	3,986	
20	Byron Creek (aka Fording Coal Mountain)	78	55		32	32	(23)	
21	Burrard Thermal - Firm	9,965	9,996		9,965	9,965	(31)	
22	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch1:	-	-		-	-	-	
23	Schedule 23 - Large Commercial	22,810	21,153	25,171	-	25,171	4,018	
24	Schedule 25 - Firm Service	24,484	25,413	25,909	704	26,613	1,200	
25	Schedule 27 - Interruptible Service	8,323	7,390	8,739	-	8,739	1,349	
26	Total Transportation Service	90,183	83,945	85,427	11,524	96,951	13,006	- Appendix G2-FORECAST, Sch 3
27								
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,124,812	$ 1,217,007	$ 1,116,866	$ 11,524	$ 1,128,390	$ (88,617)	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 8

REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Gas Sales Revenue At Existing 2013 Rates: Non-Bypass Sales & Transp	Bypass and Special Rates	Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	$ 681,094	$ 676,106	$ -	$ 676,106	$ (4,988)	
3	Schedule 2 - Small Commercial	206,458	204,130		204,130	(2,328)	
4	Schedule 3 - Large Commercial	125,680	123,215		123,215	(2,465)	
5	Schedules 1, 2 and 3	1,013,232	1,003,451	-	1,003,451	(9,781)	
6							
7	Schedule 4 - Seasonal	946	946	-	946	-	
8	Schedule 5 - General Firm	14,624	14,624		14,624	-	
9	Schedules 4 and 5	15,570	15,570	-	15,570	-	
10	Industrials						
11	Schedule 7 - Interruptible	459	459	-	459	-	
12							
13	Schedule 6 - N G V Fuel - Stations	467	467		467	-	
14	Schedule 16 - Liquefied Natural Gas (LNG)	1,711	10,801		10,801	9,090	
15	Total Sales	1,031,439	1,030,748	-	1,030,748	(691)	- Appendix G2-FORECAST, Sch 4
16							
17	**Transportation Service**						
18	Schedule 22 - Firm Service	11,344	8,396	823	9,219	(2,125)	
19	- Interruptible Service	15,087	14,740	-	14,740	(347)	
20	Byron Creek (aka Fording Coal Mountain)	32		32	32	-	
21	Burrard Thermal - Firm	9,965		9,965	9,965	-	
22	FEVI - Firm (Revenue/Margin included in Other Revenue - Sch13)	-		-	-	-	
23	Schedule 23 - Large Commercial	25,171	26,766	-	26,766	1,595	
24	Schedule 25 - Firm Service	26,613	26,140	704	26,844	231	
25	Schedule 27 - Interruptible Service	8,739	8,922	-	8,922	183	
26	Total Transportation Service	96,951	84,964	11,524	96,488	(463)	- Appendix G2-FORECAST, Sch 4
27							
28	TOTAL SALES AND TRANSPORTATION SERVICES	$ 1,128,390	$ 1,115,712	$ 11,524	$ 1,127,236	$ (1,154)	- Appendix G2-FORECAST, Sch 4 - Appendix G2-FORECAST, Sch 11

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

COST OF GAS

Schedule 9

FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

($000s)

Line No.	Particulars	2013 Projected Gas Costs Non-Bypass Sales & Transp	2013 Bypass and Special Rates	2013 Total	2014 Forecast Gas Costs Non-Bypass Sales & Transp	2014 Bypass and Special Rates	2014 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**SALES**						
2	Schedule 1 - Residential	310,537	$ -	$ 310,537	$ 305,432	$ -	$ 305,432
3	Schedule 2 - Small Commercial	110,811		110,811	107,890		107,890
4	Schedule 3 - Large Commercial	72,872		72,872	70,770		70,770
5							
6	Schedules 1, 2 and 3	494,220	-	494,220	484,092	-	484,092
7							
8	Schedule 4 - Seasonal	629		629	629		629
9	Schedule 5 - General Firm	8,660		8,660	8,660		8,660
10							
11	Schedules 4 and 5	9,289	-	9,289	9,289	-	9,289
12							
13	Industrials						
14	Schedule 7 - Interruptible	323		323	323		323
15							
16	Schedule 6 - N G V Fuel - Stations	208		208	208		208
17	Schedule 16 - Liquefied Natural Gas (LNG)	778		778	5,275		5,275
18							
19	Total Sales	504,818	-	504,818	499,187	-	499,187
20							
21	**TRANSPORTATION SERVICE**						
22	Schedule 22 - Firm Service	268	58	326	44	31	75
23	- Interruptible Service	58	-	58	73	-	73
24	Byron Creek (aka Fording Coal Mountain)		7	7		-	-
25	Burrard Thermal - Firm		5	5		3	3
26	FEVI - Firm		324	324		210	210
27	Schedule 23 - Large Commercial	41	-	41	43	-	43
28	Schedule 25 - Firm Service	71	6	77	59	4	63
29	Schedule 27 - Interruptible Service	39	-	39	31	-	31
30							
31	Total Transportation Service	477	400	877	250	248	498
32							
33	TOTAL SALES AND TRANSPORTATION SERVICES	$ 505,295	$ 400	$ 505,695	$ 499,437	$ 248	$ 499,685
34							
35	Cross Reference			- Appendix G2-FORECAST, Sch 3			- Appendix G2-FORECAST, Sch 4

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Non-Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Terajoules	Revenue -- At Existing 2013 Rates -- Average $/GJ	Revenue ($000s)	Gross Margin -- At Existing 2013 Rates -- Average $/GJ	Margin ($000s)	Effective Increase / (Decrease) -1.12% $/GJ	of Margin Revenue ($000s)	Average Number of Customers	Revenue Average $/GJ	Revenue ($000s)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON-BYPASS**										
2	Sales										
3	Schedule 1 - Residential	69,511.7	$ 9.727	$ 676,106	$ 5.333	$ 370,675	$ (0.060)	$ (4,152)	765,842	$ 9.667	$ 671,954
4	Schedule 2 - Small Commercial	24,246.8	8.419	204,130	3.969	96,241	(0.044)	(1,078)	72,614	8.375	203,052
5	Schedule 3 - Large Commercial	17,253.0	7.142	123,215	3.040	52,444	(0.034)	(588)	4,577	7.108	122,627
6	Schedules 1, 2 and 3	111,011.5		1,003,451		519,360		(5,818)	843,033		997,633
7											
8	Schedule 4 - Seasonal	169.1	5.594	946	1.875	317	(0.024)	(4)	26	5.570	942
9	Schedule 5 - General Firm	2,315.3	6.316	14,624	2.576	5,965	(0.029)	(67)	216	6.287	14,557
10											
11	Industrials										
12	Schedule 7 - Interruptible	86.7	5.294	459	1.580	137	(0.023)	(2)	3	5.271	457
13											
14	Schedule 6 - N G V Fuel - Stations	61.4	7.606	467	4.218	259	(0.049)	(3)	14	7.557	464
15	Schedule 16 - Liquefied Natural Gas (LNG)	1,341.3	8.053	10,801	4.120	5,526	(0.046)	(62)	8	8.007	10,739
16	Total Sales	114,985.3		1,030,748		531,564		(5,956)	843,300		1,024,792
17											
18	TRANSPORTATION SERVICE										
19	Schedule 22 - Firm Service	13,188.4	0.637	8,396	0.633	8,352	(0.007)	(94)	14	0.630	8,302
20	- Interruptible Service	15,822.0	0.932	14,740	0.927	14,667	(0.010)	(165)	25	0.922	14,575
21	Schedule 23 - Large Commercial	8,721.3	3.069	26,766	3.064	26,723	(0.034)	(300)	1,560	3.035	26,466
22	Schedule 25 - Firm Service	12,604.4	2.074	26,140	2.069	26,081	(0.023)	(292)	487	2.051	25,848
23	Schedule 27 - Interruptible Service	6,476.3	1.378	8,922	1.373	8,891	(0.015)	(99)	95	1.363	8,823
24											
25	Total Transportation Service	56,812.4		84,964		84,714		(950)	2,181		84,014
26											
27	Total Non-Bypass Sales & Transportation Service	171,797.7		$ 1,115,712		$ 616,278		$ (6,906)	845,481		$ 1,108,806
28											
29	Cross Reference	- Appendix G2-FORECAST, Sch 6		- Appendix G2-FORECAST, Sch 8				- Appendix G2-FORECAST, Sch 4			

REVENUE UNDER EXISTING 2013 RATES AND REVISED 2014 RATES (Bypass)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

			Revenue -- At Existing 2013 Rates --		Gross Margin -- At Existing 2013 Rates --		Increase / (Decrease) -1.12% of Margin			Revenue	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Margin ($000s)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**BYPASS AND SPECIAL RATES**										
2	Bypass and Special Rates Transportation Service										
3	Schedule 22 - Firm Service	6,553.2	$ 0.126	$ 823	$ 0.121	$ 791	$ -	$ -	5	$ 0.126	$ 823
4	- Interruptible Service	-	-	-	-	-	-	-	1	-	-
5	Byron Creek (aka Fording Coal Mountain)	176.6	0.181	32	0.181	32	-	-	1	0.181	32
6	Burrard Thermal - Firm	482.5	20.653	9,965	20.647	9,962	-	-	1	20.653	9,965
7	FEVI - Firm (Revenue/Margin included in Other Revenue - Sc	33,720.0	-	-	-	-	-	-	1	-	-
8	Schedule 23 - Large Commercial	-	-	-	-	-	-	-	-	-	-
9	Schedule 25 - Firm Service	837.3	0.841	704	0.836	700	-	-	6	0.841	704
10	Schedule 27 - Interruptible Service	-	-	-	-	-	-	-	-	-	-
11	Total Bypass and Spec. Rates T-Svc	41,769.6		11,524		11,485		-	15		11,524
12											
13	TOTAL NON-BYPASS AND BYPASS SALES AND										
14	TRANSPORTATION SERVICE	213,567.3		$ 1,127,236		$ 627,763		$ (6,906)	845,496		$ 1,120,330
15											
16	Cross Reference	- Appendix G2-FORECAST, Sch 6		- Appendix G2-FORECAST, Sch 8				- Appendix G2-FORECAST, Sch 2			

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 12

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Other Utility Revenue**					
2						
3	Late Payment Charge	$ 2,402	$ 2,333	$ 2,134	$ (199)	- Appendix G2-FORECAST, Sch 54
4						
5	Connection Charge	2,390	2,685	2,622	(63)	- Appendix G2-FORECAST, Sch 54
6						
7	NSF Returned Cheque Charges	110	79	79	-	- Appendix G2-FORECAST, Sch 54
8						
9	Other Recoveries	237	126	284	158	- Appendix G2-FORECAST, Sch 54
10						
11	Total Other Utility Revenue	5,139	5,223	5,119	(104)	
12						
13	**Miscellaneous Revenue**					
14						
15	FEVI Wheeling Charge	3,353	3,464	3,464	-	
16						
17	SCP Third Party Revenue	15,272	14,827	14,773	(54)	
18						
19	FEVI SAP Lease Income	17	-	-	-	- Appendix G2-FORECAST, Sch 54
20						
21	NGT Overhead and Marketing Recovery	-	-	-	-	- Appendix G2-FORECAST, Sch 54
22						
23	Surrey & Burnaby Operations CNG Pump Charges	-	-	(55)	(55)	- Appendix G2-FORECAST, Sch 54
24						
25	Biomethane Other Revenue	-	(29)	(97)	(68)	- Appendix G2-FORECAST, Sch 54
26						
27	CNG & LNG Service Revenues	720	1,304	-	(1,304)	- Appendix G2-FORECAST, Sch 54
28						
29						
30	Total Miscellaneous	19,362	19,566	18,085	(1,481)	
31						
32	**Total Other Operating Revenue**	$ 24,501	$ 24,789	$ 23,204	$ (1,585)	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 13

OTHER OPERATING REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Other Utility Revenue**				
2					
3	Late Payment Charge	$ 2,134	$ 2,114	$ (20)	- Appendix G2-FORECAST, Sch 54
4					
5	Connection Charge	2,622	2,636	14	- Appendix G2-FORECAST, Sch 54
6					
7	NSF Returned Cheque Charges	79	79	-	- Appendix G2-FORECAST, Sch 54
8					
9	Other Recoveries	284	284	-	- Appendix G2-FORECAST, Sch 54
10					
11	Total Other Utility Revenue	5,119	5,113	(6)	
12					
13	**Miscellaneous Revenue**				
14					
15	FEVI Wheeling Charge	3,464	3,365	(99)	- Appendix G2-FORECAST, Sch 2
16					
17	SCP Third Party Revenue	14,773	14,773	-	- Appendix G2-FORECAST, Sch 2
18					
19	FEVI SAP Lease Income	-	-	-	- Appendix G2-FORECAST, Sch 54
20					
21	NGT Overhead and Marketing Recovery	-	490	490	- Appendix G2-FORECAST, Sch 54
22					
23	Surrey & Burnaby Operations CNG Pump Charges	(55)	(55)	-	- Appendix G2-FORECAST, Sch 54
24					
25	Biomethane Other Revenue	(97)	(70)	27	- Appendix G2-FORECAST, Sch 54
26					
27	CNG & LNG Service Revenues	-	-	-	- Appendix G2-FORECAST, Sch 54
28					
29					
30	Total Miscellaneous	18,085	18,503	418	
31					
32	**Total Other Operating Revenue**	$ 23,204	$ 23,616	$ 412	- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 14

OPERATION & MAINTENANCE EXPENSES - RESOURCE VIEW
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	M&E Costs	$ 50,708	$ 59,097	$ 55,817	$ 61,209	
2	COPE Costs	32,450	37,183	31,780	35,331	
3	COPE Customer Services Costs	11,825	11,144	11,644	13,340	
4	IBEW Costs	27,180	27,640	26,472	29,724	
5						
6	**Labour Costs**	**122,164**	**135,064**	**125,713**	**139,604**	
7						
8	Vehicle Costs	3,807	3,685	3,855	4,149	
9	Employee Expenses	5,898	5,716	5,671	5,828	
10	Materials and Supplies	7,903	7,019	6,841	7,125	
11	Computer Costs	14,570	14,769	15,274	16,028	
12	Fees and Administration Costs	38,611	37,905	38,449	41,214	
13	Contractor Costs	31,955	38,335	40,896	31,081	
14	Facilities	15,486	14,284	13,976	14,545	
15	Recoveries & Revenue	(20,689)	(20,774)	(19,055)	(19,642)	
16						
17	**Non-Labour Costs**	**97,540**	**100,939**	**105,906**	**100,329**	
18						
19						
20	**Total Gross O&M Expenses**	**219,704**	**236,003**	**231,618**	**239,933**	
21						
22	Less: Capitalized Overhead	(31,779)	(33,040)	(33,040)	(33,591)	
23						
24	**Total O&M Expenses**	**$ 187,925**	**$ 202,963**	**$ 198,578**	**$ 206,343**	
25						
26	Cross Reference			- Appendix G2-FORECAST, Sch 3		
27					- Appendix G2-FORECAST, Sch 4	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW Schedule 15

FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Supervision	110-11	$ 10,578	$ 11,026	$ 11,194	$ 12,440	
2	Distribution Supervision Total	110-10	10,578	11,026	11,194	12,440	
3							
4	Operation Centre - Distribution	110-21	10,112	11,074	9,901	11,204	
5	Preventative Maintenance - Distribution	110-22	2,644	2,990	2,844	3,323	
6	Operations - Distribution	110-23	5,538	5,904	6,409	6,331	
7	Emergency Management - Distribution	110-24	5,405	5,077	5,337	6,480	
8	Field Training - Distribution	110-25	1,746	4,088	3,153	3,547	
9	Meter Exchange - Distribution	110-26	2,397	2,231	2,373	3,161	
10	Distribution Operations Total	110-20	27,842	31,363	30,018	34,046	
11							
12	Corrective - Distribution	110-31	5,564	4,643	5,559	5,979	
13	Distribution Maintenance Total	110-30	5,564	4,643	5,559	5,979	
14							
15	Account Services - Distribution	110-41	1,111	1,004	1,081	1,249	
16	Bad Debt Management - Distribution	110-42	585	599	443	569	
17	Distribution Meter to Cash Total	110-40	1,697	1,603	1,524	1,818	
18							
19	**Distribution Total**	**110**	**45,680**	**48,635**	**48,295**	**54,282**	
20							
21	Transmission Supervision	120-11	535	482	606	694	
22	Transmission Supervision Total	120-10	535	482	606	694	
23							
24	Pipeline / Right of Way Operations	120-21	7,287	6,096	6,163	6,755	
25	Compression Operations	120-22	1,827	2,112	1,813	2,023	
26	Measurement Control Operations	120-23	103	-	-	17	
27	Transmission Operations Total	120-20	9,217	8,208	7,976	8,795	
28							
29	Pipeline / Right of Way - Maintenance	120-31	1,830	2,707	3,206	3,263	
30	Compression - Maintenance	120-32	554	1,147	1,216	1,230	
31	Measurement Control Operations	120-33	117	119	201	204	
32	Transmission Maintenance Total	120-30	2,501	3,973	4,623	4,697	
33							
34	**Transmission Total**	**120**	**12,253**	**12,663**	**13,205**	**14,186**	
35							
36	LNG Operations	130-11	1,601	1,617	1,717	2,218	
37	LNG Operations Total	130-10	1,601	1,617	1,717	2,218	
38							
39	LNG Plant Maintenance	130-21	272	274	292	377	
40	LNG Plant Maintenance Total	130-20	272	274	292	377	
41							
42	**LNG Plant Total**	**130**	**1,873**	**1,891**	**2,009**	**2,595**	
43							
44	**Operations Total**	**100**	**59,806**	**63,189**	**63,509**	**71,062**	
45							
46	Customer Service Supervision	210-11	482	566	566	636	
47	Customer Assistance	210-12	11,513	11,493	11,480	14,290	
48	Customer Billing	210-13	18,586	14,494	14,494	12,988	
49	Meter Reading	210-14	12,178	19,696	19,696	11,270	
50	Credit & Collections	210-15	3,028	3,851	3,787	3,861	
51	Customer Operations	210-16	2,385	2,353	2,088	2,309	
52	Customer Service Total	210-10	48,172	52,452	52,110	45,352	
53							
54	**Customer Service Total**	**210**	**48,172**	**52,452**	**52,110**	**45,352**	
55							
56	**Customer Service Total**	**200**	**48,172**	**52,452**	**52,110**	**45,352**	

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued)
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Energy Solutions & External Relations Supervision	310-11	$ 614	$ 796	$ 671	$ 700	
2	Energy Solutions	310-12	5,134	4,991	5,117	6,009	
3	Energy Efficiency	310-13	117	120	301	308	
4	Corporate Communications and External Relations	310-14	7,212	6,155	6,988	8,609	
5	Forecasting, Market & Business Development	310-15	4,998	6,119	6,138	7,649	
6	Energy Solutions & External Relations Total	310-10	18,075	18,181	19,215	23,275	
7							
8	**Energy Solutions & External Relations Total**	**310**	**18,075**	**18,181**	**19,215**	**23,275**	
9							
10	**Energy Solutions & External Relations Total**	**300**	**18,075**	**18,181**	**19,215**	**23,275**	
11							
12	Energy Supply & Resource Development	410-11	1,937	2,136	2,550	2,938	
13	Gas Control	410-12	1,551	1,602	1,451	1,800	
14	Energy Supply & Resource Development Total	410-10	3,488	3,738	4,000	4,738	
15							
16	**Energy Supply & Resource Development Total**	**410**	**3,488**	**3,738**	**4,000**	**4,738**	
17							
18	Information Technology Supervision	420-11	4,172	4,577	4,001	4,276	
19	Application Management	420-12	11,251	12,083	11,980	11,101	
20	Infrastructure Management	420-13	8,018	8,719	8,236	9,015	
21	Information Technology Total	420-10	23,442	25,379	24,217	24,392	
22							
23	**Information Technology Total**	**420**	**23,442**	**25,379**	**24,217**	**24,392**	
24							
25	System Planning	430-11	5,672	8,394	7,675	8,859	
26	Engineering	430-12	6,803	7,027	6,760	7,657	
27	Project Management	430-13	1,125	1,535	1,021	1,220	
28	Engineering Services & Project Management Total	430-10	13,599	16,956	15,456	17,736	
29							
30	**Engineering Services & Project Management Total**	**430**	**13,599**	**16,956**	**15,456**	**17,736**	
31							
32	Supply Chain	440-11	4,420	4,884	4,450	5,234	
33	Measurement	440-12	5,548	6,688	6,124	6,983	
34	Property Services	440-13	1,070	1,418	1,293	1,481	
35	Operations Support Total	440-10	11,038	12,990	11,867	13,698	
36							
37	**Operations Support Total**	**440**	**11,038**	**12,990**	**11,867**	**13,698**	
38							
39	Facilities Management	450-11	9,563	9,259	9,249	9,959	
40	Facilities Total	450-10	9,563	9,259	9,249	9,959	
41							
42	**Facilities Total**	**450**	**9,563**	**9,259**	**9,249**	**9,959**	
43							
44	Environment Health & Safety	460-11	2,481	2,999	2,681	2,934	
45	Environment Health & Safety Total	460-10	2,481	2,999	2,681	2,934	
46							
47	**Environment Health & Safety Total**	**460**	**2,481**	**2,999**	**2,681**	**2,934**	
48							
49							
50	**Business Services Total**	**400**	**63,611**	**71,321**	**67,470**	**73,457**	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (Continued) Schedule 17

FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014

($000)

Line No.	Particulars	BCUC Reference	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Financial & Regulatory Services	510-11	12,149	$ 14,184	13,279	15,401	
2	Financial & Regulatory Services Total	510-10	12,149	14,184	13,279	15,401	
3							
4	**Financial & Regulatory Services Total**	**510**	**12,149**	**14,184**	**13,279**	**15,401**	
5							
6	Human Resources	520-11	8,610	8,511	8,458	9,399	
7	Human Resources Total	520-10	8,610	8,511	8,458	9,399	
8							
9	**Human Resources Total**	**520**	**8,610**	**8,511**	**8,458**	**9,399**	
10							
11	Legal	530-11	1,917	2,282	2,282	2,325	
12	Internal Audit	530-12	695	755	755	769	
13	Risk Management/Insurance	530-13	4,754	4,898	4,898	5,277	
14	Governance	530-10	7,366	7,935	7,935	8,371	
15							
16	**Governance Total**	**530**	**7,366**	**7,935**	**7,935**	**8,371**	
17							
18	Administration & General	540-11	226	(46)	269	575	
19	Shared Services Agreement	540-12	(5,984)	(5,581)	(6,483)	(6,960)	
20	Retiree Benefits	540-16	7,673	5,857	5,857	-	
21	Corporate Total	540-10	1,915	230	(357)	(6,385)	
22							
23	**Corporate Total**	**540**	**1,915**	**230**	**(357)**	**(6,385)**	
24							
25	**Corporate Services Total**	**500**	**30,041**	**30,860**	**29,314**	**26,786**	
26							
27	**Total Gross O&M Expenses**		**219,704**	**236,003**	**231,618**	**239,934**	
28							
29	Less: Capitalized Overhead		(31,779)	(33,040)	(33,040)	(33,591)	
30							
31	**Total O&M Expenses**		**$ 187,925**	**$ 202,963**	**$ 198,578**	**$ 206,343**	
32							
33	Cross Reference				- Appendix G2-FORECAST, Sch 3		
34						- Appendix G2-FORECAST, Sch 4	

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2 FORECAST Schedule 18

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Total Expenses	2013 2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	Property Taxes						
2							
3	1% in Lieu of General Municipal Tax	$ 13,283	$ 13,728	$ 12,542	$ 12,542	$ (1,186)	
4							
5	General, School and Other	34,132	37,511	35,547	35,547	(1,964)	
6							
7		47,415	51,239	48,089	48,089	(3,150)	
8							
9	Add / Less: Deferred Property Taxes	2,241	-	3,150	3,150	3,150	
10							
11	Total	$ 49,656	$ 51,239	$ 51,239	$ 51,239	$ -	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 19

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

			2014			
Line No.	Particulars	2013 PROJECTED	Total Expenses	2013 Rates, Total Expenses	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Property Taxes					
2						
3	1% in Lieu of General Municipal Tax	$ 12,542	$ 12,032	$ 12,032	$ (510)	
4						
5	General, School and Other	35,547	36,765	36,765	1,218	
6						
7		48,089	48,797	48,797	708	
8						
9	Add / Less: Deferred Property Taxes	3,150	-	-	(3,150)	
10						
11	Total	$ 51,239	$ 48,797	$ 48,797	$ (2,442)	- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 20

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Depreciation & Removal Provision**					
2						
3	Depreciation Expense	$ 118,639	$ 123,842	$ 123,842	$ -	- Appendix G2-FORECAST, Sch 39
4						
5	Less: Amortization of Contributions in Aid of Construction	(6,558)	(6,499)	(6,499)	-	- Appendix G2-FORECAST, Sch 43
6		112,081	117,343	117,343	-	- Appendix G2-FORECAST, Sch 24
7						
8	**Amortization Expense**					
9						
10	Amortization of Deferred Charges	$ 11,847	$ 25,569	$ 25,569	$ -	- Appendix G2-FORECAST, Sch 46
11						
12	TOTAL	123,928	142,912	142,912	$ -	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 21

DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars (1)	2013 PROJECTED (2)	2014 (3)	Change (4)	Cross Reference (5)
1	**Depreciation & Removal Provision**				
2					
3	Depreciation Expense	$ 123,842	$ 124,759	$ 917	- Appendix G2-FORECAST, Sch 42
4					
5	Less: Amortization of Contributions in Aid of Construction	(6,499)	(6,320)	179	- Appendix G2-FORECAST, Sch 44
6		117,343	118,439	1,096	- Appendix G2-FORECAST, Sch 25
7					
8	**Amortization Expense**				
9					
10	Amortization of Deferred Charges	$ 25,569	$ 30,216	$ 4,647	- Appendix G2-FORECAST, Sch 48
11					
12	TOTAL	$ 142,912	148,655	$ 5,743	- Appendix G2-FORECAST, Sch 4

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 Existing Rates	2013 Revised Revenue	2013 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7) (Column (6) - Column (3))	(8)
1	CALCULATION OF INCOME TAXES							
2	EARNED RETURN	$ 221,574	$ 216,404	$ 218,996	$ -	$ 218,996	$ 2,592	- Appendix G2-FORECAST, Sch 3
3	Deduct - Interest on Debt	(108,979)	(111,220)	(109,825)	-	(109,825)	1,395	- Appendix G2-FORECAST, Sch 57
4	Net Additions (Deductions)	(31,957)	(21,038)	(26,648)	-	(26,648)	(5,610)	- Appendix G2-FORECAST, Sch 24
5	Accounting Income After Tax	80,638	84,146	82,523	$ -	82,523	(1,623)	
6								
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	75.00%	0.00%	
9								
10	Taxable Income	$ 107,518	$ 112,195	$ 110,031	$ -	$ 110,031	$ (2,164)	
11								
12								
13	Income Tax - Current	$ 26,880	$ 28,049	$ 27,508	$ -	$ 27,508	$ (541)	
14	Previous Year Adjustment	-	-		-		-	
15								
16	**Total Income Tax**	$ 26,880	$ 28,049	$ 27,508	$ -	$ 27,508	$ (541)	- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 23

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 Existing Rates	2014 Revised Revenue	2014 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 218,996	$ 209,272	$ (5,179)	$ 204,093	$ (14,903)	- Appendix G2-FORECAST, Sch 4
3	Deduct - Interest on Debt	(109,825)	(109,724)	-	(109,724)	101	- Appendix G2-FORECAST, Sch 58
4	Net Additions (Deductions)	(26,648)	14,751	-	14,751	41,399	- Appendix G2-FORECAST, Sch 25
5	Accounting Income After Tax	82,523	114,299	$ (5,179)	109,120	26,597	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	110,031	$ 152,399	$ (6,906)	$ 145,493	$ 35,462	
11							
12							
13	Income Tax - Current	$ 27,508	$ 38,100	$ (1,727)	$ 36,373	$ 8,865	
14	Previous Year Adjustment	-		-		-	
15							
16	**Total Income Tax**	$ 27,508	$ 38,100	$ (1,727)	$ 36,373	$ 8,865	- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 24

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5) (Column (4) - Column (3))	(6)
1	**Addbacks:**					
2	Non-tax Deductible Expenses	$ 677	$ 700	700	$ -	
3	Depreciation	112,081	117,343	117,343	-	- Appendix G2-FORECAST, Sch 20
4	Amortization of Debt Issue Expenses	537	622	561	(61)	
5	Vehicle: Interest & Capitialized Depreciation	1,898	2,187	1,692	(495)	
6	Pension Expense	14,097	12,530	12,530	-	
7	OPEB Expense	4,765	4,902	4,902	-	
8	Olympic Cauldron (50% NBV)	1,445	-	-	-	
9	Bad Debt Provision	726	-	-	-	
10						
11	**Deductions:**					
12	Amortization of Deferred Charges	11,847	25,569	25,569	-	- Appendix G2-FORECAST, Sch 20
13	Capital Cost Allowance	(129,279)	(136,232)	(136,232)	-	- Appendix G2-FORECAST, Sch 26
14	Cumulative Eligible Capital Allowance	(907)	(857)	(865)	(8)	
15	Debt Issue Costs	(834)	(411)	(385)	26	
16	Vehicle Lease Payment	(3,432)	(4,613)	(4,183)	430	
17	Pension Contributions	(13,920)	(12,006)	(12,666)	(660)	
18	OPEB Contributions	(1,667)	(2,367)	(2,407)	(40)	
19	Overheads Capitalized Expensed for Tax Purposes	(13,620)	(14,160)	(14,160)	-	
20	Removal Costs	(14,766)	(12,932)	(14,201)	(1,269)	
21	Discounts on Debt Issue and Other	-	-	-	-	
22	Major Inspection Costs	(1,606)	(1,342)	(4,943)	(3,601)	
23	Biomethane Other Revenue	-	29	97	68	
24						
25	TOTAL	(31,957)	(21,038)	$ (26,648)	$ (5,610)	- Appendix G2-FORECAST, Sch 22

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 25

ADJUSTMENTS TO TAXABLE INCOME
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Addbacks:**				
2	Non-tax Deductible Expenses	$ 700	800	$ 100	
3	Depreciation	117,343	118,439	1,096	- Appendix G2-FORECAST, Sch 21
4	Amortization of Debt Issue Expenses	561	734	173	
5	Vehicle: Interest & Capitialized Depreciation	1,692	1,372	(320)	
6	Pension Expense	12,530	20,004	7,474	
7	OPEB Expense	4,902	8,662	3,760	
8	Olympic Cauldron (50% NBV)	-	-	-	
9	Bad Debt Provision	-	-	-	
10					
11	Deductions:				
12	Amortization of Deferred Charges	25,569	30,216	4,647	- Appendix G2-FORECAST, Sch 21
13	Capital Cost Allowance	(136,232)	(112,968)	23,264	- Appendix G2-FORECAST, Sch 27
14	Cumulative Eligible Capital Allowance	(865)	(804)	61	
15	Debt Issue Costs	(385)	(202)	183	
16	Vehicle Lease Payment	(4,183)	(3,006)	1,177	
17	Pension Contributions	(12,666)	(16,114)	(3,448)	
18	OPEB Contributions	(2,407)	(2,631)	(224)	
19	Overheads Capitalized Expensed for Tax Purposes	(14,160)	(14,396)	(236)	
20	Removal Costs	(14,201)	(13,327)	874	
21	Discounts on Debt Issue and Other	-	-	-	
22	Major Inspection Costs	(4,943)	(2,098)	2,845	
23	Biomethane Other Revenue	97	70	(27)	
24					
25	TOTAL	$ (26,648)	$ 14,751	$ 41,399	- Appendix G2-FORECAST, Sch 23

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Class	CCA Rate	12/31/2012 UCC Balance	Adjustments	2013 Net Additions	2013 CCA	12/31/2013 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,044,769	$ -	$ -	$ (41,791)	$ 1,002,978
2	1(b)	6%	27,756	-	5,949	(1,844)	31,861
3	2	6%	136,353	-	-	(8,181)	128,172
4	3	5%	2,423	-	-	(121)	2,302
5	6	10%	150	-	-	(15)	135
6	7	15%	5,442	-	2,067	(971)	6,538
7	8	20%	23,402	(1,412)	5,966	(4,995)	22,961
8	10	30%	1,680	-	-	(504)	1,176
9	12	100%	26,830	-	12,960	(33,310)	6,480
10	13	manual	3,517	-	163	(687)	2,993
11	17	8%	174	-	-	(14)	160
12	38	30%	511	-	-	(153)	358
13	45	45%	202	-	-	(91)	111
14	47	8%	5,496	-	1,835	(513)	6,818
15	49	8%	77,300	-	17,021	(6,865)	87,456
16	50	55%	7,461	-	8,640	(6,479)	9,622
17	51	6%	336,347	-	94,601	(23,019)	407,929
18	43.2	50%	-	-	-	-	-
19		Total	$ 1,699,813	$ (1,412)	$ 149,202	$ (129,553)	$ 1,718,050
20							
21	Add: Depreciation variance adjustment					(6,679)	
22	Approved CCA					$ (136,232)	
23							
24	Cross Reference					- Appendix G2-FORECAST, Sch 24	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Class	CCA Rate	12/31/2013 UCC Balance	Adjustments	2014 Net Additions	2014 CCA	12/31/2014 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,002,978	$ -	$ 125	$ (40,122)	$ 962,981
2	1(b)	6%	31,861	-	3,886	(2,028)	33,719
3	2	6%	128,172	-	-	(7,690)	120,482
4	3	5%	2,302	-	-	(115)	2,187
5	6	10%	135	-	-	(14)	121
6	7	15%	6,538	-	1,817	(1,117)	7,238
7	8	20%	22,961	-	4,515	(5,044)	22,432
8	10	30%	1,176	-	2,600	(743)	3,033
9	12	100%	6,480	-	12,067	(12,513)	6,034
10	13	manual	2,993	-	274	(313)	2,954
11	17	8%	160	-	-	(13)	147
12	38	30%	358	-	-	(107)	251
13	45	45%	111	-	-	(50)	61
14	47	8%	6,818	-	4,072	(708)	10,182
15	49	8%	87,456	-	4,465	(7,175)	84,746
16	50	55%	9,622	-	8,044	(7,504)	10,162
17	51	6%	407,929	-	107,884	(27,712)	488,101
18	43.2	50%	-	-	-	-	-
19		Total	$ 1,718,050	$ -	$ 149,749	$ (112,968)	$ 1,754,831
20							
21							
22							
23							
24	Cross Reference				- Appendix G2-FORECAST, Sch 25		

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 28

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
							(Column (6) - Column (3))	
1	Gas Plant in Service, Beginning	$ 3,545,030	$ 3,774,425	$ 3,726,853	$ -	$ 3,726,853	$ (47,572)	- Appendix G2-FORECAST, Sch 33
2	Opening Balance Adjustment	(3,890)	-	(3,818)	-	(3,818)	(3,818)	
3	Gas Plant in Service, Ending	3,726,853	3,905,299	3,870,158	-	3,870,158	(35,141)	- Appendix G2-FORECAST, Sch 33
4								
5	Accumulated Depreciation Beginning - Plant	$ (922,011)	$ (1,012,343)	$ (1,011,179)	$ -	$ (1,011,179)	$ 1,164	- Appendix G2-FORECAST, Sch 39
6	Opening Balance Adjustment	4,463	-	518	-	518	518	
7	Accumulated Depreciation Ending - Plant	(1,011,179)	(1,104,066)	(1,105,308)	-	(1,105,308)	(1,242)	- Appendix G2-FORECAST, Sch 39
8								
9	CIAC, Beginning	$ (180,038)	$ (191,772)	$ (185,545)	$ -	$ (185,545)	$ 6,227	- Appendix G2-FORECAST, Sch 43
10	Opening Balance Adjustment	-	-	-	-	-	-	
11	CIAC, Ending	(185,545)	(198,468)	(194,421)	-	(194,421)	4,047	- Appendix G2-FORECAST, Sch 43
12								
13	Accumulated Amortization Beginning - CIAC	$ 49,620	$ 51,072	$ 51,143	$ -	$ 51,143	$ 71	- Appendix G2-FORECAST, Sch 43
14	Opening Balance Adjustment	(5)	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	51,143	57,367	57,362	-	57,362	(5)	- Appendix G2-FORECAST, Sch 43
16								
17	Net Plant in Service, Mid-Year	$ 2,537,220	$ 2,640,757	$ 2,602,882	$ -	$ 2,602,882	$ (37,875)	
18								
19	Adjustment to 13-Month Average	30,786	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	20,803	26,120	-	26,120	5,317	
21	Unamortized Deferred Charges	497	8,249	(7,840)	-	(7,840)	(16,089)	- Appendix G2-FORECAST, Sch 46
22	Cash Working Capital	(1,899)	(2,293)	(1,591)	-	(1,591)	702	- Appendix G2-FORECAST, Sch 51
23	Other Working Capital	101,416	101,622	83,121	-	83,121	(18,501)	- Appendix G2-FORECAST, Sch 51
24	Deferred Income Taxes Regulatory Asset	281,929	282,359	284,958	-	284,958	2,599	- Appendix G2-FORECAST, Sch 56
25	Deferred Income Taxes Regulatory Liability	(281,929)	(282,359)	(284,958)	-	(284,958)	(2,599)	- Appendix G2-FORECAST, Sch 56
26	LILO Benefit	(1,316)	(1,150)	(1,150)	-	(1,150)	-	
27	**Utility Rate Base**	$ 2,692,824	$ 2,767,988	$ 2,701,542	$ -	$ 2,701,542	$ (66,446)	- Appendix G2-FORECAST, Sch 57
28								- Appendix G2-FORECAST, Sch 3

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 29

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,726,853	$ 3,870,158	$ -	$ 3,870,158	$ 143,305	- Appendix G2-FORECAST, Sch 36
2	Opening Balance Adjustment	(3,818)	-	-	-	3,818	
3	Gas Plant in Service, Ending	3,870,158	4,013,029	-	4,013,029	142,871	- Appendix G2-FORECAST, Sch 36
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,011,179)	$ (1,105,308)	$ -	$ (1,105,308)	$ (94,129)	- Appendix G2-FORECAST, Sch 42
6	Opening Balance Adjustment	518	-	-	-	(518)	
7	Accumulated Depreciation Ending - Plant	(1,105,308)	(1,206,131)	-	(1,206,131)	(100,823)	- Appendix G2-FORECAST, Sch 42
8							
9	CIAC, Beginning	$ (185,545)	$ (194,421)	$ -	$ (194,421)	$ (8,876)	- Appendix G2-FORECAST, Sch 44
10	Opening Balance Adjustment	-	-	-	-	-	
11	CIAC, Ending	(194,421)	(196,475)	-	(196,475)	(2,054)	- Appendix G2-FORECAST, Sch 44
12							
13	Accumulated Amortization Beginning - CIAC	$ 51,143	$ 57,362	$ -	$ 57,362	$ 6,219	- Appendix G2-FORECAST, Sch 44
14	Opening Balance Adjustment	-	-	-	-	-	
15	Accumulated Amortization Ending - CIAC	57,362	59,914	-	59,914	2,552	- Appendix G2-FORECAST, Sch 44
16							
17	Net Plant in Service, Mid-Year	$ 2,602,882	$ 2,649,064	$ -	$ 2,649,064	$ 46,183	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	(7,840)	48,293	-	48,293	56,133	- Appendix G2-FORECAST, Sch 48
22	Cash Working Capital	(1,591)	(222)	(18)	(240)	1,351	- Appendix G2-FORECAST, Sch 52
23	Other Working Capital	83,121	79,039	-	79,039	(4,082)	- Appendix G2-FORECAST, Sch 52
24	Deferred Income Taxes Regulatory Asset	284,958	288,491	-	288,491	3,533	- Appendix G2-FORECAST, Sch 56
25	Deferred Income Taxes Regulatory Liability	(284,958)	(288,491)	-	(288,491)	(3,533)	- Appendix G2-FORECAST, Sch 56
26	LILO Benefit	(1,150)	(983)	-	(983)	167	
27	**Utility Rate Base**	$ 2,701,542	$ 2,801,311	$ (18)	$ 2,801,293	$ 99,751	- Appendix G2-FORECAST, Sch 58
28							- Appendix G2-FORECAST, Sch 4

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 30

CAPITAL EXPENDITURES AND PLANT ADDITIONS
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000)

Line No.	Particulars (1)	2013 Projected (2)	2014 Forecast (3)	Cross Reference (4)
1	**CAPITAL EXPENDITURES**			
2				
3	Regular Capital Expenditures			
4				
5	Regular Capital Expenditures	$ 129,644	$ 138,585	
6	Gateway Project	3,012	-	
7				
8	Total Regular Capital Expenditures	$ 132,656	$ 138,585	
9				
10	TOTAL CAPITAL EXPENDITURES	$ 132,656	$ 138,585	
11				
12				
13	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**			
14				
15	Regular Capital			
16	Regular Capital Expenditures	$ 132,656	$ 138,585	
17	Add - Opening WIP	43,661	31,463	
18	Less - Adjustments	-	-	
19	Less - Closing WIP	(31,463)	(31,463)	
20	Capital Spares Inventory	-	-	
21	Capital Vehicle Lease	2,400	-	
22	Add - AFUDC	1,954	1,732	
23	Add - Overhead Capitalized	33,040	33,591	
24				
25	TOTAL REGULAR CAPITAL ADDITIONS TO GAS PLANT IN SERVICE	$ 182,249	$ 173,908	
26				
27	Special Projects - CPCN's			
28	CPCN Expenditures	$ -	$ -	
29	Add - Opening WIP	(158)	-	
30	Less - Closing WIP	-	-	
31	Add: Projects transferred from Deferral Accounts	158	-	
32	Less: Projects settling to Deferral Accounts	-	-	
33	Less: Adjustments	-	-	
34	Less: Removal Costs	-	-	
34	Add - AFUDC	-	-	
35				
36	TOTAL CPCN ADDITIONS	$ -	$ -	
37				
38	TOTAL PLANT ADDITIONS	$ 182,249	$ 173,908	
39				
40	Cross Reference	- Appendix G2-FORECAST, Sch 33		
41			- Appendix G2-FORECAST, Sch 36	

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 31

GAS PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**INTANGIBLE PLANT**									
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,529	-	393	-	-	-	-	44,922	44,726
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	-	-	-	-	-	-	1,209	1,209
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1	1
16	402-01 Application Software - 12.5%	85,471	-	6,480	168	-	(6,015)	-	86,104	85,788
17	402-02 Application Software - 20%	18,723	-	6,480	97	-	(2,997)	-	22,303	20,513
18	TOTAL INTANGIBLE	152,412	-	13,353	265	-	(9,012)	-	157,018	154,715
19										
20	**MANUFACTURED GAS / LOCAL STORAGE**									
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	-	-	-	-	-	-	965	965
24	433-00 Manufact'd Gas - Equipment	448	-	210	-	71	-	-	729	589
25	434-00 Manufact'd Gas - Gas Holders	2,852	-	-	-	-	-	-	2,852	2,852
26	436-00 Manufact'd Gas - Compressor Equipment	355	-	-	-	-	-	-	355	355
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	735	-	-	-	-	-	-	735	735
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499	16,499
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	25,014	-	1,550	48	524	-	-	27,136	26,075
36	TOTAL MANUFACTURED	67,023	-	1,760	48	595	-	-	69,426	68,225

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 32

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402	$ 7,402
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,299	-	-	-	-	-	-	16,299	16,299
6	463-00 Measuring Structures	5,511	-	-	-	-	(21)	-	5,490	5,501
7	464-00 Other Structures & Improvements	6,023	-	50	-	17	(29)	-	6,061	6,042
8	465-00 Mains	799,512	-	20,606	861	6,964	(374)	-	827,569	813,541
9	465-00 Mains - INSPECTION	5,803	-	4,943	-	1,671	(1,268)	-	11,149	8,476
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974	974
13	466-00 Compressor Equipment	111,811	-	1,746	83	590	(340)	-	113,890	112,851
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,249	-	-	-	-	(131)	-	30,118	30,184
17	467-10 Telemetering	9,293	-	220	10	74	(22)	-	9,575	9,434
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346	346
21	TOTAL TRANSMISSION	995,547	-	27,565	954	9,316	(2,185)	-	1,031,197	1,013,372
22										
23	**DISTRIBUTION PLANT**									
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	18,219	-	-	-	-	(21)	-	18,198	18,209
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107	107
28	473-00 Services	758,346	-	23,241	-	7,856	(3,185)	-	786,258	772,302
29	473-00 Services - LILO	-	-	-	-	-	-	-	-	-
30	474-00 House Regulators & Meter Installations	174,943	-	-	-	-	(284)	-	174,659	174,801
31	474-00 House Regulators & Meter Installations - LILO	-	-	-	-	-	-	-	-	-
32	477-00 Meters/Regulators Installations	18,871	-	15,570	-	5,263	-	-	39,704	29,288
33	475-00 Mains	947,273	-	22,462	173	7,593	(1,049)	-	976,452	961,863
34	475-00 Mains - LILO	-	-	-	-	-	-	-	-	-
35	476-00 Compressor Equipment	1,450	-	-	-	-	-	(623)	827	827
36	477-00 Measuring & Regulating Equipment	88,594	-	5,845	278	1,976	(598)	-	96,095	92,345
37	477-00 Telemetering	7,102	-	644	5	218	(6)	-	7,963	7,533
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163	163
39	478-10 Meters	207,016	-	13,250	-	-	(6,353)	-	213,913	210,465
40	478-11 Meters - LILO	-	-	-	-	-	-	-	-	-
41	478-20 Instruments	11,889	-	-	-	-	-	-	11,889	11,889
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,237,368	-	81,012	456	22,906	(11,496)	(623)	2,329,623	2,283,184
44										
45	**BIO GAS**									
46	472-00 Bio Gas Struct. & Improvements	137	-	-	-	-	-	-	137	137
47	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80	80
48	475-20 Bio Gas Mains – Private Land	41	-	220	-	74	-	-	335	188
49	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-	-
50	418-20 Bio Gas Purification Upgrader	-	-	-	-	-	-	-	-	-
51	477-10 Bio Gas Reg & Meter Equipment	280	-	440	-	149	-	-	869	575
52	478-30 Bio Gas Meters	7	-	440	-	-	-	-	447	227
53	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22	22
54	TOTAL BIO-GAS	567	-	1,100	-	223	-	-	1,890	1,229

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 33

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	CPCN'S	2013 Additions	2013 AFUDC	2013 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2013	Mid-year GPIS for Depreciation
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Natural Gas for Transportation**									
2	476-10 NG Transportation CNG Dispensing Equipment	$ 2,554	$ -	$ -	$ -	$ -	$ -	$ (2,554)	$ -	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	47	-	-	-	-	-	(47)	-	-
4	476-30 NG Transportation CNG Foundations	471	-	-	-	-	-	(471)	-	-
5	476-40 NG Transportation LNG Foundations	4	-	-	-	-	-	(4)	-	-
6	476-50 NG Transportation LNG Pumps	-	-	-	-	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	119	-	-	-	-	-	(119)	-	-
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	3,195	-	-	-	-	-	(3,195)	-	-
10										
11	**GENERAL PLANT & EQUIPMENT**									
12	480-00 Land in Fee Simple	22,329	-	321	-	-	-	-	22,650	22,490
13	481-00 Land Rights	-	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-	-
15	- Frame Buildings	10,770	-	-	-	-	-	-	10,770	10,770
16	- Masonry Buildings	92,527	-	4,974	-	-	-	-	97,501	95,014
17	- Leasehold Improvement	3,822	-	163	-	-	(151)	-	3,834	3,828
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,479	-	478	-	-	(303)	-	3,654	3,567
20	483-40 GP Furniture	21,395	-	1,613	-	-	(1,954)	-	21,054	21,225
21	483-10 GP Computer Hardware	29,627	-	8,640	231	-	(6,489)	-	32,009	30,818
22	483-20 GP Computer Software	3,405	-	-	-	-	(192)	-	3,213	3,309
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,208	-	-	-	-	-	-	2,208	2,208
26	484-00 Vehicles - Leased	28,385	-	2,400	-	-	(1,440)	-	29,345	28,865
27	485-10 Heavy Work Equipment	664	-	-	-	-	-	-	664	664
28	485-20 Heavy Mobile Equipment	838	-	-	-	-	-	-	838	838
29	486-00 Small Tools & Equipment	38,733	-	2,855	-	-	(963)	-	40,625	39,679
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-	-
33	- Telephone	7,679	-	-	-	-	(906)	-	6,773	7,226
34	- Radio	4,856	-	1,020	-	-	(34)	-	5,842	5,349
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	270,741	-	22,464	231	-	(12,432)	-	281,004	275,873
37										
38	**UNCLASSIFIED PLANT**									
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-	-
41										
42	TOTAL CAPITAL	$ 3,726,853	$ -	$ 147,254	$ 1,954	$ 33,040	$ (35,125)	$ (3,818)	$ 3,870,158	$ 3,796,597
43		- Appendix G2-FORECAST, Sch 28								
44	Cross Reference			- Appendix G2-FORECAST, Sch 30					- Appendix G2-FORECAST, Sch 28	
45			- Appendix G2-FORECAST, Sch 30			- Appendix G2-FORECAST, Sch 30				

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

GAS PLANT IN SERVICE CONTINUITY SCHEDULE

FOR THE YEAR ENDING DECEMBER 31, 2014

($000s)

Schedule 34

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**INTANGIBLE PLANT**								
2	117-00 Utility Plant Acquisition Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	-	-	-	-	-	-	109
4	175-00 Unamortized Conversion Expense - Squamish	777	-	-	-	-	-	-	777
5	178-00 Organization Expense	728	-	-	-	-	-	-	728
6	179-01 Other Deferred Charges	-	-	-	-	-	-	-	-
7	401-00 Franchise and Consents	99	-	-	-	-	-	-	99
8	402-00 Utility Plant Acquisition Adjustment	62	-	-	-	-	-	-	62
9	402-00 Other Intangible Plant	688	-	-	-	-	-	-	688
10	431-00 Mfg'd Gas Land Rights	-	-	-	-	-	-	-	-
11	461-00 Transmission Land Rights	44,922	-	109	-	-	-	-	45,031
12	461-10 Transmission Land Rights - Byron Creek	16	-	-	-	-	-	-	16
13	461-13 IP Land Rights Whistler	-	-	-	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	-	-	-	-	-	-	1,209
15	471-10 Distribution Land Rights - Byron Creek	1	-	-	-	-	-	-	1
16	402-01 Application Software - 12.5%	86,104	-	6,033	176	-	(3,738)	-	88,575
17	402-02 Application Software - 20%	22,303	-	6,033	120	-	(2,317)	-	26,139
18	TOTAL INTANGIBLE	157,018	-	12,175	296	-	(6,055)	-	163,434
19									
20	**MANUFACTURED GAS / LOCAL STORAGE**								
21	430-00 Manufact'd Gas - Land	31	-	-	-	-	-	-	31
22	431-00 Manufact'd Gas - Land Rights	-	-	-	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	-	-	-	-	-	-	965
24	433-00 Manufact'd Gas - Equipment	729	-	105	-	38	-	-	872
25	434-00 Manufact'd Gas - Gas Holders	2,852	-	-	-	-	-	-	2,852
26	436-00 Manufact'd Gas - Compressor Equipment	355	-	-	-	-	-	-	355
27	437-00 Manufact'd Gas - Measuring & Regulating Equipmer	735	-	-	-	-	-	-	735
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	-	-	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	-	-	15,164
30	442-00 Structures & Improvements (Tilbury)	4,960	-	-	-	-	-	-	4,960
31	443-00 Gas Holders - Storage (Tilbury)	16,499	-	-	-	-	-	-	16,499
32	446-00 Compressor Equipment (Tilbury)	-	-	-	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	-	-	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	-	-	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	27,136	-	3,433	133	1,249	-	-	31,951
36	TOTAL MANUFACTURED	69,426	-	3,538	133	1,287	-	-	74,384

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**TRANSMISSION PLANT**								
2	460-00 Land in Fee Simple	$ 7,402	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,402
3	461-00 Transmission Land Rights	-	-	-	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	-	-	-	-	-	-	-
5	462-00 Compressor Structures	16,299	-	-	-	-	-	-	16,299
6	463-00 Measuring Structures	5,490	-	-	-	-	(21)	-	5,469
7	464-00 Other Structures & Improvements	6,061	-	-	-	-	-	-	6,061
8	465-00 Mains	827,569	-	9,064	373	3,300	(374)	-	839,932
9	465-00 Mains - INSPECTION	11,149	-	2,098	-	763	(368)	-	13,642
10	465-11 IP Transmission Pipeline - Whistler	-	-	-	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	-	-	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	-	-	-	-	-	-	974
13	466-00 Compressor Equipment	113,890	-	1,532	70	558	(299)	-	115,751
14	466-00 Compressor Equipment - OVERHAUL	2,285	-	-	-	-	-	-	2,285
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	-	-	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,118	-	-	-	-	(131)	-	29,987
17	467-10 Telemetering	9,575	-	319	13	116	(32)	-	9,991
18	467-31 IP Intermediate Pressure Whistler	-	-	-	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	-	-	-	-	-	-	39
20	468-00 Communication Structures & Equipment	346	-	-	-	-	-	-	346
21	TOTAL TRANSMISSION	1,031,197	-	13,013	456	4,737	(1,225)	-	1,048,178
22									
23	**DISTRIBUTION PLANT**								
24	470-00 Land in Fee Simple	3,395	-	-	-	-	-	-	3,395
25	471-00 Distribution Land Rights	-	-	-	-	-	-	-	-
26	472-00 Structures & Improvements	18,198	-	-	-	-	(21)	-	18,177
27	472-10 Structures & Improvements - Byron Creek	107	-	-	-	-	-	-	107
28	473-00 Services	786,258	-	25,031	-	9,110	(3,185)	-	817,214
29	473-00 Services - LILO	-	-	-	-	-	-	-	-
30	474-00 House Regulators & Meter Installations	174,659	-	-	-	-	(6)	-	174,653
31	474-00 House Regulators & Meter Installations - LILO	-	-	-	-	-	-	-	-
32	477-00 Meters/Regulators Installations	39,704	-	13,813	97	5,027	-	-	58,641
33	475-00 Mains	976,452	-	26,178	141	9,526	(1,049)	-	1,011,248
34	475-00 Mains - LILO	-	-	-	-	-	-	-	-
35	476-00 Compressor Equipment	827	-	-	-	-	-	-	827
36	477-00 Measuring & Regulating Equipment	96,095	-	8,058	389	2,932	(598)	-	106,876
37	477-00 Telemetering	7,963	-	287	2	105	(6)	-	8,351
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	-	-	-	-	-	-	163
39	478-10 Meters	213,913	-	13,813	-	-	(6,672)	-	221,054
40	478-11 Meters - LILO	-	-	-	-	-	-	-	-
41	478-20 Instruments	11,889	-	-	-	-	-	-	11,889
42	479-00 Other Distribution Equipment	-	-	-	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,329,623	-	87,180	629	26,700	(11,537)	-	2,432,595
44									
45	**BIO GAS**								
46	472-00 Bio Gas Struct. & Improvements	137	-	-	-	-	-	-	137
47	475-10 Bio Gas Mains – Municipal Land	80	-	-	-	-	-	-	80
48	475-20 Bio Gas Mains – Private Land	335	-	794	-	289	-	-	1,418
49	418-10 Bio Gas Purification Overhaul	-	-	-	-	-	-	-	-
50	418-20 Bio Gas Purification Upgrader	-	-	-	-	-	-	-	-
51	477-10 Bio Gas Reg & Meter Equipment	869	-	1,588	-	578	-	-	3,035
52	478-30 Bio Gas Meters	447	-	1,588	-	-	-	-	2,035
53	474-10 Bio Gas Reg & Meter Installations	22	-	-	-	-	-	-	22
54	TOTAL BIO-GAS	1,890	-	3,970	-	867	-	-	6,727

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 36

GAS PLANT IN SERVICE CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	CPCN'S	2014 Additions	2014 AFUDC	2014 CapOH	Retirements	Transfers/ Recovery	Balance 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Natural Gas for Transportation**								
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	-	-	-	-	-	-	-	-
4	476-30 NG Transportation CNG Foundations	-	-	-	-	-	-	-	-
5	476-40 NG Transportation LNG Foundations	-	-	-	-	-	-	-	-
6	476-50 NG Transportation LNG Pumps	-	-	-	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	-	-	-	-	-	-	-	-
8	476-70 NG Transportation LNG Dehydrator	-	-	-	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-	-	-	-	-	-	-	-
10									
11	**GENERAL PLANT & EQUIPMENT**								
12	480-00 Land in Fee Simple	22,650	-	-	-	-	-	-	22,650
13	481-00 Land Rights	-	-	-	-	-	-	-	-
14	482-00 Structures & Improvements	-	-	-	-	-	-	-	-
15	- Frame Buildings	10,770	-	-	-	-	-	-	10,770
16	- Masonry Buildings	97,501	-	3,276	-	-	-	-	100,777
17	- Leasehold Improvement	3,834	-	274	-	-	(40)	-	4,068
18	Office Equipment & Furniture	-	-	-	-	-	-	-	-
19	483-30 GP Office Equipment	3,654	-	51	-	-	(92)	-	3,613
20	483-40 GP Furniture	21,054	-	305	-	-	(3,123)	-	18,236
21	483-10 GP Computer Hardware	32,009	-	8,044	218	-	(3,708)	-	36,563
22	483-20 GP Computer Software	3,213	-	-	-	-	(44)	-	3,169
23	483-21 GP Computer Software	-	-	-	-	-	-	-	-
24	483-22 GP Computer Software	-	-	-	-	-	-	-	-
25	484-00 Vehicles	2,208	-	2,600	-	-	-	-	4,808
26	484-00 Vehicles - Leased	29,345	-	-	-	-	(1,536)	-	27,809
27	485-10 Heavy Work Equipment	664	-	-	-	-	-	-	664
28	485-20 Heavy Mobile Equipment	838	-	-	-	-	-	-	838
29	486-00 Small Tools & Equipment	40,625	-	2,915	-	-	(2,003)	-	41,537
30	487-00 Equipment on Customer's Premises	24	-	-	-	-	-	-	24
31	- VRA Compressor Installation Costs	-	-	-	-	-	-	-	-
32	488-00 Communications Equipment	-	-	-	-	-	-	-	-
33	- Telephone	6,773	-	-	-	-	(1,460)	-	5,313
34	- Radio	5,842	-	1,244	-	-	(214)	-	6,872
35	489-00 Other General Equipment	-	-	-	-	-	-	-	-
36	TOTAL GENERAL	281,004	-	18,709	218	-	(12,220)	-	287,711
37									
38	**UNCLASSIFIED PLANT**								
39	499-00 Plant Suspense	-	-	-	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-	-	-	-	-	-	-	-
41									
42	TOTAL CAPITAL	$ 3,870,158	$ -	$ 138,585	$ 1,732	$ 33,591	$ (31,037)	$ -	$ 4,013,029
43		- Appendix G2-FORECAST, Sch 29							
44	Cross Reference			- Appendix G2-FORECAST, Sch 30					- Appendix G2-FORECAST, Sch 29
45			- Appendix G2-FORECAST, Sch 30			- Appendix G2-FORECAST, Sch 30			

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 37

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	548	549
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	-	78
5	178-00 Organization Expense	728	1.00%	7	-	-	391	398
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	1	-	-	98	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	227	243
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,726	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	85,788	12.50%	10,724	-	(6,015)	23,581	28,290
17	402-02 Application Software - 20%	20,513	20.00%	4,103	-	(2,997)	7,243	8,349
18	TOTAL INTANGIBLE	154,715		14,930	-	(9,012)	32,839	38,757
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	3.38%	33	-	-	143	176
24	433-00 Manufact'd Gas - Equipment	589	6.63%	39	-	-	88	127
25	434-00 Manufact'd Gas - Gas Holders	2,852	2.35%	67	-	-	238	305
26	436-00 Manufact'd Gas - Compressor Equipment	355	5.16%	18	-	-	38	56
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	735	15.89%	117	-	-	363	480
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,789	2,966
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	10,721	11,039
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	26,075	4.24%	1,106	-	-	10,900	12,006
36	TOTAL MANUFACTURED	68,225		1,875	-	-	25,281	27,156

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account (1)	Mid-year GPIS for Depreciation (2)	Annual Depreciation Rate % (3)	2013 DEPRECIATION Provision (Cr.) (4)	Adjust-ments (5)	Retirements (6)	Accumulated 12/31/2012 (7)	Accumulated 12/31/2013 (8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,299	3.74%	610	-	-	6,790	7,400
6	463-00 Measuring Structures	5,501	3.80%	209	-	(17)	1,936	2,128
7	464-00 Other Structures & Improvements	6,042	2.83%	171	-	(29)	1,891	2,033
8	465-00 Mains	813,541	1.44%	11,715	-	(372)	214,894	226,237
9	465-00 Mains - INSPECTION	8,476	14.87%	1,260	-	(1,268)	1,851	1,843
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	-	-	937	986
13	466-00 Compressor Equipment	112,851	2.87%	3,239	-	(340)	44,521	47,420
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	298	400
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,184	4.27%	1,289	-	(108)	10,440	11,621
17	467-10 Telemetering	9,434	0.31%	29	-	(22)	6,316	6,323
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	-	-	3	3
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	328	343
21	TOTAL TRANSMISSION	1,013,372		18,688	-	(2,156)	290,606	307,138
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	18,209	3.33%	606	-	(13)	4,852	5,445
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	32	37
28	473-00 Services	772,302	2.53%	19,287	-	(1,132)	142,028	160,183
29	473-00 Services - LILO	-	1.97%	-	-	-	-	-
30	474-00 House Regulators & Meter Installations	174,801	7.62%	12,415	-	(227)	18,625	30,813
31	474-00 House Regulators & Meter Installations - LILO	-	1.97%	-	-	-	-	-
32	477-00 Meters/Regulators Installations	29,288	4.55%	1,333	-	-	206	1,539
33	475-00 Mains	961,863	1.59%	15,450	-	(501)	299,353	314,302
34	475-00 Mains - LILO	-	1.97%	-	-	-	-	-
35	476-00 Compressor Equipment	827	26.54%	219	(291)	-	1,235	1,163
36	477-00 Measuring & Regulating Equipment	92,345	4.75%	4,386	-	(436)	25,902	29,852
37	477-00 Telemetering	7,533	0.25%	19	-	(2)	6,063	6,080
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	212	212
39	478-10 Meters	210,465	8.05%	16,327	-	(3,492)	75,361	88,196
40	478-11 Meters - LILO	-	1.97%	-	-	-	-	-
41	478-20 Instruments	11,889	3.15%	375	-	-	1,299	1,674
42	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,283,184		70,422	(291)	(5,803)	575,194	639,522
44								
45	**BIO GAS**							
46	472-00 Bio Gas Struct. & Improvements	137	3.60%	5	-	-	11	16
47	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	4	5
48	475-20 Bio Gas Mains – Private Land	188	1.48%	3	-	-	1	4
49	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
50	418-20 Bio Gas Purification Upgrader	-	6.67%	-	-	-	-	-
51	477-10 Bio Gas Reg & Meter Equipment	575	4.75%	27	-	-	28	55
52	478-30 Bio Gas Meters	227	8.05%	18	-	-	1	19
53	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	2	2
54	TOTAL BIO-GAS	1,229		54	-	-	47	101

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Depreciation Rate %	2013 DEPRECIATION Provision (Cr.)	2013 DEPRECIATION Adjust-ments	2013 DEPRECIATION Retirements	Accumulated 12/31/2012	Accumulated 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	5.00%	$ -	$ (135)	$ -	135	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	-	5.00%	-	(4)	-	4	-
4	476-30 NG Transportation CNG Foundations	-	5.00%	-	(80)	-	80	-
5	476-40 NG Transportation LNG Foundations	-	5.00%	-	(2)	-	2	-
6	476-50 NG Transportation LNG Pumps	-	10.00%	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	-	5.00%	-	(6)	-	6	-
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-		-	(227)	-	227	-
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,490	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	10,770	4.82%	519	-	-	2,912	3,431
16	- Masonry Buildings	95,014	2.23%	2,119	-	-	15,696	17,815
17	- Leasehold Improvement	3,828	10.00%	405	-	(151)	565	819
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,567	6.67%	238	-	(245)	1,554	1,547
20	483-40 GP Furniture	21,225	5.00%	1,061	-	(1,954)	12,884	11,991
21	483-10 GP Computer Hardware	30,818	20.00%	6,163	-	(6,489)	12,281	11,955
22	483-20 GP Computer Software	3,309	12.50%	414	-	(192)	1,146	1,368
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,208	5.16%	114	-	-	601	715
26	484-00 Vehicles - Leased	28,865	0.00%	3,845	-	(1,440)	14,556	16,961
27	485-10 Heavy Work Equipment	664	8.96%	60	-	-	(175)	(115)
28	485-20 Heavy Mobile Equipment	838	18.06%	151	-	-	753	904
29	486-00 Small Tools & Equipment	39,679	5.00%	1,984	-	(963)	17,124	18,145
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	12	14
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	7,226	6.67%	482	-	(797)	4,368	4,053
34	- Radio	5,349	6.67%	357	-	(34)	2,678	3,001
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	275,873		17,914	-	(12,265)	86,985	92,634
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,796,597		$ 123,883	$ (518)	$ (29,236)	$ 1,011,179	$ 1,105,308
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,354)				
45	Add: Depreciation variance adjustment			1,314				
46	**Net Depreciation Expense**			$ 123,842				
47		- Appendix G2-FORECAST, Sch 33						
48	Cross Reference			- Appendix G2-FORECAST, Sch 20			- Appendix G2-FORECAST, Sch 28	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE Schedule 40

FOR THE YEAR ENDING DECEMBER 31, 2014

($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**INTANGIBLE PLANT**							
2	117-00 Utility Plant Acquisition Adjustment	$ -	0.00%	$ -	$ -	$ -	$ -	$ -
3	175-00 Unamortized Conversion Expense	109	1.00%	1	-	-	549	550
4	175-00 Unamortized Conversion Expense - Squamish	777	10.00%	78	-	-	78	156
5	178-00 Organization Expense	728	1.00%	7	-	-	398	405
6	179-01 Other Deferred Charges	-	0.00%	-	-	-	-	-
7	401-00 Franchise and Consents	99	49.19%	-	-	-	99	99
8	402-00 Utility Plant Acquisition Adjustment	62	57.14%	-	-	-	62	62
9	402-00 Other Intangible Plant	688	2.38%	16	-	-	243	259
10	431-00 Mfg'd Gas Land Rights	-	0.00%	-	-	-	-	-
11	461-00 Transmission Land Rights	44,922	0.00%	-	-	-	667	667
12	461-10 Transmission Land Rights - Byron Creek	16	0.00%	-	-	-	19	19
13	461-13 IP Land Rights Whistler	-	0.00%	-	-	-	-	-
14	471-00 Distribution Land Rights	1,209	0.00%	-	-	-	2	2
15	471-10 Distribution Land Rights - Byron Creek	1	0.00%	-	-	-	1	1
16	402-01 Application Software - 12.5%	86,104	12.50%	10,763	-	(3,738)	28,290	35,315
17	402-02 Application Software - 20%	22,303	20.00%	4,461	-	(2,317)	8,349	10,493
18	TOTAL INTANGIBLE	157,018		15,326	-	(6,055)	38,757	48,028
19								
20	**MANUFACTURED GAS / LOCAL STORAGE**							
21	430-00 Manufact'd Gas - Land	31	0.00%	-	-	-	-	-
22	431-00 Manufact'd Gas - Land Rights	-	0.00%	-	-	-	-	-
23	432-00 Manufact'd Gas - Struct. & Improvements	965	3.38%	33	-	-	176	209
24	433-00 Manufact'd Gas - Equipment	729	6.63%	48	-	-	127	175
25	434-00 Manufact'd Gas - Gas Holders	2,852	2.35%	67	-	-	305	372
26	436-00 Manufact'd Gas - Compressor Equipment	355	5.16%	18	-	-	56	74
27	437-00 Manufact'd Gas - Measuring & Regulating Equipment	735	15.89%	117	-	-	480	597
28	443-00 Gas Holders - Storage (non-Tilbury, non-Mt. Hayes)	-	0.00%	-	-	-	-	-
29	440/441-00 Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	-	-	-	1	1
30	442-00 Structures & Improvements (Tilbury)	4,960	3.57%	177	-	-	2,966	3,143
31	443-00 Gas Holders - Storage (Tilbury)	16,499	1.93%	318	-	-	11,039	11,357
32	446-00 Compressor Equipment (Tilbury)	-	0.00%	-	-	-	-	-
33	447-00 Measuring & Regulating Equipment (Tilbury)	-	0.00%	-	-	-	-	-
34	448-00 Purification Equipment (Tilbury)	-	0.00%	-	-	-	-	-
35	449-00 Local Storage Equipment (Tilbury)	27,136	4.24%	1,151	-	-	12,006	13,157
36	TOTAL MANUFACTURED	69,426		1,929	-	-	27,156	29,085

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued) Schedule 41

FOR THE YEAR ENDING DECEMBER 31, 2014

($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**TRANSMISSION PLANT**							
2	460-00 Land in Fee Simple	$ 7,402	0.00%	$ -	$ -	$ -	$ 401	$ 401
3	461-00 Transmission Land Rights	-	0.00%	-	-	-	-	-
4	461-02 Land Rights - Mt. Hayes	-	0.00%	-	-	-	-	-
5	462-00 Compressor Structures	16,299	3.74%	610	-	-	7,400	8,010
6	463-00 Measuring Structures	5,490	3.80%	209	-	(17)	2,128	2,320
7	464-00 Other Structures & Improvements	6,061	2.83%	172	-	-	2,033	2,205
8	465-00 Mains	827,569	1.44%	11,917	-	(372)	226,237	237,782
9	465-00 Mains - INSPECTION	11,149	14.87%	1,658	-	(368)	1,843	3,133
10	465-11 IP Transmission Pipeline - Whistler	-	0.00%	-	-	-	-	-
11	465-30 Mt Hayes - Mains	-	0.00%	-	-	-	-	-
12	465-10 Mains - Byron Creek	974	5.00%	49	-	-	986	1,035
13	466-00 Compressor Equipment	113,890	2.87%	3,269	-	(299)	47,420	50,390
14	466-00 Compressor Equipment - OVERHAUL	2,285	4.47%	102	-	-	400	502
15	467-00 Mt. Hayes - Measuring and Regulating Equipment	-	0.00%	-	-	-	-	-
16	467-00 Measuring & Regulating Equipment	30,118	4.27%	1,286	-	(108)	11,621	12,799
17	467-10 Telemetering	9,575	0.31%	30	-	(32)	6,323	6,321
18	467-31 IP Intermediate Pressure Whistler	-	0.00%	-	-	-	-	-
19	467-20 Measuring & Regulating Equipment - Byron Creek	39	0.00%	-	-	-	3	3
20	468-00 Communication Structures & Equipment	346	4.37%	15	-	-	343	358
21	TOTAL TRANSMISSION	1,031,197		19,317	-	(1,196)	307,138	325,259
22								
23	**DISTRIBUTION PLANT**							
24	470-00 Land in Fee Simple	3,395	0.00%	-	-	-	26	26
25	471-00 Distribution Land Rights	-	0.00%	-	-	-	-	-
26	472-00 Structures & Improvements	18,198	3.33%	606	-	(13)	5,445	6,038
27	472-10 Structures & Improvements - Byron Creek	107	5.00%	5	-	-	37	42
28	473-00 Services	786,258	2.53%	19,640	-	(1,132)	160,183	178,691
29	473-00 Services - LILO	-	1.97%	-	-	-	-	-
30	474-00 House Regulators & Meter Installations	174,659	7.62%	12,404	-	(4)	30,813	43,213
31	474-00 House Regulators & Meter Installations - LILO	-	1.97%	-	-	-	-	-
32	477-00 Meters/Regulators Installations	39,704	4.55%	1,806	-	-	1,539	3,345
33	475-00 Mains	976,452	1.59%	15,682	-	(501)	314,302	329,483
34	475-00 Mains - LILO	-	1.97%	-	-	-	-	-
35	476-00 Compressor Equipment	827	26.54%	219	-	-	1,163	1,382
36	477-00 Measuring & Regulating Equipment	96,095	4.75%	4,564	-	(436)	29,852	33,980
37	477-00 Telemetering	7,963	0.25%	20	-	(2)	6,080	6,098
38	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	212	212
39	478-10 Meters	213,913	8.05%	16,605	-	(3,667)	88,196	101,134
40	478-11 Meters - LILO	-	1.97%	-	-	-	-	-
41	478-20 Instruments	11,889	3.15%	375	-	-	1,674	2,049
42	479-00 Other Distribution Equipment	-	0.00%	-	-	-	-	-
43	TOTAL DISTRIBUTION	2,329,623		71,926	-	(5,755)	639,522	705,693
44								
45	**BIO GAS**							
46	472-00 Bio Gas Struct. & Improvements	137	3.60%	5	-	-	16	21
47	475-10 Bio Gas Mains – Municipal Land	80	1.48%	1	-	-	5	6
48	475-20 Bio Gas Mains – Private Land	335	1.48%	5	-	-	4	9
49	418-10 Bio Gas Purification Overhaul	-	13.33%	-	-	-	-	-
50	418-20 Bio Gas Purification Upgrader	-	6.67%	-	-	-	-	-
51	477-10 Bio Gas Reg & Meter Equipment	869	4.75%	41	-	-	55	96
52	478-30 Bio Gas Meters	447	8.05%	36	-	-	19	55
53	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	2	2
54	TOTAL BIO-GAS	1,890		88	-	-	101	189

FORTISBC ENERGY INC.

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FORECAST
Schedule 42

DEPRECIATION AND AMORTIZATION CONTINUITY SCHEDULE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Depreciation Rate %	2014 DEPRECIATION Provision (Cr.)	Adjust-ments	Retirements	Accumulated 12/31/2013	Accumulated 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Natural Gas for Transportation**							
2	476-10 NG Transportation CNG Dispensing Equipment	$ -	5.00%	$ -	$ -	$ -	$ -	$ -
3	476-20 NG Transportation LNG Dispensing Equipment	-	5.00%	-	-	-	-	-
4	476-30 NG Transportation CNG Foundations	-	5.00%	-	-	-	-	-
5	476-40 NG Transportation LNG Foundations	-	5.00%	-	-	-	-	-
6	476-50 NG Transportation LNG Pumps	-	10.00%	-	-	-	-	-
7	476-60 NG Transportation CNG Dehydrator	-	5.00%	-	-	-	-	-
8	476-70 NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-
9	TOTAL NG FOR TRANSP	-		-	-	-	-	-
10								
11	**GENERAL PLANT & EQUIPMENT**							
12	480-00 Land in Fee Simple	22,650	0.00%	-	-	-	30	30
13	481-00 Land Rights	-	0.00%	-	-	-	-	-
14	482-00 Structures & Improvements	-	0.00%	-	-	-	-	-
15	- Frame Buildings	10,770	4.82%	519	-	-	3,431	3,950
16	- Masonry Buildings	97,501	2.23%	2,174	-	-	17,815	19,989
17	- Leasehold Improvement	3,834	10.00%	383	-	(40)	819	1,162
18	Office Equipment & Furniture	-	0.00%	-	-	-	-	-
19	483-30 GP Office Equipment	3,654	6.67%	244	-	(69)	1,547	1,722
20	483-40 GP Furniture	21,054	5.00%	1,053	-	(3,123)	11,991	9,921
21	483-10 GP Computer Hardware	32,009	20.00%	6,402	-	(3,708)	11,955	14,649
22	483-20 GP Computer Software	3,213	12.50%	402	-	(44)	1,368	1,726
23	483-21 GP Computer Software	-	20.00%	-	-	-	-	-
24	483-22 GP Computer Software	-	0.00%	-	-	-	-	-
25	484-00 Vehicles	2,208	12.50%	276	-	-	715	991
26	484-00 Vehicles - Leased	29,345	0.00%	2,755	-	(1,536)	16,961	18,180
27	485-10 Heavy Work Equipment	664	8.96%	60	-	-	(115)	(55)
28	485-20 Heavy Mobile Equipment	838	18.06%	151	-	-	904	1,055
29	486-00 Small Tools & Equipment	40,625	5.00%	2,031	-	(2,003)	18,145	18,173
30	487-00 Equipment on Customer's Premises	24	6.67%	2	-	-	14	16
31	- VRA Compressor Installation Costs	-	0.00%	-	-	-	-	-
32	488-00 Communications Equipment	-	0.00%	-	-	-	-	-
33	- Telephone	6,773	6.67%	452	-	(1,314)	4,053	3,191
34	- Radio	5,842	6.67%	390	-	(214)	3,001	3,177
35	489-00 Other General Equipment	-	0.00%	-	-	-	-	-
36	TOTAL GENERAL	281,004		17,294	-	(12,051)	92,634	97,877
37								
38	**UNCLASSIFIED PLANT**							
39	499-00 Plant Suspense	-	0.00%	-	-	-	-	-
40	TOTAL UNCLASSIFIED	-		-	-	-	-	-
41								
42	TOTALS	$ 3,870,158		$ 125,880	$ -	$ (25,057)	$ 1,105,308	$ 1,206,131
43								
44	Less: Vehicle Depreciation Allocated To Capital Projects			(1,121)				
45				-				
46	**Net Depreciation Expense**			$ 124,759				
47		- Appendix G2-FORECAST, Sch 36						
48	Cross Reference			- Appendix G2-FORECAST, Sch 21			- Appendix G2-FORECAST, Sch 29	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

CONTRIBUTIONS IN AID OF CONSTRUCTION Schedule 43

FOR THE YEAR ENDING DECEMBER 31, 2013

($000s)

Line No.	Particulars	Balance 12/31/2012	Adjustment	2013 PROJECTED Additions	Retirements	Balance 12/31/2013	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 145,014	$ -	$ 6,451	$ -	$ 151,465	
4							
5	Transmission Contributions	29,058	-	2,425	-	31,483	
6							
7	Others	714	-	-	-	714	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,759	-	-	-	10,759	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	185,545	-	8,876	-	194,421	- Appendix G2-FORECAST, Sch 28
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(42,313)	-	(4,283)	-	(46,596)	
21							
22	Transmission Contributions	(2,335)	-	(507)	-	(2,842)	
23							
24	Others	(97)	-	(97)	-	(194)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(6,398)	-	(1,332)	-	(7,730)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(51,143)	-	(6,219)	-	(57,362)	- Appendix G2-FORECAST, Sch 28
32							
33	**NET CONTRIBUTIONS**	$ 134,402	$ -	$ 2,657	$ -	$ 137,059	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,219)			
37	Add: Depreciation Variance Adjustment			(280)			
38	**Net Amortization Expense**			$ (6,499)			- Appendix G2-FORECAST, Sch 20
39							
40							

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 44

CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Balance 12/31/2013	Adjustment	2014 FORECAST Additions	2014 FORECAST Retirements	Balance 12/31/2014	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**CIAC**						
2							
3	Distribution Contributions	$ 151,465	$ -	$ 5,619	$ -	$ 157,084	
4							
5	Transmission Contributions	31,483	-	203	-	31,686	
6							
7	Others	714	-	-	-	714	
8							
9	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
10	- Infrastructure/Custom	10,759	-	-	(3,768)	6,991	
11							
12	Biomethane	-	-	-	-	-	
13							
14	TOTAL Contributions	194,421	-	5,822	(3,768)	196,475	- Appendix G2-FORECAST, Sch 29
15							
16							
17							
18	**Amortization**						
19							
20	Distribution Contributions	(46,596)	-	(4,376)	-	(50,972)	
21							
22	Transmission Contributions	(2,842)	-	(528)	-	(3,370)	
23							
24	Others	(194)	-	(97)	-	(291)	
25							
26	Software Tax Savings - Non-Infrastructure	-	-	-	-	-	
27	- Infrastructure/Custom	(7,730)	-	(1,319)	3,768	(5,281)	
28							
29	Biomethane	-	-	-	-	-	
30							
31	TOTAL CIAC Amortization	(57,362)	-	(6,320)	3,768	(59,914)	- Appendix G2-FORECAST, Sch 29
32							
33	**NET CONTRIBUTIONS**	$ 137,059	$ -	$ (498)	$ -	$ 136,561	
34							
35							
36	Total CIAC Amortization Expense per Line 31			(6,320)			
37	Less: Depreciation & Amortization transferred to Biomethane BVA			-			
38	**Net Amortization Expense**			$ (6,320)			- Appendix G2-FORECAST, Sch 21
39							
40							

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ (10,042)	$ -	$ 29,657	$ (7,414)	$ 22,243	$ -	$ -	$ -	$ 12,201	$ 1,079
3	Midstream Cost Reconciliation Account (MCRA)	(17,844)	-	5,507	(1,377)	4,130	-	8,999	(2,250)	(6,965)	(12,404)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(24,583)	-	(6,666)	1,667	(5,000)	-	11,551	(2,888)	(20,919)	(22,751)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,125)	-	(1,179)	295	(884)	(10)	159	(40)	(4,900)	(4,512)
6	Revelstoke Propane Cost Deferral Account	(348)	-	269	(67)	202	-	-	-	(146)	(247)
7	SCP Mitigation Revenues Variance Account	(4,154)	-	-	-	-	2,926	-	-	(1,228)	(2,691)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	22,698	-	13,350	(3,338)	10,013	(3,152)	-	-	29,559	26,128
11	NGV Conversion Grants	37	-	15	(4)	11	(28)	-	-	21	29
12	Biomethane Program Costs	324	-	200	(50)	150	(172)	-	-	302	313
13	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
14	NGT Incentives	-	-	-	-	-	-	-	-	-	-
15	Fuelling Stations Variance Account	-	-	-	-	-	-	-	-	-	-
16											
17	Non-Controllable Items Deferral Accounts										
18	Property Tax Deferral	(2,868)	-	(3,150)	788	(2,363)	594	-	-	(4,637)	(3,752)
19	Insurance Variance	45	-	93	(23)	70	-	-	-	115	80
20	Pension & OPEB Variance	15,807	-	12,607	-	12,607	(3,205)	-	-	25,209	20,508
21	BCUC Levies Variance	449	-	923	(231)	692	-	-	-	1,141	795
22	Interest Variance	(5,699)	-	(130)	33	(98)	2,600	-	-	(3,197)	(4,448)
23	Interest Variance - Funding benefits via Customer Deposits	834	-	60	(15)	45	(309)	-	-	570	702
24	Tax Variance Account	597	-	1,274	(133)	1,141	-	-	-	1,738	1,168
25	Customer Service Variance Account	(5,548)	-	(10,285)	2,571	(7,714)	-	-	-	(13,262)	(9,405)
26	Pension & OPEB Funding	(171,550)	-	(8,176)	-	(8,176)	-	-	-	(179,726)	(175,638)
27	US GAAP Pension & OPEB Funded Status	139,153	-	(14,471)	-	(14,471)	-	-	-	124,682	131,918

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	Balance 12/31/2012	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries: Rider	Recoveries: Tax on Rider	Balance 12/31/2013	Mid-Year Average 2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	NGV for Transportation Application	140	-	50	(13)	38	(46)	-	-	132	136
4	Long Term Resource Plan Application	-	-	178	(45)	134	(90)	-	-	43	22
5	AES Inquiry Cost	619	-	2	(1)	2	(85)	-	-	536	577
6	Generic Cost of Capital Application	-	-	-	-	-	-	-	-	-	-
7	Amalgamation and Rate Design Application Costs	-	-	-	-	-	-	-	-	-	-
8											
9	Other Deferral Accounts										
10	2010-2011 Customer Service O&M and COS	21,613	-	-	-	-	(2,807)	-	-	18,806	20,210
11	Gas Asset Records Project	(60)	-	970	(243)	728	(567)	-	-	100	20
12	BC OneCall Project	(69)	-	961	(240)	721	(334)	-	-	318	125
13	Gains and Losses on Asset Disposition	27,090	-	5,890	-	5,890	(730)	-	-	32,250	29,670
14	Negative Salvage Provision/Cost	(5,965)	-	14,201	-	14,201	(16,933)	-	-	(8,697)	(7,331)
15	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
16											
17	Residual Deferred Accounts										
18	Depreciation Variance	(1,281)	-	636	-	636	-	-	-	(645)	(963)
19	SCP Tax Reassessment	(32)	-	-	-	-	-	-	-	(32)	(32)
20	BFI Costs and Recoveries	147	-	-	-	-	-	-	-	147	147
21	CNG and LNG Recoveries	(11)	-	(22)	6	(17)	-	-	-	(28)	(19)
22	2011 CNG and LNG Service Costs and Recoveries	(69)	-	-	-	-	34	-	-	(35)	(52)
23	Olympics Security Costs Deferral	188	-	-	-	-	(188)	-	-	-	94
24	IFRS Conversion Costs	238	-	-	-	-	(238)	-	-	-	119
25	2009 ROE & Cost of Capital Application	496	-	-	-	-	(168)	-	-	328	412
26	2012-2013 Revenue Requirement Application	614	-	-	-	-	(409)	-	-	205	409
27	CCE CPCN Application	150	-	-	-	-	(56)	-	-	94	122
28	Deferred Removal Costs	2,223	-	-	-	-	(2,354)	-	-	(131)	1,046
29	US GAAP Conversion Costs	(62)	-	-	-	-	(791)	-	-	(853)	(458)
30	US GAAP Transitional Costs	477	-	-	-	-	948	-	-	1,425	951
31	Earnings Sharing Mechanism	84	-	-	-	-	-	-	-	84	84
32	OH&M Recoveries from NGT	-	-	-	-	-	-	-	-	-	-
33	Tilbury Property Purchase (Subdividable Land)	-	-	-	-	-	-	-	-	-	-
34	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	-
35											
36	Total Deferred Charges for Rate Base	$ (20,287)	$ -	$ 42,765	$ (7,833)	$ 34,931	$ (25,569)	$ 20,709	$ (5,177)	$ 4,606	$ (7,840)
37											
38	Cross Reference						- Appendix G2-FORECAST, Sch 20				- Appendix G2-FORECAST, Sch 28

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 47

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries: Rider	Recoveries: Tax on Rider	Balance 12/31/2014	Mid-Year Average 2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Margin Related Deferral Accounts										
2	Commodity Cost Reconciliation Account (CCRA)	$ 12,201	$ -	$ (16,268)	$ 4,067	$ (12,201)	$ -	$ -	$ -	$ -	$ 6,100
3	Midstream Cost Reconciliation Account (MCRA)	(6,965)	-	-	-	-	-	4,643	(1,161)	(3,482)	(5,223)
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(20,919)	-	-	-	-	-	13,946	(3,487)	(10,460)	(15,690)
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(4,900)	-	1,571	(393)	1,178	388	210	(53)	(3,178)	(4,039)
6	Revelstoke Propane Cost Deferral Account	(146)	-	195	(49)	146	-	-	-	-	(73)
7	SCP Mitigation Revenues Variance Account	(1,228)	-	-	-	-	791	-	-	(437)	(833)
8											
9	Energy Policy Deferral Accounts										
10	Energy Efficiency & Conservation (EEC)	29,559	7,115	13,350	(3,338)	10,013	(3,801)	-	-	42,885	39,779
11	NGV Conversion Grants	21	-	15	(4)	11	(13)	-	-	19	20
12	Biomethane Program Costs	302	-	-	-	-	(302)	-	-	(0)	151
13	On-Bill Financing Pilot Program	-	-	-	-	-	-	-	-	-	-
14	NGT Incentives	-	27,117	10,974	(2,744)	8,231	(3,535)	-	-	31,812	29,465
15	Fuelling Stations Variance Account	-	288	238	(60)	179	(96)	-	-	370	329
16											
17	Non-Controllable Items Deferral Accounts										
18	Property Tax Deferral	(4,637)	-	-	-	-	1,941	-	-	(2,695)	(3,666)
19	Insurance Variance	115	-	-	-	-	(115)	-	-	-	57
20	Pension & OPEB Variance	25,209	-	-	-	-	(5,039)	-	-	20,170	22,690
21	BCUC Levies Variance	1,141	-	-	-	-	(1,141)	-	-	-	571
22	Interest Variance	(3,197)	-	-	-	-	2,680	-	-	(516)	(1,857)
23	Interest Variance - Funding benefits via Customer Deposits	570	-	-	-	-	(278)	-	-	293	431
24	Tax Variance Account	1,738	-	-	-	-	(579)	-	-	1,159	1,448
25	Customer Service Variance Account	(13,262)	-	-	-	-	2,652	-	-	(10,609)	(11,936)
26	Pension & OPEB Funding	(179,726)	-	9,636	-	9,636	-	-	-	(170,090)	(174,908)
27	US GAAP Pension & OPEB Funded Status	124,682	-	(9,300)	-	(9,300)	-	-	-	115,382	120,032

FORTISBC ENERGY INC.

June 10, 2013 Appendix G2
FORECAST
Schedule 48

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (Continued)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Forecast Balance 12/31/2013	Opening Bal. Transfer / Adjustment	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Recoveries Rider	Recoveries Tax on Rider	Balance 12/31/2014	Mid-Year Average 2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Application Costs Deferral Accounts										
2	2014-2018 PBR Requirements	$ -	$ 675	$ 100	$ (25)	$ 75	$ (150)	$ -	$ -	$ 600	$ 638
3	NGV for Transportation Application	132	-	-	-	-	(132)	-	-	-	66
4	Long Term Resource Plan Application	43	-	36	(9)	27	(57)	-	-	13	28
5	AES Inquiry Cost	536	-	-	-	-	(135)	-	-	400	468
6	Generic Cost of Capital Application	-	1,354	-	-	-	(677)	-	-	677	1,016
7	Amalgamation and Rate Design Application Costs	-	1,535	-	-	-	(512)	-	-	1,023	1,279
8											
9	Other Deferral Accounts										
10	2010-2011 Customer Service O&M and COS	18,806	-	-	-	-	(2,877)	-	-	15,930	17,368
11	Gas Asset Records Project	100	-	1,113	(278)	834	(187)	-	-	748	424
12	BC OneCall Project	318	-	579	(145)	434	(164)	-	-	588	453
13	Gains and Losses on Asset Disposition	32,250	-	5,981	-	5,981	(1,682)	-	-	36,549	34,399
14	Negative Salvage Provision/Cost	(8,697)	-	13,327	-	13,327	(17,262)	-	-	(12,631)	(10,664)
15	TESDA Overhead Allocation Variance	-	-	-	-	-	-	-	-	-	-
16											
17	Residual Deferred Accounts										
18	Depreciation Variance	(645)	-	-	-	-	645	-	-	-	(322)
19	SCP Tax Reassessment	(32)	-	-	-	-	32	-	-	-	(16)
20	BFI Costs and Recoveries	147	(147)	-	-	-	-	-	-	-	-
21	CNG and LNG Recoveries	(28)	-	-	-	-	28	-	-	-	(14)
22	2011 CNG and LNG Service Costs and Recoveries	(35)	-	-	-	-	35	-	-	-	(17)
23	Olympics Security Costs Deferral	-	-	-	-	-	-	-	-	-	-
24	IFRS Conversion Costs	-	-	-	-	-	-	-	-	-	-
25	2009 ROE & Cost of Capital Application	328	-	-	-	-	(328)	-	-	-	164
26	2012-2013 Revenue Requirement Application	205	-	-	-	-	(205)	-	-	0	102
27	CCE CPCN Application	94	-	-	-	-	(94)	-	-	-	47
28	Deferred Removal Costs	(131)	-	-	-	-	131	-	-	-	(66)
29	US GAAP Conversion Costs	(853)	-	-	-	-	853	-	-	-	(427)
30	US GAAP Transitional Costs	1,425	-	-	-	-	(1,425)	-	-	-	713
31	Earnings Sharing Mechanism	84	(84)	-	-	-	-	-	-	-	-
32	OH&M Recoveries from NGT	-	(189)	-	-	-	189	-	-	-	(95)
33	Tilbury Property Purchase (Subdividable Land)	-	(164)	-	-	-	164	-	-	-	(82)
34	Residual Delivery Rate Riders	-	(38)	-	-	-	38	-	-	-	(19)
35											
36	Total Deferred Charges for Rate Base	$ 4,606	$ 37,461	$ 31,546	$ (2,976)	$ 28,570	$ (30,216)	$ 18,799	$ (4,700)	$ 54,519	$ 48,293
37											
38	Cross Reference						- Appendix G2-FORECAST, Sch 21				- Appendix G2-FORECAST, Sch 29

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Account	Mid-year GPIS for Depreciation	Annual Salvage Rate %	2013 DEPRECIATION Provision (Cr.)	Adjust-ments	Removal Costs	Proceeds on Disposal	Ending 12/31/2012	Ending 12/31/2013
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ 18	$ 36
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	66	132
4	449-00 Local Storage Equipment (Tilbury)	26,075	0.37%	99	-	-	-	94	193
5	TOTAL MANUFACTURED	47,534		183	-	-	-	178	361
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	16,299	0.18%	27	-	-	-	27	54
9	463-00 Measuring Structures	5,501	0.18%	10	-	-	-	2	12
10	464-00 Other Structures & Improvements	6,042	0.14%	8	-	-	-	8	16
11	465-00 Mains	813,541	0.14%	1,175	-	(1,960)	-	968	183
12	466-00 Compressor Equipment	112,851	0.28%	333	-	-	-	314	647
13	467-00 Measuring & Regulating Equipment	30,184	0.18%	51	-	-	-	18	69
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	3	6
15	TOTAL TRANSMISSION	984,762		1,607	-	(1,960)	-	1,340	987
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	18,209	0.16%	27	-	-	-	27	54
19	473-00 Services	772,302	1.24%	8,982	-	(8,754)	-	(2,044)	(1,816)
20	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
21	474-00 House Regulators & Meter Installations	174,801	0.75%	1,188	-	(2,659)	-	4,039	2,568
22	477-00 Meters/Regulators Installations	29,288	0.75%	173	-	-	-	57	230
23	475-00 Mains	961,863	0.33%	3,107	-	(828)	-	1,798	4,077
24	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
25	476-00 Compressor Equipment	827	11.43%	165	-	-	-	165	330
26	477-00 Measuring & Regulating Equipment	92,345	0.52%	468	-	-	-	389	857
27	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
28	478-10 Meters	210,465	0.50%	1,031	-	-	-	14	1,045
29	TOTAL DISTRIBUTION	2,260,261		15,141	-	(12,241)	-	4,445	7,345
30									
31	**BIO GAS**								
32	475-20 Bio Gas Mains – Private Land	188	0.33%	1	-	-	-	-	1
33	478-30 Bio Gas Meters	227	0.50%	-	-	-	-	-	-
34	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
35	TOTAL BIO-GAS	437		2	-	-	-	1	3
36									
37	TOTALS	$ 3,292,994		$ 16,933	$ -	$ (14,201)	$ -	$ 5,964	$ 8,696
38									
39	Cross Reference	- Appendix G2-FORECAST, Sch 33							

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

Schedule 50

NEGATIVE SALVAGE CONTINUITY
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Account	GPIS for Depreciation	Annual Salvage Rate %	2014 DEPRECIATION Provision (Cr.)	Open Bal Transfers	Removal Costs	Proceeds on Disposal	Ending 12/31/2013	Ending 12/31/2014
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**MANUFACTURED GAS / LOCAL STORAGE**								
2	442-00 Structures & Improvements (Tilbury)	$ 4,960	0.36%	$ 18	$ -	$ -	$ -	$ 36	$ 54
3	443-00 Gas Holders - Storage (Tilbury)	16,499	0.40%	66	-	-	-	132	198
4	449-00 Local Storage Equipment (Tilbury)	27,136	0.37%	100	-	-	-	193	293
5	TOTAL MANUFACTURED	48,595		184	-	-	-	361	545
6									
7	**TRANSMISSION PLANT**								
8	462-00 Compressor Structures	16,299	0.18%	29	-	-	-	54	83
9	463-00 Measuring Structures	5,490	0.18%	10	-	-	-	12	22
10	464-00 Other Structures & Improvements	6,061	0.14%	8	-	-	-	16	24
11	465-00 Mains	827,569	0.14%	1,159	-	-	-	183	1,342
12	466-00 Compressor Equipment	113,890	0.28%	319	-	-	-	647	966
13	467-00 Measuring & Regulating Equipment	30,118	0.18%	54	-	-	-	69	123
14	468-00 Communication Structures & Equipment	346	0.96%	3	-	-	-	6	9
15	TOTAL TRANSMISSION	999,773		1,582	-	-	-	987	2,569
16									
17	**DISTRIBUTION PLANT**								
18	472-00 Structures & Improvements	18,198	0.16%	29	-	-	-	54	83
19	473-00 Services	786,258	1.24%	9,251	-	(9,532)	-	(1,816)	(2,097)
20	473-00 Services - LILO	-	0.00%	-	-	-	-	-	-
21	474-00 House Regulators & Meter Installations	174,659	0.75%	1,189	-	(2,894)	-	2,568	863
22	477-00 Meters/Regulators Installations	39,704	0.75%	298	-	-	-	230	528
23	475-00 Mains	976,452	0.33%	3,110	-	(901)	-	4,077	6,286
24	475-00 Mains - LILO	-	0.00%	-	-	-	-	-	-
25	476-00 Compressor Equipment	827	11.43%	95	-	-	-	330	425
26	477-00 Measuring & Regulating Equipment	96,095	0.52%	500	-	-	-	857	1,357
27	477-10 Measuring & Regulating Equipment - Byron Creek	163	0.00%	-	-	-	-	-	-
28	478-10 Meters	213,913	0.50%	1,019	-	-	-	1,045	2,064
29	TOTAL DISTRIBUTION	2,306,269		15,491	-	(13,327)	-	7,345	9,509
30									
31	**BIO GAS**								
32	475-20 Bio Gas Mains – Private Land	335	0.33%	1	-	-	-	1	2
33	478-30 Bio Gas Meters	447	0.50%	2	-	-	-	-	2
34	474-10 Bio Gas Reg & Meter Installations	22	0.00%	-	-	-	-	-	-
35	TOTAL BIO-GAS	804		3	-	-	-	3	6
36									
37	TOTALS	$ 3,355,441		$ 17,260	$ -	$ (13,327)	$ -	$ 8,696	$ 12,629
38									
39	Cross Reference	- Appendix G2-FORECAST, Sch 36							

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 51

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED Existing 2013 Rates	2013 PROJECTED 2013 Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6) (Column (5) - Column (3))	(7)
1	**Cash Working Capital**						
2	Cash Required for						
3	Operating Expenses	$ 9,202	$ 7,458	$ 8,528	$ 8,528	$ 1,070	- Appendix G2-FORECAST, Sch 53
4							
5							
6	Less - Funds Available:						
7							
8	Reserve for Bad Debts	(6,282)	(4,588)	(5,760)	(5,760)	(1,172)	
9							
10	Withholdings From Employees	(4,819)	(5,163)	(4,359)	(4,359)	804	
11							
12	Subtotal	(1,899)	(2,293)	(1,591)	(1,591)	702	- Appendix G2-FORECAST, Sch 28
13							
14	**Other Working Capital Items**						
15	Construction Advances	(439)	(620)	-	-	620	
16	Transmission Line Pack Gas	3,924	3,566	2,846	2,846	(720)	
17	Gas in Storage	97,294	97,242	78,766	78,766	(18,476)	
18	Inventory - Materials & Supplies	637	1,434	1,509	1,509	75	
19							
20	Subtotal	101,416	101,622	83,121	83,121	(18,501)	- Appendix G2-FORECAST, Sch 28
21							
22	Total	$ 99,517	$ 99,329	$ 81,530	$ 81,530	$ (17,799)	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

Schedule 52

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	2013 PROJECTED	2014 FORECAST Existing 2013 Rates	2014 FORECAST 2013 Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	$ 8,528	$ 9,726	$ 9,708	$ 1,180	- Appendix G2-FORECAST, Sch 53
4						
5						
6	Less - Funds Available:					
7						
8	Reserve for Bad Debts	(5,760)	(5,459)	(5,459)	301	
9						
10	Withholdings From Employees	(4,359)	(4,489)	(4,489)	(130)	
11						
12	Subtotal	(1,591)	(222)	(240)	1,351	- Appendix G2-FORECAST, Sch 29
13						
14	**Other Working Capital Items**					
15	Construction Advances	-	-	-	-	
16	Transmission Line Pack Gas	2,846	2,662	2,662	(184)	
17	Gas in Storage	78,766	74,841	74,841	(3,925)	
18	Inventory - Materials & Supplies	1,509	1,536	1,536	27	
19						
20	Subtotal	83,121	79,039	79,039	(4,082)	- Appendix G2-FORECAST, Sch 29
21						
22	Total	$ 81,530	$ 78,817	$ 78,799	$ (2,731)	

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

		2013			2014			
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CASH WORKING CAPITAL**							
2								
3	Revenue Lag Days	39.0			39.0			- Appendix G2-FORECAST, Sch 54
4	Expense Lead Days	35.8			35.4			- Appendix G2-FORECAST, Sch 55
5								
6	Net Lead/(Lag) Days	3.2	$ 972,689	$ 8,528	3.6	$ 986,151	$ 9,726	- Appendix G2-FORECAST, Sch 51
7								- Appendix G2-FORECAST, Sch 52
8								
9								
10	**CASH WORKING CAPITAL, REVISED RATES**							
11								
12	Revenue Lag Days	39.0			39.0			- Appendix G2-FORECAST, Sch 54
13	Expense Lead Days	35.8			35.4			- Appendix G2-FORECAST, Sch 55
14								
15	Net Lead/(Lag) Days	3.2	$ 972,689	$ 8,528	3.6	$ 984,294	$ 9,708	- Appendix G2-FORECAST, Sch 51
16								- Appendix G2-FORECAST, Sch 52
17								
18								
19	**CASH WORKING CAPITAL CHANGE**			$ -			$ (18)	
20								
21								
22								
23	Cash working capital = Col. 2 x Col. 3 / 365 days							

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 54

CASH WORKING CAPITAL
LAG TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

		2013			2014			
Line No.	Particulars	Revenue At 2013 Rates	Lag Days Service to Collection	Dollar Days	Revenue At 2013 Rates	Lag Days Service to Collection	Dollar Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**REVENUE**							
2								
3	Gas Sales and Transportation Service Revenue							
4	Residential and Commercial	$ 1,013,232	38.3	$ 38,850,744	$ 1,003,452	38.3	$ 38,476,516	- Appendix G2-FORECAST, Sch 10
5	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	76,551	45.1	3,451,304	78,560	45.1	3,542,123	
6	NGV Fuel - Stations	467	41.7	19,454	467	41.7	19,454	
7								
8	Rates 16, 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	56,374	42.9	2,416,294	62,894	42.6	2,679,862	
9								
10	Total Gas Sales	1,146,623	39.0	44,737,796	1,145,372	39.0	44,717,955	
11	Other Revenues							
12	Late Payment Charges	2,134	38.3	81,736	2,114	38.3	80,962	- Appendix G2-FORECAST, Sch 12 - 13
13	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Appendix G2-FORECAST, Sch 12 - 13
14	Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Appendix G2-FORECAST, Sch 12 - 13
15	Other Utility Income	132	35.4	4,670	649	43.2	28,048	- Appendix G2-FORECAST, Sch 12 - 13
16								
17								
18	Total Revenue	$ 1,151,590	39.0	$ 44,927,654	$ 1,150,850	39.0	$ 44,930,976	
19								
20								
21	**REVENUE, REVISED RATES**							
22								
23	Gas Sales and Transportation Service Revenue							
24	Residential and Commercial	$ 1,013,232	38.3	$ 38,850,744	$ 997,634	38.3	$ 38,253,401	- Appendix G2-FORECAST, Sch 10
25	Industrials & Others: Rates 4, 5, 7, 23, 25 and 27	76,551	45.1	3,451,304	77,796	45.1	3,507,624	
26	NGV Fuel - Stations	467	41.7	19,454	464	41.7	19,329	
27								
28	Rates 16, 22, Burrard, FEVI (Oth Rev), SCP (Oth Rev)	56,374	42.9	2,416,294	62,573	42.6	2,665,570	
29								
30	Total Gas Sales	1,146,623	39.0	44,737,796	1,138,466	39.0	44,445,924	
31	Other Revenues							
32	Late Payment Charges	2,134	38.3	81,736	2,114	38.3	80,962	- Appendix G2-FORECAST, Sch 12 - 13
33	Returned Cheque Charges	79	38.5	3,041	79	38.5	3,041	- Appendix G2-FORECAST, Sch 12 - 13
34	Connection Charges	2,622	38.3	100,411	2,636	38.3	100,970	- Appendix G2-FORECAST, Sch 12 - 13
35	Other Utility Income	132	35.4	4,670	649	43.2	28,048	- Appendix G2-FORECAST, Sch 12 - 13
36								
37								
38	Total Revenue	$ 1,151,590	39.0	$ 44,927,654	$ 1,143,944	39.0	$ 44,658,945	

CASH WORKING CAPITAL
LEAD TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars		2013 Amount	2013 Lead Days Expense to Payment	2013 Dollar Days	2014 Amount	2014 Lead Days Expense to Payment	2014 Dollar Days	Cross Reference
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**EXPENSES**								
2									
3	Operating And Maintenance								- Appendix G2-FORECAST, Sch 3
4	Expenses		$ 198,578	25.5	$ 5,063,739	$ 206,343	25.5	$ 5,261,747	- Appendix G2-FORECAST, Sch 4
5	Gas Purchases (excl Royalty Credits)		505,695	40.2	20,328,939	499,685	40.2	20,087,337	
6									
7	Taxes Other Than Income								- Appendix G2-FORECAST, Sch 18
8	Property Taxes		48,089	2.0	96,178	48,797	2.0	97,594	- Appendix G2-FORECAST, Sch 19
9	Franchise Fees		8,143	420.3	3,422,503	8,021	420.3	3,371,226	
10	Carbon Tax		169,756	29.1	4,939,904	171,305	29.1	4,984,978	
11	HST - Net	*	6,640	38.8	257,623			-	
12	PST Component of HST (REC)	*	(2,353)	33.8	(79,530)			-	
13	GST - Net	**	7,349	38.8	285,145	9,789	38.8	379,829	
14	PST - Net	**	3,284	37.1	121,854	4,110	37.1	152,487	
15	Income Tax		27,508	15.2	418,122	38,100	15.2	579,120	- Appendix G2-FORECAST, Sch 22
16									- Appendix G2-FORECAST, Sch 23
17	Total Expenses		$ 972,689	35.8	$ 34,854,477	$ 986,151	35.4	$ 34,914,318	
18									
19									
20	**EXPENSES, REVISED RATES**								
21									
22	Operating And Maintenance								- Appendix G2-FORECAST, Sch 3
23	Expenses		$ 198,578	25.5	$ 5,063,739	$ 206,343	25.5	$ 5,261,747	- Appendix G2-FORECAST, Sch 4
24	Gas Purchases (excl Royalty Credits)		505,695	40.2	20,328,939	499,685	40.2	20,087,337	
25									
26	Taxes Other Than Income								- Appendix G2-FORECAST, Sch 18
27	Property Taxes		48,089	2.0	96,178	48,797	2.0	97,594	- Appendix G2-FORECAST, Sch 19
28	Franchise Fees		8,143	420.3	3,422,503	7,971	420.3	3,350,211	
29	Carbon Tax		169,756	29.1	4,939,904	171,305	29.1	4,984,978	
30	HST - Net	*	6,640	38.8	257,623			-	
31	PST Component of HST (REC)	*	(2,353)	33.8	(79,530)			-	
31	GST - Net	**	7,349	38.8	285,145	9,730	38.8	377,526	
32	PST - Net	**	3,284	37.1	121,854	4,089	37.1	151,720	
33	Income Tax		27,508	15.2	418,122	36,373	15.2	552,870	- Appendix G2-FORECAST, Sch 22
34									- Appendix G2-FORECAST, Sch 23
35	Total Expenses		$ 972,689	35.8	$ 34,854,477	$ 984,294	35.4	$ 34,863,983	
36									
37	* January to March 2013 is computed at 25% of 2013 Approved cash outflows.								
38	** April to December 2013 is computed at 75% of 2013 Projected cash outflows.								

FORTISBC ENERGY INC. | June 10, 2013 | Appendix G2 FORECAST Schedule 56

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEARS ENDING DECEMBER 31, 2013 TO 2014
($000s)

Line No.	Particulars	2012 ACTUAL	2013 APPROVED	2013 PROJECTED	2014 FORECAST	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	Total DIT Liability- After Tax	(210,925)	(215,501)	(216,512)	(216,224)	
2						
3	Tax Gross Up	(70,308)	(71,834)	(72,171)	(72,075)	
4						
5	DIT Liability/Asset - End of Year	(281,233)	(287,335)	(288,683)	(288,298)	
6						
7	DIT Liability/Asset - Opening Balance	(282,624)	(277,382)	(281,233)	(288,683)	
8						
9	DIT Liability/Asset - Mid Year	(281,929)	(282,359)	(284,958)	(288,491)	
10						
11	Cross Reference			- Appendix G2-FORECAST, Sch 28		
12					- Appendix G2-FORECAST, Sch 29	
13						
14	Note: * Excludes Land, Software CIAC, and WIP.					

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 57

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2013
($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2013 RATES							
2	Long-Term Debt		$ 1,576,786	58.37%	6.87%	4.01%	$ 108,280	- Appendix G2-FORECAST, Sch 59
3	Unfunded Debt		44,139	1.63%	3.50%	0.06%	1,545	
4	Preference Shares			0.00%		0.00%	-	
5	Common Equity		1,080,617	40.00%	10.10%	4.04%	109,171	
6								
7			$ 2,701,542	100.00%		8.11%	$ 218,996	- Appendix G2-FORECAST, Sch 28
8								
9								
10								
11	2013 REVISED RATES - PROJECTED							
12	Long-Term Debt		$ 1,576,786	58.37%	6.87%	4.01%	$ 108,280	- Appendix G2-FORECAST, Sch 59
13	Unfunded Debt	$ 44,139						
14	Adjustment, Revised Rates	-	44,139	1.63%	3.50%	0.06%	1,545	
15	Preference Shares		-	0.00%	0.00%	0.00%	-	
16	Common Equity		1,080,617	40.00%	10.10%	4.04%	109,171	
17								- Appendix G2-FORECAST, Sch 3
18			$ 2,701,542	100.00%		8.11%	$ 218,996	- Appendix G2-FORECAST, Sch 28

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 58

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	-------- Capitalization --------	Amount	%	Average Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2014 AT 2013 RATES							
2	Long-Term Debt		$ 1,564,242	55.84%	6.84%	3.82%	$ 106,949	- Appendix G2-FORECAST, Sch 60
3	Unfunded Debt		158,564	5.66%	1.75%	0.10%	2,775	
4	Preference Shares			0.00%		0.00%	-	
5	Common Equity		1,078,505	38.50%	9.23%	3.55%	99,548	
6								
7			$ 2,801,311	100.00%		7.47%	$ 209,272	- Appendix G2-FORECAST, Sch 29
8								
9								
10								
11	2014 REVISED RATES							
12	Long-Term Debt		$ 1,564,242	55.84%	6.84%	3.82%	$ 106,949	- Appendix G2-FORECAST, Sch 60
13	Unfunded Debt	$ 158,564						
14	Adjustment, Revised Rates	(11)	158,553	5.66%	1.75%	0.10%	2,775	
15	Preference Shares		-	0.00%	0.00%	0.00%	-	
16	Common Equity		1,078,498	38.50%	8.75%	3.37%	94,369	
17								- Appendix G2-FORECAST, Sch 4
18			$ 2,801,293	100.00%		7.29%	$ 204,093	- Appendix G2-FORECAST, Sch 29

FORTISBC ENERGY INC. G-44-12 (May 1, 2012) Appendix G2

FORECAST

EMBEDDED COST OF LONG-TERM DEBT (per BCUC Approved RRA) Schedule 59

FOR THE YEAR ENDING DECEMBER 31, 2013 *** APPROVED ***

($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue		Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100	*	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	155,889	**	10.461%	158,117	16,541
3											
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710		7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085		6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337		5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216		5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697		6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588		5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,000	99,000		6.627%	100,000	6,627
11											
12	2011 Medium Term Debt Issue - Series 25	1-Oct-2011	1-Oct-2021	4.500%	100,000	1,000	99,000		4.626%	100,000	4,626
13											
14	LILO Obligations - Kelowna								6.445%	21,892	1,411
15	LILO Obligations - Nelson								7.872%	3,519	277
16	LILO Obligations - Vernon								9.153%	10,466	958
17	LILO Obligations - Prince George								8.067%	27,085	2,185
18	LILO Obligations - Creston								7.218%	2,577	186
19											
20	Vehicle Lease Obligation								5.685%	13,510	768
21											
22	Sub-Total									$ 1,582,121	$ 108,646
23	Less: Fort Nelson Division Portion of Long Term Debt									5,335	366
24	Total									$ 1,576,786	$ 108,280
25											
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).									Average Embedded Cost	6.87%
27	**Includes adjustment of $843 for BC Hydro Premium (Series B).										
28	Cross Reference									- Appendix G2-FORECAST, Sch 57	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

Schedule 60

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Series A Purchase Money Mortgage	3-Dec-1990	30-Sep-2015	11.800%	$ 58,943	$ 855	$ 74,100 *	12.054%	$ 74,955	$ 9,035
2	Series B Purchase Money Mortgage	30-Nov-1991	30-Nov-2016	10.300%	157,274	2,228	159,009 **	10.461%	161,237	16,867
3										
4	Medium Term Note - Series 11	21-Sep-1999	21-Sep-2029	6.950%	150,000	2,290	147,710	7.073%	150,000	10,610
5	2004 Long Term Debt Issue - Series 18	29-Apr-2004	1-May-2034	6.500%	150,000	1,915	148,085	6.598%	150,000	9,897
6	2005 Long Term Debt Issue - Series 19	25-Feb-2005	25-Feb-2035	5.900%	150,000	1,663	148,337	5.980%	150,000	8,970
7	2006 Long Term Debt Issue - Series 21	25-Sep-2006	25-Sep-2036	5.550%	120,000	784	119,216	5.595%	120,000	6,714
8	2007 Medium Term Debt Issue - Series 22	2-Oct-2007	2-Oct-2037	6.000%	250,000	2,303	247,697	6.067%	250,000	15,168
9	2008 Medium Term Debt Issue - Series 23	13-May-2008	13-May-2038	5.800%	250,000	2,412	247,588	5.869%	250,000	14,673
10	2009 Med.Term Debt Issue- Series 24	24-Feb-2009	24-Feb-2039	6.550%	100,000	1,234	98,766	6.645%	100,000	6,645
11	2011 Medium Term Debt Issue - Series 25	9-Dec-2011	9-Dec-2041	4.250%	100,000	1,410	98,590	4.334%	100,000	4,334
12										
13	LILO Obligations - Kelowna							6.469%	20,963	1,356
14	LILO Obligations - Nelson							7.983%	3,382	270
15	LILO Obligations - Vernon							9.276%	10,037	931
16	LILO Obligations - Prince George							8.182%	26,057	2,132
17	LILO Obligations - Creston							7.330%	2,483	182
18										
19	Vehicle Lease Obligation							2.281%	11,006	251
20										
21	Sub-Total								$ 1,580,120	$ 108,035
22	Less: Fort Nelson Division Portion of Long Term Debt								5,335	365
23	Less: NGT Class of Service Portion of Long Term Debt								10,543	721
24	Total								$ 1,564,242	$ 106,949
25										
26	*Includes adjustment of $16,012 for BC Hydro Premium (Series A).								Average Embedded Cost	6.84%
27	**Includes adjustment of $3,963 for BC Hydro Premium (Series B).									
28	Cross Reference								- Appendix G2-FORECAST, Sch 58	

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

Schedule 61

CALCULATION OF AMORTIZATION OF RSAM (RIDER 5)
FOR THE YEAR ENDING DECEMBER 31, 2014
($000s)

Particulars	2014 Volumes (TJ)	2014 Amortization ($000s)	2014 Amortization of RSAM Unit Rider ($/GJ)
(1)	(2)	(3)	(4)
RSAM (Rider 5) Calculation			
Schedule 1 - Residential	69,511.7		($0.118)
Schedule 2 - Small Commercial	24,246.8		($0.118)
Schedule 3 - Large Commercial	17,253.0		($0.118)
Schedule 23 - Large Commercial Transportation	8,721.3		($0.118)
	119,732.8	($14,156) [1]	

Note 1: RSAM Rider Change

In 2013, FortisBC Energy forecasts that there will be approximately $-5 million (net-of-tax) of RSAM additions. After offsetting the 2013 RSAM Rider recovery, the RSAM account including interest is now projected to be a credit balance of $-21.2 million on a net-of-tax basis by the end of 2013. The RSAM balance is to be amortized over two years. Accordingly, the net-of-tax RSAM balance to be amortized in 2014 is a credit of $-10.6 million. On a pre-tax basis, this amounts to $14.2 million or a refund to customers of $0.118/GJ in 2014, which is a $0.019 increase from the existing charge of ($0.099)/GJ.

2014 Net-Of-Tax Amortization = 1/2 of Projected December 31, 2013 RSAM Balance
= 1/2 * ($-20,919 RSAM + $-320 RSAM Interest)
= 1/2 * $-21,239
= $-10,620 Net-of-tax amortization

2014 Pre-Tax Amortization = Net-of-tax amortization / (1 - tax rate)
= $-10,620 / (1 - 25%)
= $-14,156 Pre-tax amortization

Summary of Rate Change

June 10, 2013

Appendix G2
FORECAST
Schedule 62

Line No.	Particulars	2014 ($ Millions)		2015 Incremental ($ Millions)		2015 Cumulative ($ Millions)		2016 Incremental ($ Millions)		2016 Cumulative ($ Millions)		2017 Incremental ($ Millions)		2017 Cumulative ($ Millions)		2018 Incremental ($ Millions)		2018 Cumulative ($ Millions)		Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
1	Volume/Revenue Related																			
2	Customer Growth and Use Rates	(10.8)		(4.8)		(15.6)		(4.8)		(20.4)		(4.7)		(25.2)		(3.1)		(28.3)		
3	Change in Other Revenue	1.2	(9.6)	(0.7)	(5.5)	0.5	(15.1)	(0.4)	(5.2)	0.1	(20.3)	(0.3)	(5.0)	(0.1)	(25.3)	(0.1)	(3.2)	(0.2)	(28.5)	
4																				
5	O&M Changes																			
6	Gross O&M Increases	3.9		5.8		9.8		6.7		16.4		6.9		23.3		8.6		31.9		
7	Less: Capitalized Overhead	(0.6)	3.4	(0.8)	5.0	(1.4)	8.4	(0.9)	5.7	(2.3)	14.1	(1.0)	5.9	(3.3)	20.0	(1.2)	7.4	(4.5)	27.4	
8																				
9	Depreciation Expense																			
10	Change in Depreciation Rates	(0.1)		1.8		1.7		1.3		3.0		(0.2)		2.7		0.1		2.9		
11	Tax Expense Impact of Depreciation Changes	0.3		2.1		2.4		2.0		4.4		1.3		5.7		1.6		7.3		
12	Depreciation from Net Additions	1.0	1.2	4.5	8.4	5.5	9.7	4.7	8.0	10.3	17.7	4.2	5.3	14.5	23.0	4.7	6.4	19.2	29.4	
13																				
14	Amortization Expense																			
15	CIAC	0.2		0.3		0.5		0.0		0.5		0.2		0.7		0.2		0.9		
16	Deferral Accounts	4.6	4.8	1.0	1.3	5.7	6.2	3.7	3.8	9.4	9.9	1.8	2.0	11.2	11.9	1.8	2.0	13.0	13.9	
17																				
18	Other																			
19	Property and Other Taxes	(2.4)		0.5		(1.9)		1.3		(0.6)		1.0		0.4		1.1		1.5		
20	Other (NSP Provision)	-		-		-		-		-		-		-		-		-		
21	Income Tax Rate Change	-		-		-		-		-		-		-		-		-		
22	Other Income Tax Changes	8.0		(0.6)		7.5		(0.0)		7.4		0.6		8.0		0.7		8.7		
23	Financing Rate Changes	(11.3)		(0.5)		(11.8)		(2.9)		(14.7)		(8.1)		(22.8)		(0.8)		(23.5)		
24	Financing Changes	(2.1)		1.4		(0.8)		1.0		0.3		4.2		4.5		3.9		8.4		
25	Rate Base Growth	1.1	(6.7)	2.0	2.9	3.2	(3.9)	1.7	1.0	4.8	(2.8)	1.1	(1.1)	6.0	(4.0)	0.9	5.8	6.9	1.8	
26																				
27	**Revenue Deficiency (Surplus)**		**(6.9)**				**5.3**				**18.6**				**25.6**				**44.1**	
28			- Appendix G2-FORECAST, Sch 1																	
29			- Appendix G2-FORECAST, Sch 2				- Appendix G2-FORECAST, Sch 63				- Appendix G2-FORECAST, Sch 68				- Appendix G2-FORECAST, Sch 73				- Appendix G2-FORECAST, Sch 78	

FORTISBC ENERGY INC.

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Non-Bypass Sales	2015 Non-Bypass Transportation	2015 Bypass and Special Rates	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,127,236	$ 1,031,709	$ 86,853	$ 11,524	$ 1,130,086	$ 2,850	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,138	-	-	18,148	18,148	10	
8								
9	Total Revenue	1,145,374	1,031,709	86,853	29,672	1,148,234	2,860	
10								
11	Less - Cost of Gas	(499,685)	(497,198)	(253)	(249)	(497,700)	1,985	
12								
13	Gross Margin	$ 645,689	$ 534,511	$ 86,600	$ 29,423	$ 650,534	$ 4,845	
14								
15	Revenue Deficiency (Surplus)	$ (6,906)	$ 4,521	$ 733	$ -	**$ 5,254**	$ 12,160	- Appendix G2-FORECAST, Sch 62
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	-1.07%	0.85%	0.85%	0.00%	0.81%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	-0.60%	0.44%	0.84%	0.00%	0.46%		
20								

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 64

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Revised Revenue	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	114,985	115,590	-	115,590	605	
3	Transportation	98,582	99,707	-	99,707	1,125	
4		213,567	215,297	-	215,297	1,730	
5							
6	Average Rate per GJ						
7	Sales	$8.912	$8.926	$0.000	$8.965	$0.053	
8	Transportation	$0.969	$0.987	$0.000	$0.994	$0.025	
9	Average	$5.246	$5.249	$0.000	$5.273	$0.027	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,030,748	$ 1,031,709	$ -	$ 1,031,709	$ 961	
13	- Increase / (Decrease)	(5,956)	-	4,521	4,521	10,477	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	96,488	98,377	-	98,377	1,889	
16	- Increase / (Decrease)	(950)		733	733	1,683	
17							
18	**Total Revenue**	1,120,330	1,130,086	5,254	1,135,340	15,010	
19							
20	Cost of Gas Sold (Including Gas Lost)	499,685	497,700	-	497,700	(1,985)	
21							
22	**Gross Margin**	620,645	632,386	5,254	637,640	16,995	
23							
24	Operation and Maintenance	206,343	211,354	-	211,354	5,011	
25	Property and Sundry Taxes	48,797	49,335	-	49,335	538	
26	Depreciation and Amortization	148,655	156,320	-	156,320	7,665	
27	Other Operating Revenue	(23,616)	(24,289)	-	(24,289)	(673)	
28	Sub-total	380,179	392,720	-	392,720	12,541	
29	Utility Income Before Income Taxes	240,466	239,666	5,254	244,920	4,454	
30							
31	Income Taxes	36,373	36,611	1,312	37,923	1,550	
32							
33	**EARNED RETURN**	$ 204,093	$ 203,055	$ 3,942	$ 206,997	$ 2,904	- Appendix G2-FORECAST, Sch 67
34							
35							
36	**UTILITY RATE BASE**	$ 2,801,293	$ 2,861,472	$ 286	$ 2,861,758	$ 60,465	- Appendix G2-FORECAST, Sch 66
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.29%	7.10%		7.23%	-0.05%	- Appendix G2-FORECAST, Sch 67

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 65

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Revised Revenue	2015 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 204,093	$ 203,055	$ 3,942	$ 206,997	$ 2,904	- Appendix G2-FORECAST, Sch 64
3	Deduct - Interest on Debt	(109,724)	(110,588)	(4)	(110,592)	(868)	- Appendix G2-FORECAST, Sch 67
4	Add (Deduct) - Permanent & Timing Differences	14,751	17,365	-	17,365	2,614	
5	Accounting Income After Tax	$ 109,120	109,832	3,938	$ 113,770	4,650	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 145,493	$ 146,443	$ 5,251	$ 151,693	$ 6,200	
11							
12							
13	Income Tax - Current	$ 36,373	$ 36,611	$ 1,313	$ 37,923	$ 1,550	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 36,373	$ 36,611	$ 1,313	$ 37,923	$ 1,550	- Appendix G2-FORECAST, Sch 64
17							

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 66

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	2014 FORECAST	2015 Existing 2013 Rates	2015 Adjustments	2015 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 3,870,158	$ 4,013,029	$ -	$ 4,013,029	$ 142,871	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,013,029	4,160,688	-	4,160,688	147,659	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,105,308)	$ (1,206,131)	$ -	$ (1,206,131)	$ (100,823)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,206,131)	(1,317,362)	-	(1,317,362)	(111,231)	
8							
9	CIAC, Beginning	$ (194,421)	$ (196,475)	$ -	$ (196,475)	$ (2,054)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(196,475)	(200,580)	-	(200,580)	(4,105)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 57,362	$ 59,914	$ -	$ 59,914	$ 2,552	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	59,914	64,212	-	64,212	4,298	
16							
17	Net Plant in Service, Mid-Year	$ 2,649,064	$ 2,688,648	$ -	$ 2,688,648	$ 39,584	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	48,293	66,754	-	66,754	18,461	
22	Cash Working Capital	(240)	63	286	349	589	
23	Other Working Capital	79,039	80,704	-	80,704	1,665	
24	Deferred Income Taxes Regulatory Asset	288,491	287,865	-	287,865	(626)	
25	Deferred Income Taxes Regulatory Liability	(288,491)	(287,865)	-	(287,865)	626	
26	LILO Benefit	(983)	(817)	-	(817)	166	
27	**Utility Rate Base**	$ 2,801,293	$ 2,861,472	$ 286	$ 2,861,758	$ 60,465	- Appendix G2-FORECAST, Sch 67

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 67

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2015
($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2015 AT 2013 RATES							
2	Long-Term Debt		$ 1,559,413	54.50%	6.77%	3.69%		
3	Unfunded Debt		200,392	7.00%	2.50%	0.18%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,101,667	38.50%	8.39%	3.23%		
6								
7			$ 2,861,472	100.00%		7.10%		- Appendix G2-FORECAST, Sch 66
8								
9	2015 REVISED RATES							
10	Long-Term Debt		$ 1,559,413	54.49%	6.77%	3.69%	$ 105,578	
11	Unfunded Debt	$ 200,392						
12	Adjustment, Revised Rates	176	200,568	7.01%	2.50%	0.18%	5,014	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,101,777	38.50%	8.75%	3.37%	96,405	
15								- Appendix G2-FORECAST, Sch 64
16			$ 2,861,758	100.00%		7.23%	$ 206,997	- Appendix G2-FORECAST, Sch 66
17								
18	2014 REVISED RATES							
19	Long-Term Debt		$ 1,564,242	55.84%	6.84%	3.82%	$ 106,949	
20	Unfunded Debt	$ 158,564						
21	Adjustment, Revised Rates	(11)	158,553	5.66%	1.75%	0.10%	2,775	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,078,498	38.50%	8.75%	3.37%	94,369	
24								
25			$ 2,801,293	100.00%		7.29%	$ 204,093	
26								
27	CHANGE FROM 2014 REVISED RATES							
28	Long-Term Debt		$ (4,829)	-1.35%	-0.07%	-0.13%	$ (1,371)	
29	Unfunded Debt	$ 41,828						
30	Adjustment, Revised Rates	187	42,015	1.35%	0.75%	0.08%	2,239	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		23,279	0.00%	0.00%	0.00%	2,036	
33								
34			$ 60,465	0.00%		-0.05%	$ 2,904	

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 68

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Non-Bypass Sales	2016 Non-Bypass Transportation	2016 Bypass and Special Rates	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,130,086	$ 1,037,604	$ 88,775	$ 11,524	$ 1,137,903	$ 7,817	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,148	-	-	18,159	18,159	11	
8								
9	Total Revenue	1,148,234	1,037,604	88,775	29,683	1,156,062	7,828	
10								
11	Less - Cost of Gas	(497,700)	(500,169)	(255)	(252)	(500,676)	(2,976)	
12								
13	Gross Margin	$ 650,534	$ 537,435	$ 88,520	$ 29,431	$ 655,386	$ 4,852	
14								
15	Revenue Deficiency (Surplus)	$ 5,254	$ 15,959	$ 2,628	$ -	**$ 18,587**	$ 13,333	- Appendix G2-FORECAST, Sch 62
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	0.81%	2.97%	2.97%	0.00%	2.84%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	0.46%	1.54%	2.96%	0.00%	1.61%		
20								

FORTISBC ENERGY INC. June 10, 2013 Appendix G2

FORECAST

Schedule 69

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	115,590	116,182	-	116,182	592	
3	Transportation	99,707	100,620	-	100,620	913	
4		215,297	216,802	-	216,802	1,505	
5							
6	Average Rate per GJ						
7	Sales	$8.965	$8.931	$0.000	$9.068	$0.103	
8	Transportation	$0.994	$0.997	$0.000	$1.023	$0.029	
9	Average	$5.273	$5.249	$0.000	$5.334	$0.061	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,031,709	$ 1,037,604	$ -	$ 1,037,604	$ 5,895	
13	- Increase / (Decrease)	4,521	-	15,959	15,959	11,438	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	98,377	100,299	-	100,299	1,922	
16	- Increase / (Decrease)	733		2,628	2,628	1,895	
17							
18	**Total Revenue**	1,135,340	1,137,903	18,587	1,156,490	21,150	
19							
20	Cost of Gas Sold (Including Gas Lost)	497,700	500,676	-	500,676	2,976	
21							
22	**Gross Margin**	637,640	637,227	18,587	655,814	18,174	
23							
24	Operation and Maintenance	211,354	217,101	-	217,101	5,747	
25	Property and Sundry Taxes	49,335	50,614	-	50,614	1,279	
26	Depreciation and Amortization	156,320	166,073	-	166,073	9,753	
27	Other Operating Revenue	(24,289)	(24,642)	-	(24,642)	(353)	
28	Sub-total	392,720	409,146	-	409,146	16,426	
29	Utility Income Before Income Taxes	244,920	228,081	18,587	246,668	1,748	
30							
31	Income Taxes	37,923	35,228	4,646	39,874	1,951	
32							
33	**EARNED RETURN**	$ 206,997	$ 192,853	$ 13,941	$ 206,794	$ (203)	- Appendix G2-FORECAST, Sch 72
34							
35							
36	**UTILITY RATE BASE**	$ 2,861,758	$ 2,911,562	$ 52	$ 2,911,614	$ 49,856	- Appendix G2-FORECAST, Sch 71
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.23%	6.62%		7.10%	-0.13%	- Appendix G2-FORECAST, Sch 72

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 70

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	2015 FORECAST	2016 Existing 2013 Rates	2016 Revised Revenue	2016 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 206,997	$ 192,853	$ 13,941	$ 206,794	$ (203)	- Appendix G2-FORECAST, Sch 69
3	Deduct - Interest on Debt	(110,592)	(108,708)	(1)	(108,709)	1,883	- Appendix G2-FORECAST, Sch 72
4	Add (Deduct) - Permanent & Timing Differences	17,365	21,538	-	21,538	4,173	
5	Accounting Income After Tax	$ 113,770	105,683	13,940	$ 119,623	5,853	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 151,693	$ 140,911	$ 18,587	$ 159,497	$ 7,804	
11							
12							
13	Income Tax - Current	$ 37,923	$ 35,228	$ 4,647	$ 39,874	$ 1,951	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 37,923	$ 35,228	$ 4,647	$ 39,874	$ 1,951	- Appendix G2-FORECAST, Sch 69
17							

FORTISBC ENERGY INC.

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Appendix G2
FORECAST
Schedule 71

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

			2016				
Line No.	Particulars	2015 FORECAST	Existing 2013 Rates	Adjustments	Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,013,029	$ 4,160,688	$ -	$ 4,160,688	$ 147,659	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,160,688	4,291,272	-	4,291,272	130,584	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,206,131)	$ (1,317,362)	$ -	$ (1,317,362)	$ (111,231)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,317,362)	(1,417,468)	-	(1,417,468)	(100,106)	
8							
9	CIAC, Beginning	$ (196,475)	$ (200,580)	$ -	$ (200,580)	$ (4,105)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(200,580)	(203,865)	-	(203,865)	(3,285)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 59,914	$ 64,212	$ -	$ 64,212	$ 4,298	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	64,212	67,641	-	67,641	3,429	
16							
17	Net Plant in Service, Mid-Year	$ 2,688,648	$ 2,722,269	$ -	$ 2,722,269	$ 33,622	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	66,754	78,679	-	78,679	11,925	
22	Cash Working Capital	349	486	52	538	189	
23	Other Working Capital	80,704	84,659	-	84,659	3,955	
24	Deferred Income Taxes Regulatory Asset	287,865	286,758	-	286,758	(1,107)	
25	Deferred Income Taxes Regulatory Liability	(287,865)	(286,758)	-	(286,758)	1,107	
26	LILO Benefit	(817)	(651)	-	(651)	166	
27	**Utility Rate Base**	$ 2,861,758	$ 2,911,562	$ 52	$ 2,911,614	$ 49,857	- Appendix G2-FORECAST, Sch 72

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2016
($000s)

Line No.	Particulars	-------- Capitalization -------- Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2016 AT 2013 RATES							
2	Long-Term Debt		$ 1,556,201	53.45%	6.50%	3.47%		
3	Unfunded Debt		234,410	8.05%	3.25%	0.26%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,120,951	38.50%	7.51%	2.89%		
6								
7			$ 2,911,562	100.00%		6.62%		- Appendix G2-FORECAST, Sch 71
8								
9	2016 REVISED RATES							
10	Long-Term Debt		$ 1,556,201	53.45%	6.50%	3.47%	$ 101,090	
11	Unfunded Debt	$ 234,410						
12	Adjustment, Revised Rates	32	234,442	8.05%	3.25%	0.26%	7,619	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,120,971	38.50%	8.75%	3.37%	98,085	
15								- Appendix G2-FORECAST, Sch 69
16			$ 2,911,614	100.00%		7.10%	$ 206,794	- Appendix G2-FORECAST, Sch 71
17								
18	2015 REVISED RATES							
19	Long-Term Debt		$ 1,559,413	54.49%	6.77%	3.69%	$ 105,578	
20	Unfunded Debt	$ 200,392						
21	Adjustment, Revised Rates	176	200,568	7.01%	2.50%	0.18%	5,014	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,101,777	38.50%	8.75%	3.37%	96,405	
24								
25			$ 2,861,758	100.00%		7.23%	$ 206,997	- Appendix G2-FORECAST, Sch 67
26								
27	CHANGE FROM 2015 REVISED RATES							
28	Long-Term Debt		$ (3,212)	-1.04%	-0.27%	-0.22%	$ (4,488)	
29	Unfunded Debt	$ 34,018						
30	Adjustment, Revised Rates	(144)	33,874	1.04%	0.75%	0.08%	2,605	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		19,194	0.00%	0.00%	0.00%	1,680	
33								
34			$ 49,856	0.00%		-0.14%	$ (203)	

FORTISBC ENERGY INC.

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Appendix G2
FORECAST
Schedule 73

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Non-Bypass Sales	2017 Non-Bypass Transportation	2017 Bypass and Special Rates	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,137,903	$ 1,043,557	$ 90,727	$ 11,525	$ 1,145,809	$ 7,906	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,159	-	-	18,160	18,160	1	
8								
9	Total Revenue	1,156,062	1,043,557	90,727	29,685	1,163,969	7,907	
10								
11	Less - Cost of Gas	(500,676)	(503,353)	(259)	(253)	(503,865)	(3,189)	
12								
13	Gross Margin	$ 655,386	$ 540,204	$ 90,468	$ 29,432	$ 660,104	$ 4,718	
14								
15	Revenue Deficiency (Surplus)	$ 18,587	$ 21,958	$ 3,677	$ -	**$ 25,635**	$ 7,048	- Appendix G2-FORECAST, Sch 62
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	2.84%	4.06%	4.06%	0.00%	3.88%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	1.61%	2.10%	4.05%	0.00%	2.20%		
20								

FORTISBC ENERGY INC. June 10, 2013 Appendix G2
FORECAST
Schedule 74

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Revised Revenue	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	116,182	116,735	-	116,735	553	
3	Transportation	100,620	101,629	-	101,629	1,009	
4		216,802	218,364	-	218,364	1,562	
5							
6	Average Rate per GJ						
7	Sales	$9.068	$8.940	$0.000	$9.128	$0.060	
8	Transportation	$1.023	$1.006	$0.000	$1.042	$0.019	
9	Average	$5.334	$5.247	$0.000	$5.365	$0.031	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,037,604	$ 1,043,557	$ -	$ 1,043,557	$ 5,953	
13	- Increase / (Decrease)	15,959	-	21,958	21,958	5,999	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	100,299	102,253	-	102,253	1,954	
16	- Increase / (Decrease)	2,628		3,677	3,677	1,049	
17							
18	**Total Revenue**	1,156,490	1,145,810	25,635	1,171,445	14,955	
19							
20	Cost of Gas Sold (Including Gas Lost)	500,676	503,865	-	503,865	3,189	
21							
22	**Gross Margin**	655,814	641,945	25,635	667,580	11,766	
23							
24	Operation and Maintenance	217,101	223,010	-	223,010	5,909	
25	Property and Sundry Taxes	50,614	51,598	-	51,598	984	
26	Depreciation and Amortization	166,073	172,016	-	172,016	5,943	
27	Other Operating Revenue	(24,642)	(24,916)	-	(24,916)	(274)	
28	Sub-total	409,146	421,708	-	421,708	12,562	
29	Utility Income Before Income Taxes	246,668	220,237	25,635	245,872	(796)	
30							
31	Income Taxes	39,874	35,410	6,408	41,818	1,944	
32							
33	**EARNED RETURN**	$ 206,794	$ 184,827	$ 19,227	$ 204,054	$ (2,740)	- Appendix G2-FORECAST, Sch 77
34							
35							
36	**UTILITY RATE BASE**	$ 2,911,614	$ 2,945,002	$ 73	$ 2,945,075	$ 33,461	- Appendix G2-FORECAST, Sch 76
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	7.10%	6.28%		6.93%	-0.17%	- Appendix G2-FORECAST, Sch 77

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INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Revised Revenue	2017 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 206,794	$ 184,827	$ 19,227	$ 204,054	$ (2,740)	- Appendix G2-FORECAST, Sch 74
3	Deduct - Interest on Debt	(108,709)	(104,840)	(2)	(104,842)	3,867	- Appendix G2-FORECAST, Sch 77
4	Add (Deduct) - Permanent & Timing Differences	21,538	26,243	-	26,243	4,705	
5	Accounting Income After Tax	$ 119,623	106,230	19,225	$ 125,455	5,832	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 159,497	$ 141,640	$ 25,633	$ 167,273	$ 7,776	
11							
12							
13	Income Tax - Current	$ 39,874	$ 35,410	$ 6,408	$ 41,818	$ 1,944	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 39,874	$ 35,410	$ 6,408	$ 41,818	$ 1,944	- Appendix G2-FORECAST, Sch 74
17							

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Schedule 76

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	2016 FORECAST	2017 Existing 2013 Rates	2017 Adjustments	2017 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,160,688	$ 4,291,272	$ -	$ 4,291,272	$ 130,584	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,291,272	4,437,288	-	4,437,288	146,016	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,317,362)	$ (1,417,468)	$ -	$ (1,417,468)	$ (100,106)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,417,468)	(1,531,862)	-	(1,531,862)	(114,394)	
8							
9	CIAC, Beginning	$ (200,580)	$ (203,865)	$ -	$ (203,865)	$ (3,285)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(203,865)	(206,768)	-	(206,768)	(2,903)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 64,212	$ 67,641	$ -	$ 67,641	$ 3,429	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	67,641	70,538	-	70,538	2,897	
16							
17	Net Plant in Service, Mid-Year	$ 2,722,269	$ 2,753,388	$ -	$ 2,753,388	$ 31,119	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	78,679	74,744	-	74,744	(3,935)	
22	Cash Working Capital	538	724	73	797	259	
23	Other Working Capital	84,659	90,511	-	90,511	5,852	
24	Deferred Income Taxes Regulatory Asset	286,758	285,204	-	285,204	(1,554)	
25	Deferred Income Taxes Regulatory Liability	(286,758)	(285,204)	-	(285,204)	1,554	
26	LILO Benefit	(651)	(485)	-	(485)	166	
27	**Utility Rate Base**	$ 2,911,614	$ 2,945,002	$ 73	$ 2,945,075	$ 33,461	- Appendix G2-FORECAST, Sch 77

FORTISBC ENERGY INC.

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Appendix G2
FORECAST
Schedule 77

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2017
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2017 AT 2013 RATES							
2	Long-Term Debt		$ 1,654,026	56.16%	5.98%	3.36%		
3	Unfunded Debt		157,150	5.34%	3.75%	0.20%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,133,826	38.50%	7.05%	2.72%		
6								
7			$ 2,945,002	100.00%		6.28%		- Appendix G2-FORECAST, Sch 76
8								
9	2017 REVISED RATES							
10	Long-Term Debt		$ 1,654,026	56.16%	5.98%	3.36%	$ 98,947	
11	Unfunded Debt	$ 157,150						
12	Adjustment, Revised Rates	45	157,195	5.34%	3.75%	0.20%	5,895	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,133,854	38.50%	8.75%	3.37%	99,212	
15								- Appendix G2-FORECAST, Sch 74
16			$ 2,945,075	100.00%		6.93%	$ 204,054	- Appendix G2-FORECAST, Sch 76
17								
18	2016 REVISED RATES							
19	Long-Term Debt		$ 1,556,201	53.45%	6.50%	3.47%	$ 101,090	
20	Unfunded Debt	$ 234,410						
21	Adjustment, Revised Rates	32	234,442	8.05%	3.25%	0.26%	7,619	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,120,971	38.50%	8.75%	3.37%	98,085	
24								
25			$ 2,911,614	100.00%		7.10%	$ 206,794	- Appendix G2-FORECAST, Sch 72
26								
27	CHANGE FROM 2016 REVISED RATES							
28	Long-Term Debt		$ 97,825	2.71%	-0.52%	-0.11%	$ (2,143)	
29	Unfunded Debt	$ (77,260)						
30	Adjustment, Revised Rates	13	(77,247)	-2.71%	0.50%	-0.06%	(1,724)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		12,883	0.00%	0.00%	0.00%	1,127	
33								
34			$ 33,461	0.00%		-0.17%	$ (2,740)	

FORTISBC ENERGY INC.

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Appendix G2
FORECAST
Schedule 78

SUMMARY OF RATE CHANGE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Non-Bypass Sales	2018 Non-Bypass Transportation	2018 Bypass and Special Rates	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE CHANGE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$ 1,145,809	$ 1,045,927	$ 92,694	$ 11,525	$ 1,150,146	$ 4,337	
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue	18,160	-	-	18,159	18,159	(1)	
8								
9	Total Revenue	1,163,969	1,045,927	92,694	29,684	1,168,305	4,336	
10								
11	Less - Cost of Gas	(503,865)	(504,563)	(262)	(255)	(505,080)	(1,215)	
12								
13	Gross Margin	$ 660,104	$ 541,364	$ 92,432	$ 29,429	$ 663,225	$ 3,121	
14								
15	Revenue Deficiency (Surplus)	$ 25,635	$ 37,685	$ 6,434	$ -	**$ 44,119**	$ 18,484	- Appendix G2-FORECAST, Sch 62
16								
17	Revenue Deficiency (Surplus) as a % of Gross Margin	3.88%	6.96%	6.96%	0.00%	6.65%		
18								
19	Revenue Deficiency (Surplus) as a % of Total Revenue	2.20%	3.60%	6.94%	0.00%	3.78%		
20								

FORTISBC ENERGY INC. June 10, 2013 Appendix G2 FORECAST Schedule 79

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	116,735	116,901	-	116,901	166	
3	Transportation	101,629	102,632	-	102,632	1,003	
4		218,364	219,533	-	219,533	1,169	
5							
6	Average Rate per GJ						
7	Sales	$9.128	$8.947	$0.000	$9.269	$0.141	
8	Transportation	$1.042	$1.015	$0.000	$1.078	$0.036	
9	Average	$5.365	$5.239	$0.000	$5.440	$0.075	
10							
11	UTILITY REVENUE						
12	Sales - Existing Rates	$ 1,043,557	$ 1,045,927	$ -	$ 1,045,927	$ 2,370	
13	- Increase / (Decrease)	21,958	-	37,684	37,684	15,726	
14	RSAM Revenue					-	
15	Transportation - Existing Rates	102,253	104,220	-	104,220	1,967	
16	- Increase / (Decrease)	3,677		6,435	6,435	2,758	
17							
18	**Total Revenue**	1,171,445	1,150,147	44,119	1,194,266	22,821	
19							
20	Cost of Gas Sold (Including Gas Lost)	503,865	505,080	-	505,080	1,215	
21							
22	**Gross Margin**	667,580	645,067	44,119	689,186	21,606	
23							
24	Operation and Maintenance	223,010	230,400	-	230,400	7,390	
25	Property and Sundry Taxes	51,598	52,691	-	52,691	1,093	
26	Depreciation and Amortization	172,016	178,868	-	178,868	6,852	
27	Other Operating Revenue	(24,916)	(24,967)	-	(24,967)	(51)	
28	Sub-total	421,708	436,992	-	436,992	15,284	
29	Utility Income Before Income Taxes	245,872	208,075	44,119	252,194	6,322	
30							
31	Income Taxes	41,818	33,065	11,026	44,091	2,273	
32							
33	**EARNED RETURN**	$ 204,054	$ 175,010	$ 33,093	$ 208,103	$ 4,049	- Appendix G2-FORECAST, Sch 82
34							
35							
36	**UTILITY RATE BASE**	$ 2,945,075	$ 2,971,702	$ 430	$ 2,972,132	$ 27,057	- Appendix G2-FORECAST, Sch 81
37							
38	**RATE OF RETURN ON UTILITY RATE BASE**	6.93%	5.89%		7.00%	0.07%	- Appendix G2-FORECAST, Sch 82

FORTISBC ENERGY INC.

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Appendix G2
FORECAST
Schedule 80

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Revised Revenue	2018 Total	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	EARNED RETURN	$ 204,054	$ 175,010	$ 33,093	$ 208,103	$ 4,049	- Appendix G2-FORECAST, Sch 79
3	Deduct - Interest on Debt	(104,842)	(107,966)	(13)	(107,979)	(3,137)	- Appendix G2-FORECAST, Sch 82
4	Add (Deduct) - Permanent & Timing Differences	26,243	32,150	-	32,150	5,907	
5	Accounting Income After Tax	$ 125,455	99,194	33,080	$ 132,274	6,819	
6							
7	Current Income Tax Rate	25.00%	25.00%	25.00%	25.00%	0.00%	
8	1 - Current Income Tax Rate	75.00%	75.00%	75.00%	75.00%	0.00%	
9							
10	Taxable Income	$ 167,273	$ 132,259	$ 44,107	$ 176,365	$ 9,092	
11							
12							
13	Income Tax - Current	$ 41,818	$ 33,065	$ 11,027	$ 44,091	$ 2,273	
14	Previous Year Adjustment	-	-	-	-	-	
15							
16	**Total Income Tax**	$ 41,818	$ 33,065	$ 11,027	$ 44,091	$ 2,273	- Appendix G2-FORECAST, Sch 79
17							

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UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	2017 FORECAST	2018 Existing 2013 Rates	2018 Adjustments	2018 Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service, Beginning	$ 4,291,272	$ 4,437,288	$ -	$ 4,437,288	$ 146,016	
2	Opening Balance Adjustment		-	-	-	-	
3	Gas Plant in Service, Ending	4,437,288	4,593,152	-	4,593,152	155,864	
4							
5	Accumulated Depreciation Beginning - Plant	$ (1,417,468)	$ (1,531,862)	$ -	$ (1,531,862)	$ (114,394)	
6	Opening Balance Adjustment		-	-	-	-	
7	Accumulated Depreciation Ending - Plant	(1,531,862)	(1,658,137)	-	(1,658,137)	(126,275)	
8							
9	CIAC, Beginning	$ (203,865)	$ (206,768)	$ -	$ (206,768)	$ (2,903)	
10	Opening Balance Adjustment		-	-	-	-	
11	CIAC, Ending	(206,768)	(212,973)	-	(212,973)	(6,205)	
12							
13	Accumulated Amortization Beginning - CIAC	$ 67,641	$ 70,538	$ -	$ 70,538	$ 2,897	
14	Opening Balance Adjustment		-	-	-	-	
15	Accumulated Amortization Ending - CIAC	70,538	76,539	-	76,539	6,001	
16							
17	Net Plant in Service, Mid-Year	$ 2,753,388	$ 2,783,889	$ -	$ 2,783,889	$ 30,501	
18							
19	Adjustment to 13-Month Average	-	-	-	-	-	
20	Work in Progress, No AFUDC	26,120	26,120	-	26,120	-	
21	Unamortized Deferred Charges	74,744	64,706	-	64,706	(10,038)	
22	Cash Working Capital	797	625	430	1,055	258	
23	Other Working Capital	90,511	96,690	-	96,690	6,179	
24	Deferred Income Taxes Regulatory Asset	285,204	282,818	-	282,818	(2,386)	
25	Deferred Income Taxes Regulatory Liability	(285,204)	(282,818)	-	(282,818)	2,386	
26	LILO Benefit	(485)	(328)	-	(328)	157	
27	**Utility Rate Base**	$ 2,945,075	$ 2,971,702	$ 430	$ 2,972,132	$ 27,057	- Appendix G2-FORECAST, Sch 82

FORTISBC ENERGY INC.

June 10, 2013

Appendix G2
FORECAST
Schedule 82

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2018
($000s)

Line No.	Particulars	Capitalization Amount		%	Embedded Cost	Cost Component	Earned Return	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2018 AT 2013 RATES							
2	Long-Term Debt		$ 1,752,796	58.98%	5.96%	3.52%		
3	Unfunded Debt		74,801	2.52%	4.75%	0.12%		
4	Preference Shares		-	0.00%	0.00%	0.00%		
5	Common Equity		1,144,105	38.50%	5.86%	2.25%		
6								
7			$ 2,971,702	100.00%		5.89%		- Appendix G2-FORECAST, Sch 81
8								
9	2018 REVISED RATES							
10	Long-Term Debt		$ 1,752,796	58.97%	5.96%	3.51%	$ 104,413	
11	Unfunded Debt	$ 74,801						
12	Adjustment, Revised Rates	264	75,065	2.53%	4.75%	0.12%	3,566	
13	Preference Shares		-	0.00%	0.00%	0.00%	-	
14	Common Equity		1,144,271	38.50%	8.75%	3.37%	100,124	
15								- Appendix G2-FORECAST, Sch 79
16			$ 2,972,132	100.00%		7.00%	$ 208,103	- Appendix G2-FORECAST, Sch 81
17								
18	2017 REVISED RATES							
19	Long-Term Debt		$ 1,654,026	56.16%	5.98%	3.36%	$ 98,947	
20	Unfunded Debt	$ 157,150						
21	Adjustment, Revised Rates	45	157,195	5.34%	3.75%	0.20%	5,895	
22	Preference Shares		-	0.00%	0.00%	0.00%	-	
23	Common Equity		1,133,854	38.50%	8.75%	3.37%	99,212	
24								
25			$ 2,945,075	100.00%		6.93%	$ 204,054	- Appendix G2-FORECAST, Sch 77
26								
27	CHANGE FROM 2017 REVISED RATES							
28	Long-Term Debt		$ 98,770	2.81%	-0.02%	0.15%	$ 5,466	
29	Unfunded Debt	$ (82,349)						
30	Adjustment, Revised Rates	219	(82,130)	-2.81%	1.00%	-0.08%	(2,329)	
31	Preference Shares		-	0.00%	0.00%	0.00%	-	
32	Common Equity		10,417	0.00%	0.00%	0.00%	912	
33								
34			$ 27,057	0.00%		0.07%	$ 4,049	

Appendix H

NATURAL GAS FOR TRANSPORTATION

Natural Gas for Transportation

June 2013

Table of Contents

1. INTRODUCTION

The following appendix will provide details on FEI's Natural Gas for Transportation (NGT) program.

FEI's NGT program consists of the provision of compressed natural gas (CNG) or liquefied natural gas (LNG) for the purpose of providing a suitable vehicle fuel for transportation applications. Traditional utility services are focused on delivery of low pressure natural gas to customer locations. This service does not provide the fuel to the customer in a form that is useable for transportation applications. To provide a useable CNG or LNG service, the traditional utility service offering must be supplemented, either by FEI or by other parties, by providing a fueling station service to provide a complete service that is useable by the customer.

FEI's approved General Terms and Conditions (GT&C) 12B set out the terms on which FEI can own and operate such stations. GT&C 12B apply to the "installing and maintaining a CNG fueling station, including, but not limited to, the compression, gas dryer/dehydrator, high pressure storage, dispensing equipment; and dispensing of compressed natural gas". For LNG assets, GTC 12B apply to "the installing and maintaining of LNG fueling station, including, but not limited to, the storage, vaporizer, pump, dispensing equipment; and dispensing of liquefied natural gas."

In addition, FEI may also provide fueling station services under the provisions of the Greenhouse Gas Reduction (Clean Energy Act) Regulation (the GGRR) issued May 14, 2012 by the government of British Columbia. This regulation enables public utilities to make expenditures of up to $12 million to own and operate CNG fueling stations and infrastructures and make expenditures of up to $30.5 million to own and operate LNG fueling stations and infrastructure.

This appendix is organized as follows:

Section	Section Title	Purpose
1	Introduction	Section 1 speaks to the regulation enabling the expansion of the NGT market and the regulatory history of FEI's NGT program
2	CNG and LNG Classes of Service	Section 2 demonstrates FEI's compliance with the Commission recommendation to segregate the NGT Fueling station service from traditional gas business
3	CNG and LNG Supply	Section 3 outlines FEI's ability to supply Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG)
4	Forecast Demand	Section 4 builds on the market enabling incentives, to forecast expected vehicle additions and ultimately LNG and CNG demand
5	NGT Fueling Station and Capital Requirements Forecast	Section 5 identifies the fueling stations required to fill the vehicles that are contributing to the CNG and LNG demand

Section	Section Title	Purpose
6	Cost of Service for NGT	Section 6 summarizes the cost of service for these stations and the net delivery rate reduction benefits to traditional natural gas ratepayers
7	Conclusion	Section 7 describes how FEI's role in the continued development of the NGT market in B.C. will provide benefits to all natural gas ratepayer customers and will assist the Province in achieving its greenhouse gas reduction initiatives

1.1 REGULATORY HISTORY

1.1.1 Initiation of the NGT Program

On December 1, 2010, FEI filed an Application for Approval of GT&Cs for CNG and LNG Service. The proposed section 12B of FEI's GT&C was designed to facilitate the development of both CNG and LNG refueling stations on the FEI distribution system that would be owned and operated by FEI. The Commission approved revised GT&C 12B in Order G-14-12 dated February 7, 2012.

In 2011 and 2012 FEI filed applications with the BCUC for CNG and LNG service under GT&C 12B. The Commission has approved CNG service to Waste Management,[1] to the general public from FEI's Surrey Operations Centre,[2] and to BFI Canada.[3] In 2012, the Commission issued interim approval under GT&C 12B for FEI to own, construct and operate a refueling station for Vedder Transport Ltd.[4]

1.1.2 GGRR Incentive Funding

On May 14, 2012, the government of British Columbia enacted the Greenhouse Gas Reduction (Clean Energy Act) Regulation (the GGRR) that enables public utilities to:

1. Provide grants or zero-interest loans (and related expenditures) of up to $62 million in total for the purchase of eligible natural gas vehicles operating in British Columbia;

2. Make expenditures of up to $12 million to own and operate CNG fueling stations and infrastructures; and

3. Make expenditures of up to $30.5 million to own and operate LNG fueling stations and infrastructure.

1 Order G-128-11, dated July 19, 2011.
2 Order G-165-11A, dated September 26, 2011.
3 Order C-6-12, dated April 30, 2012 and Order G-78-13, dated May 14, 2013.
4 Order C-11-12.

The rate treatment of these expenditures was approved for FEI in BCUC Order G-161-12 on October 29, 2012. Order G-161-12 approved the NGT Incentives Account to capture costs related to Prescribed Undertaking 1: Vehicle Incentives or Zero Interest Loans. Order G-161-12 also approved the Fueling Stations Variance Account to capture costs related to Prescribed Undertaking 2: CNG Stations and Prescribed Undertaking 3: LNG Stations. The Order approved the recovery of the balances in these accounts from all non-bypass natural gas customers.

On April 11, 2013, the BCUC issued Order G-56-13 which addressed non-grant related issues with respect to the GGRR. On the same date the Commission also issued its Reasons for Decision for Order G-161-12 and Order G-56-13. The Reasons for Decision provided a number of directives with respect to Prescribed Undertakings 1 and 2. Amongst other items, Order G-56-13 states: "The Commission Panel agrees and confirms the Commission's role does not include reviewing whether FEI ought to have negotiated different terms and conditions for these agreements with NGT customers."

FEI subsequently received approval for the rate treatment of "Phase 3" GGRR Incentives of $5.6 million in BCUC Order G-67-13 dated April 30, 2013.[5] The BCUC determined that the most fair and reasonable treatment is to include these expenditures as part of the $62 million funding limit established for Prescribed Undertaking 1 under the GGRR. As a result, FEI is not permitted to spend more than $56.4 million in any further funding in this area.

Following the GGRR announcement in May 2012, FEI launched its first round of funding for vehicles. Section 4 of this appendix summarizes the incentive awards and status for FEI's NGT incentive program. The next round of funding for CNG vehicles began in April of 2013.

The rates and rate design related to each new fueling station agreement will be submitted in separate applications to the BCUC for review and approval.

FEI filed its Application for Approval to Amend Rate Schedule 16 on a Permanent Basis (Rate Schedule 16 Amendment Application) on September 24, 2012. This proceeding is related to LNG supply from FEI's LNG facilities for recipients of grants under the GGRR. Pursuant to the Rate Schedule 16 decision, Order G-88-13 received on June 4, 2013, FEI will provide an evidentiary update to this application once the decision has been fully evaluated.

1.1.3 The AES Inquiry Report

On December 27, 2012, the BCUC issued its Report on the Inquiry into the Offering of Products and Services in Alternative Energy Solutions and Other New Initiatives (AES Inquiry Report). The AES Inquiry Report has implications for FEI's CNG-LNG Service offering and the use of GT&Cs 12B.

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[5] As per the directives in Order G-67-13, FEI will transfer the $5.6 million for the 2010-2011 Incentives from the NGV Incentives deferral account approved by Order G-44-12 to the NGT Incentives Account approved by Order G-161-12. The NGV Incentives deferral account will be closed subsequent to the transfer.

Among other items within the AES Inquiry Report, the Commission has found the following key items with respect to CNG and LNG Services (at p. 52):

> "• *CNG/LNG Fueling Stations are not extensions of the distribution system;*
>
> • *CNG/LNG fuelling infrastructure has no natural monopoly characteristics;*
>
> • *It is not in public interest to provide FEI with a competitive advantage in this industry by allowing FEI to subsidize the costs of service with existing ratepayer funds;*
>
> • *FEI must provide CNG/LNG Service without using any potential economic leverage it has as a public utility; and*
>
> • *GHG emission reductions provide a justification for FEI's proposed NGV programs, [but] FEI's ratepayers must be insulated, to the greatest extent possible, from the costs and risks of the program."*

The AES Inquiry Report directed (at pages 53 and 62) that any "CNG [and LNG] activities undertaken as Prescribed Undertakings, are to be structured as a Separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit." The AES Inquiry Report states that there is no CPCN requirement for CNG-LNG services undertaken within as prescribed undertakings.[6]

The AES Inquiry Report recommends that the FEU undertake CNG and LNG activities outside the prescribed undertakings in a non-regulated business.

With respect to the approved existing CNG fueling stations, the AES Inquiry Report states (at page 54):

> *"The Panel notes that the BFI CNG station is ordered to be in a Separate Class of Service. The Waste Management CNG Station was approved within the existing natural gas class of service, subject to the conditions contained in its approval. While the Panel believes it would be appropriate to have the Waste Management CNG Station within the CNG Class of Service, this report is a forward looking document and does not apply to previous decisions, unless specific issues were referred to this Inquiry. The Panel does not see this report as directing any change to the BFI or Waste Management Decisions".*

[6] AES Inquiry Report, at pages 55, 62, 63.

While no direction was provided with respect to the existing Vedder LNG station, as discussed below, subject to any further direction to the Commission, FEI has determined that the Vedder station should be in a separate class of service.

2. CNG AND LNG FUELING STATION CLASSES OF SERVICE

Based on previous Commission decisions and the directives and recommendations of the AES Inquiry Report, FEI has determined that four NGT classes of service are required to account for CNG and LNG stations constructed in compliance with either the GGRR requirements or GT&C 12B.

The need for four separate classes of services arises from two orders in particular:

- BCUC Order C-6-12 regarding the BFI CPCN, item 3 of which directed FEI to establish two new classes of service, one for CNG Service and one for LNG Service, and
- The AES Inquiry Report (Order G-201-12) which determined that "CNG activities done under the Prescribed Undertaking should be structured as a separate Class of Service with the costs to be recovered from the traditional gas utility ratepayers, to the prescribed limit."

FEI has therefore reclassified its existing and forecasted CNG and LNG stations into four classes of service. The four classes of service include:

1. Non-GGRR CNG Stations
2. Non-GGRR LNG Stations
3. GGRR CNG Stations
4. GGRR LNG Stations

These classes of service will not have an impact on FEI's traditional natural gas rate payers' revenue requirement within this application unless otherwise specified in this appendix and only up to the prescribed limit within the GGRR.

Table H-1 below identifies in which class of service the current and forecast CNG and LNG stations will be classified.

Table H-1: CNG and LNG Station Class of Service

Station	Class of Service	Related Order or Report	Characteristics
Waste Management	Non-GGRR CNG	G-128-11	CNG Service, Application submitted consistent with GT&C 12B
BFI	Non-GGRR CNG	C-6-12	CNG Service, Application submitted consistent with GT&C 12B
Vedder Transport (Permanent LNG Station)	Non-GGRR LNG	C-11-12	LNG Service, Application submitted consistent with GT&C 12B
Surrey & Burnaby[7] Operations CNG Pumps	Non-GGRR CNG	G-165-11A[8]	CNG Service
Kelowna School District	Non-GGRR CNG	N/A	CNG Service, Application will be submitted consistent with GT&C 12B
Forecast GGRR CNG Stations	GGRR CNG	G-161-12 G-56-13	CNG Service, Applications to be submitted consistent with GGRR
Forecast GGRR LNG Stations	GGRR LNG	G-161-12 G-56-13	LNG Service, Applications to be submitted consistent with GGRR

For the Kelowna School District fueling station project, fueling station expenditures were incurred in 2009 and 2011 and prior to the establishment of the GGRR and the initiation of the AES Inquiry. On May 1, 2012 the BCUC issued Letter L-29-12 which clarified the CPCN threshold and regulatory process for the Kelowna School District project. Letter L-29-12 states:

> *"The Commission Panel notes that the construction of the Kelowna SD CNG fuelling station was completed in 2011 and FEI has been providing CNG fuelling service since September 1, 2011. The lack of express exclusion from a CPCN requirement for the Kelowna SD in Order G-9-12 was due to FEI's delay in seeking approval for the revised GT&C 12B and the corresponding delay in filing a service agreement with the Kelowna SD. The Commission Panel believes that the Kelowna SD project has the potential of undergoing a more routine regulatory review and that no public interest will be served by compelling the Kelowna SD project to undergo a CPCN review."*

The letter emphasizes that the process for the Kelowna School District project (and others prior to the decision in the AES Inquiry) are *ad hoc*. Given the direction in letter L-29-12, FEI intends to apply under GT&Cs 12B for the Kelowna School District fueling station project.

[7] The Burnaby Operation's CNG Pump is for company use only and does not have a dispensing rate in place at this time.
[8] Order G-165-11A is only applicable to Surrey Operations Centre Pump.

The primary difference between the Non-GGRR and GGRR stations is that the GGRR allows FEI to recover costs of the GGRR stations from traditional natural gas utility ratepayers up to the prescribed limit, whereas FEI does not have this allowance for its Non-GGRR stations.

While the GGRR allows for recovery of costs from traditional natural gas ratepayers, FEI expects to recover the cost of service for fueling stations from NGT customers through station rates. The recovery of costs under the GGRR with respect to traditional natural gas ratepayers is only applicable for any shortfalls in cost of service recoveries from NGT customers.

Having four distinct classes of service will enable FEI to:

- Eliminate non-essential deferral accounts related to Non-GGRR stations;
- Account for costs related to Non-GGRR stations to ensure no cross-subsidization occurs; and
- Account for costs related to GGRR stations to ensure only costs up to the prescribed limit, less recoveries from NGT customers from fueling station rates, are recovered from traditional Natural Gas ratepayers.

Accordingly, the cost of service for each of the NGT fueling station classes of service has been removed from the traditional natural gas ratepayer revenue requirement financial schedules within this Application unless otherwise approved and identified within this appendix. Revenues from traditional tariffs that are utilized to provide the broader NGT service to customers, for example delivery tariffs for CNG customers, are however, included in the revenue requirement financial schedules within this Application to the benefits of traditional natural gas ratepayers.

FEI intends to pursue CNG/LNG activities under Prescribed Undertakings 2 and 3 of the GGRR, which authorizes expenditure limits for CNG and LNG of $12.0 and $30.5 million respectively, over the period of the prescribed undertaking. Although no CPCN approvals will be required for these expenditures and stations, FEI will still file for approval of the customer rate with the BCUC. The terms and conditions of GGRR fueling station agreements are generally limited by the following term:

> *"At least 80% of the energy provided at each station during the undertaking period is provided to one or more persons under a take-or-pay agreement with a minimum term of 5 years".*[9]

On May 13, 2013 FEI submitted its first application for rate approval under the GGRR in the form an agreement with Smithrite Disposal Ltd. for CNG fueling station service. The agreement

[9] Greenhouse Gas Reduction (Clean Energy) Regulation, Prescribed Undertaking 2, paragraph 2(c) and 3(c)

negotiated with Smithrite meets to the parameters under the GGRR. This application is presently before the Commission.

3. CNG AND LNG SUPPLY

3.1 *LNG SUPPLY*

The supply of LNG within BC is limited to the FEI's Tilbury LNG facility and FEVI's Mt. Hayes LNG facility. In order to provide LNG supply to recipients of grants under the GGRR, FEI filed its Rate Schedule 16 Amendment Application to amend the existing Rate Schedule 16 Pilot Program to a permanent rate offering. Among the various approvals sought in the Rate Schedule 16 Amendment Application was an increase to the volume of LNG that would be available from Tilbury and Mt. Hayes from the current pilot cap of 1,040 GJ/d to 42,000 GJ/wk (6,000 GJ/d) (3,200 GJ/d from Tilbury and 2,800 GJ/d from Mt. Hayes). The Commission issued Order G-88-13 on June 4, 2013, which amended Rate Schedule 16, but denied several of FEI's requests. FEI will provide an evidentiary update to this application once Order G-88-13 and the accompanying decision has been fully evaluated.

3.2 *CNG SUPPLY*

Over the past few years, FEI has constructed two CNG fueling stations in BC. FEI has fueling station agreements with BFI and Waste Management which conform to GT&C 12B. The Waste Management agreement was developed based on previously proposed GT&Cs, and was accepted "on an exception basis only".

Presently, CNG customers under FEI Tariff Supplements J-1 and J-2 in FEI's approved GT&C 12B generate delivery revenues under Rate Schedule 25.[10] Revenues collected under Rate Schedule 25 include a fixed monthly charge, delivery and demand charge. Revenues generated by CNG customers positively impact delivery margin, which is a benefit to all natural gas for distribution customers by reducing the pressure on delivery margin rate increases.

4. FORECAST DEMAND FOR NGT

This section provides forecasts related to GGRR expenditures expected to be awarded over the remaining prescribed undertaking period, natural gas vehicle additions, and overall CNG and LNG demand for transportation.

The forecasts provided in this section differ from the forecasts presented in the original GGRR Application, which was filed with the Commission on August 21, 2012. The forecasts presented

[10] Rate Schedule 25 is FEI's General Firm Service used to serve larger volume customers who use gas for more than space heating and generally have a higher load factor than residential and commercial customers due to their consumption patterns.

in this section contain actual data up to and including March 2013 as FEI has newer information regarding vehicle additions and actual consumption to date.

4.1 FORECAST GGRR EXPENDITURES

In 2012, GGRR funding rewards at 75 percent of the funding level were delayed to 2013 and thus no GGRR expenditures were made in 2012.[11] The table below provides a forecast of GGRR expenditures over the remaining prescribed undertaking period for FEI only. These GGRR expenditures will be tracked and accounted for in a separate NGT Incentives deferral account.

Table H-2: FEI Forecast GGRR Expenditures ($000s)

Incentive Forecast (2013 update for FEI)	pre-2013	2013F	2014F	2015F	2016F	2017F
GGRR Phase 3 Incentives	$ 5,573					
Round 1		$ 12,277				
Round 2		$ 12,037				
Total Vehicle Incentives	$ 5,573	$ 24,314	$ 5,624	$ 4,000	$ 3,000	$ -
Marine	$ -	$ 3,000	$ 3,500	$ 2,500	$ 2,000	$ -
Admin, Education, Safety Training	$ 430	$ 2,020	$ 1,850	$ 1,550	$ 1,250	$ -
Total	$ 6,003	$ 29,334	$ 10,974	$ 8,050	$ 6,250	$ -
Cumulative	$ 6,003	$ 35,337	$ 46,311	$ 54,361	$ 60,611	$ 60,611

4.2 FORECAST VEHICLE ADDITIONS

Using assumptions regarding the average price differential between a diesel fueled vehicle and natural gas fueled vehicle, FEI has forecasted the number of vehicle additions by year based on the expected GGRR incentives from Table H-3.

The table below provides a forecast of vehicle additions by type over the remaining prescribed undertaking period.

Table H-3: Forecast Vehicle Additions (FEI Only)

Vehicle Additions (FEI)	2013F	2014F	2015F	2016F	2017F
Vocational trucks	58	153	63	56	56
Buses	2	36	21	19	19
Class 8 tractors	42	202	72	77	67
Marine	-	-	1	1	1
Total NGT Fleet	102	392	156	153	142

[11] In 2010 and 2011 Demonstration Period, FEI awarded $5.573 million for purchasing NGVs. The determination on the treatment of these expenditures was approved in BCUC Order G-67-13 on April 30, 2013.

4.3 FORECAST GAS DEMAND FROM NGT

The table below provides a forecast of NGT demand volumes to the end of the prescribed undertaking period of the GGRR based on the expected number of vehicle additions as presented in the table above.

Table H-4: FEI Natural Gas Demand (GJ/Year) Forecast for NGT

Load Additions (GJ/yr)	2013F	2014F	2015F	2016F	2017F
Vocational trucks (CNG)	160,021	369,680	432,372	488,695	544,276
Buses (CNG)	4,844	71,426	92,366	111,178	129,743
Class 8 tractors (LNG)	256,511	1,371,319	1,658,349	1,967,326	2,235,744
Marine (LNG)	-	-	150,000	250,000	350,000
Total NGT Fleet	421,375	1,812,426	2,333,087	2,817,199	3,259,763

For LNG demand, the maximum volume that can be offered under the RS16 tariff approved by Order G-88-13 is approximately 2.2 petajoules (PJ) per year (or, 42,000 GJ/wk). The Commission Panel approved a maximum quantity of LNG for sale under RS16 of 3,200 GJ per day from Tilbury and approved a maximum quantity of LNG for sale under RS16 of 2,800 GJs per day from Mt. Hayes, once it has a tanker truck loading facility. These are hard caps applicable to each facility and cannot be combined.

The forecast presented in the table above is for LNG demand to increase steadily to 2016, at which point demand will be about 2.2 PJ per year and be about equal to the maximum cap in the Rate Schedule16 permanent tariff rate.

The addition of LNG marine vessels and LNG heavy duty trucks will be the largest contributors to overall LNG demand for FEI in the long run. The current forecast is that under the approved daily supply caps or 42,000 GJ/wk, there will be sufficient supply to serve LNG demand until at least 2016.

Based on the forecast provided in the table above, additional LNG supply will likely be required after 2017 as demand will outstrip the quantity that will be available from the Rate Schedule 16 tariff. On the other hand, if LNG demand grows more quickly than forecast before 2017, there may be the need for the addition of another liquefaction facility or facilities to supply the BC market.

5. NGT FUELING STATIONS & CAPITAL REQUIREMENTS FORECAST

Based on the forecasted volume of natural gas demand for CNG and LNG and the expenditure of vehicle incentives as permitted under the GGRR, FEI has forecasted the number of fueling stations for both CNG and LNG that it will need to construct in the table below.

Table H-5: NGT Fueling Stations Forecast Built by FEI

FEI Station Additions For:	2013F	2014F	2015F	2016F	2017F
Vocational Trucks	3	3	1	1	1
Buses	0	0	0	0	0
Class 8 Tractors	0	3	1	1	1
Mobile LNG	3	1	1	1	1
Total Stations	6	7	3	3	3

The numbers presented in the table above assume that all expenditures for vehicle incentives under the GGRR are awarded to qualifying customers over the prescribed undertaking period and that FEI will construct half of the CNG fueling stations required to serve CNG demand.

The other half of the required CNG fueling stations are assumed to be built by independent third parties. FEI believes that this is a reasonable assumption and therefore provides a conservative forecast of the number of CNG fueling stations that it will construct.

Based on FEI's past experience with respect to total capital requirements to build fueling stations (LNG and CNG), the figures presented in the table below assume a total capital charge for each type of fueling application:

- Vocational Trucks (CNG) - $1.0 million
- Buses (CNG) - $1.5 million
- Class 8 Tractors (LNG) - $2.5 million
- Mobile LNG - $0.75 million

Based on the forecasted station capital requirements listed above and the anticipated addition of NGT fueling stations as described in Table H-5, FEI forecasts to spend the amounts described in Table H-6 on CNG and LNG fueling stations after 2013.[12] For vocational trucks and buses (CNG stations), FEI is assuming that it will construct half of the fueling stations required to serve demand for these two segments of the NGT market.

[12] 2013 CNG station capital requirement of $3.5 million is a projection based on current discussions with potential CNG customers

Table H-6: NGT Fueling Station Capital Requirements Forecast ($ millions)

Fueling Station Expenditures ($ millions)	2013F	2014F	2015F	2016F	2017F	2018F
Vocational Trucks	$ 3.50	$ 3.00	$ 1.00	$ 1.00	$ 1.00	$ -
Buses	$ -	$ -	$ -	$ -	$ -	$ -
Class 8 Tractors	$ -	$ 7.50	$ 2.50	$ 2.50	$ 2.50	$ -
Mobile LNG	$ 2.25	$ 0.75	$ 0.75	$ 0.75	$ 0.75	$ -
Total Capital	$ 5.75	$ 11.25	$ 4.25	$ 4.25	$ 4.25	$ -

5.1 OPERATIONS AND MAINTENANCE (O&M)

O&M expenses related to the operation of the GGRR CNG and LNG fueling stations are recovered directly from the customer of that fueling station through the rates for those customers.

Drawing on FEI's experience in constructing natural gas fueling stations, the forecast O&M expenses for each type of application are as follows.

Table H-7: Forecast Annual Fueling Station O&M

Fueling Application	O&M per Year per Station ($)
Vocational trucks	$ 50,000
Buses	$ 70,000
Class 8 Tractor	$ 80,000
Mobile LNG	$ 90,000

Table H-8 provides a forecast of O&M expenses related to the forecasted number of NGT GGRR fueling stations that FEI expects to construct over the next five years. The figures presented in the table below add O&M expenses for stations that will be constructed in subsequent years and are adjusted for expected in-service dates, thus the figures presented are a cumulative total of O&M dollars that will be expended over the next five years.

Table H-8: NGT GGRR Fueling Station O&M Forecast

Annual Station O&M ($ thousands)	2013F	2014F	2015F	2016F	2017F	2018F
Vocational Trucks	$ 62	$ 307	$ 365	$ 423	$ 483	$ 493
Buses	$ -	$ -	$ -	$ -	$ -	$ -
Class 8 Tractors	$ -	$ 172	$ 335	$ 428	$ 523	$ 537
Mobile LNG	$ 107	$ 363	$ 457	$ 553	$ 651	$ 661
Total O&M	$ 169	$ 842	$ 1,157	$ 1,404	$ 1,657	$ 1,691

5.2 OVERHEAD AND MARKETING (OH&M) CHARGE

BCUC Order G-128-11, dated July 19, 2011 directed FEI to include an overhead and marketing (OH&M) charge that would be recovered from NGT station customers through each customer's station fueling rate. On May 14, 2013, BCUC issued Order G-78-13 directing FEI to charge NGT customers $0.52 per GJ as the OH&M rate.

The forecast OH&M collected from each of the station customers is accounted for as an Other Revenue credit in the Natural Gas Class of Service.

The OH&M recovery over the 2014 – 2018 period is expected to total approximately $5 million. This represents a $3.5 million net benefit flowing to traditional natural gas ratepayers when compared to the forecast expense of $1.5 million[13]. Table H-9 below shows the forecast OH&M expense and recovery from NGT customers based on the $0.52 per GJ charge. The OH&M recoveries will continue over the term of each station contract and FEI expects that, as NGT demand increases, recoveries will surpass expenses for a net benefit to FEI's core customers as shown in Table H5-5 for all years.

Table H-9: OH&M Forecast Recovery

OH&M Recovery ($000)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast Total
Forecast OH&M	371	390	379	378	-	**1,518**
O&M Recovery	(490)	(869)	(1,072)	(1,278)	(1,304)	**(5,012)**
Total Deficiency (Surplus) Collected	**(119)**	**(479)**	**(693)**	**(900)**	**(1,304)**	**(3,494)**

In FEI's view, the total OH&M recoveries far exceed the amount of actual O&M costs embedded in the natural gas class of service, and at the current rate represents a cross subsidization from the NGT classes of service.

Order G-44-12 dated April 12, 2012 regarding the FEU's 2012-13 RRA approved overhead, marketing, business development and customer education related to natural gas vehicle (NGV) services of $569 and $601 for years 2012 and 2013, respectively. If FEI were to use those amounts and escalate the labour component by 2.5 percent per year, the $0.52 per GJ OH&M rate recovered from the NGT classes of service still results in a cross subsidization from the NGT class to natural gas distribution customers of approximately $1.5 million in total from 2012 through 2018, with the cross subsidization beginning in 2015. Table H-10 shows the approved amounts, forecast and the cross subsidization that is forecast to occur.

[13] BFI CPCN Order G-150-12 Compliance Filing, Table 3, years 2014 to 2017

Table H-10: OH&M Forecast Recovery

Forecast OH&M ($000)	Approved 2012	Approved 2013	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018	Forecast Total
Labour	508	526	539	553	567	581	-	**3,274**
Customer Education	61	75	80	90	70	60	-	**436**
Total	**569**	**601**	**619**	**643**	**637**	**641**	**-**	**3,710**
OH&M Recovery @ $0.52/GJ	(92)	(161)	(490)	(869)	(1,072)	(1,278)	(1,304)	**(5,264)**
Total Deficiency (Surplus) Collectec	**478**	**440**	**129**	**(226)**	**(435)**	**(637)**	**(1,304)**	**(1,555)**

FEI has included the OH&M charge as a component of the fueling station rate for the following stations:

- BFI
- Vedder Transport
- Kelowna School District proposed station
- All forecast GGRR CNG Stations
- All forecast GGRR LNG Stations

FEI notes that with reference to the OH&M charge, BFI Order G-78-13 was not applied retroactively and, therefore, OH&M is not recovered from Waste Management or the Surrey or Burnaby pumps.

6. COST OF SERVICE FOR NGT

6.1 *GGRR CNG AND LNG CLASSES OF SERVICE*

FEI has used a cost of service model to calculate a forecast cost of service for the GGRR CNG and LNG classes of service. The GGRR CNG class of service schedules are attached to this appendix as Schedules 1 through 9; the GGRR LNG Class of Service schedules are Schedules 10 through 18 and include the following schedules:

- Cost of Service
- O&M and Property Tax
- Income Tax
- Capital Cost Allowance (CCA)
- Rate Base

- Capital Spending
- Gross Plant in Service
- Accumulated Depreciation
- Deferred Charges

FEI has used forecasted capital additions provided in Table H-6, derived from the GGRR Vehicle Incentives and supporting stations from Table H-5 of this document. The forecast O&M is also derived from the station additions and is shown in Table H-8 of this document. FEI has included a forecast of property taxes based on the municipality in which the station is located, if known, and an average property tax rate of the existing stations if unknown. Incremental insurance costs of approximately $1 thousand per station are also included. For financing costs (debt and equity), the NGT classes assume the same capital structure as the FEI Natural Gas for Distribution class.

Deferrals Schedule (9) reflects a negative salvage provision which is calculated to collect the forecasted cost to remove the station assets at the end of their depreciable lives.

6.1.1 Fueling Station Variance Account Forecast Additions

Prescribed Undertaking 2 of the GGRR authorizes expenditure limits for CNG and LNG of $12.0 million and $30.5 million respectively, over the Undertaking period.

Costs and recoveries for CNG and LNG stations pursued under the prescribed undertakings are recoverable from traditional utility ratepayers as required by the GGRR. The Fueling Station Variance Account (FSVA) was established pursuant to Order G-161-12 whereby the account would capture "the total revenue surplus or deficiency pertaining to fueling station facility costs that have not been forecast in rates, as well as the administration and application costs…"

FEI has forecast Administration and Marketing additions to the FSVA pursuant to Order G-161-12. This forecast is representative of the prescribed limits of $240 thousand and $250 thousand for CNG and LNG stations respectively prorated evenly over regulation years 2013 through 2017.

An annual Deficiency / (Surplus) is calculated and will also be included as an addition to the FSVA deferral account. The Deficiency / (Surplus) reflects the under / (over) collection of the cost of service in any given year and is calculated by subtracting the revenue collected from the levelized contract rate of each station from the forecast cost of service for the class[14]. Table H-

[14] Pursuant to the Rate 16 decision, Order G-88-13 received on June 4, 2013, FEI will provide in evidentiary update to this application the FSVA additions once the decision has been fully evaluated

11 shows the gross additions to the FSVA for 2014 through 2018. The 2014 addition is included on Schedule 49, line 16 of the Financial Schedules.

Table H-11: FSVA Gross Addition Forecast

($000)	Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
FSVA Account Gross Additions	238	61	71	14	(137)

For each station constructed over the term of the GGRR, a station rate is calculated so that, over the life of the contract, the revenue collected equals the cost of service so that the designed net impact to traditional natural gas rate payers is zero.

In addition, an excess (of contract demand) fueling rate is also calculated for volumes sold in excess of contract demand. The excess recoveries collected will credit the FSVA and be returned to traditional natural gas rate payers through amortization of the FSVA.

The FSVA provides a mechanism to capture all GGRR fueling stations variances (surplus) and deficiencies including Administration and Marketing costs specific to these stations. FEI has endeavoured to forecast additions to the FSVA within this appendix. However, as has been approved, all deficiencies and surpluses will be accounted for in the FSVA and amortized into core customers' rates over three years.

6.2 NON-GGRR CNG AND LNG CLASSES OF SERVICE

Pursuant to the BFI Decision and the AES Inquiry Report, FEI is accounting for its existing CNG and LNG stations in the Non-GGRR CNG and LNG classes of service. FEI was directed to account for BFI in this manner and although not directed to, FEI believes that it is appropriate to account for its other Non-GGRR stations in the spirit of both the BFI Decision and AES Inquiry Report.

FEI has five stations that are included in the Non-GGRR CNG and LNG Classes of Service:

1. Waste Management
2. BFI
3. Vedder Transport
4. Surrey Operations CNG Pump
5. Burnaby Operations CNG Pump

Each of the Waste Management, BFI and Vedder stations have contracted rates in place for both the contract demand (take-or-pay) and an excess fueling rate for volumes sold in excess of contract demand.

Burnaby Operation's CNG Pump is for company use only and does not have a dispensing rate in place at this time. For the purposes of setting rates within this application, the Burnaby operations pump assets and annual Operation and Maintenance expenses have been removed from the Natural Gas for Distribution class of service and included in the Non-GGRR CNG Class of service. However, since the Burnaby operations pump is used by FEI Fleet servicing non-bypass ratepayers exclusively, the cost of service of this pump will show as a debit in the Application, Section C2 - Other Revenues and as a recovery in the NGT Class of Service.

Surrey Operation's CNG Pump has a rate in place pursuant to BCUC Order G-165-11A through Rate Schedule 6P and sells CNG under this Rate Schedule. The rate schedule includes a rate for the compression service. Commencing January 1, 2014 FEI will account for this recovery in the Non-GGRR CNG Class of Service as an offset to the cost of service for this pump. A portion of the recoveries come from CNG sales to the public and a portion from CNG sales to FEI's fleet servicing Core ratepayers. The recovery from FEI fleet will show as a debit in the Application, Section C2 - Other Revenues.

Accounting for these five stations in separate Non-GGRR classes of service allows FEI to capture all costs and recoveries related to these assets and will ensure that these costs and recoveries are not borne by traditional natural gas ratepayers. Since these stations are separated from the natural gas class of service, the disposition of the existing deferral accounts which reside in the natural gas class of service related to these fuelling stations is addressed below.

6.2.1 BFI Costs and Recoveries

In accordance with Commission Orders C-6-12 and G-150-12, FEI is to include all other amounts paid by BFI for volumes in excess of the 'take or pay' commitment in a new rate base deferral account separate from the deferral account approved in the Waste Management Decision. The deferral account is to capture incremental CNG Service recoveries received from actual volumes purchased in excess of minimum take or pay commitments, with the disposition to be determined at a future date.

BFI is in a class of service for which natural gas ratepayers are not accountable. BFI has a station refuelling rate contracted for seven years. Therefore, it is no longer necessary to accumulate a deficiency or surplus in this deferral since all deficiencies or surpluses related to BFI will be accounted for in the Non-GGRR CNG Class of Service and be to the account of the shareholder and not FEI's traditional natural gas ratepayers.

Consequently, to eliminate any impact the balance of this deferral may have on traditional natural gas ratepayers, FEI is requesting to transfer the balance of this account to the Non-GGRR CNG Class of Service and will expense it there effective January 1, 2014.

6.2.2 CNG & LNG Service Recoveries

The CNG & LNG Service Recoveries account, approved by Order G-128-11, captures the incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand. The concept of this account was to capture any excess station capital and O&M recoveries and amortize them back into core customers' rates.

Since the Non-GGRR CNG and LNG classes of service do not impact core customer rates, effective January 1, 2014, FEI will no longer accumulate excess station recoveries from the Waste Management and Vedder stations within this account. Please refer to Section D4-4.4.4 which includes a discussion on the amortization of the December 31, 2013 balance.

6.3 NGT REVENUE, COST OF GAS AND DELIVERY MARGIN FORECAST

The NGT classes of service are designed to categorize fueling station assets into separate classes so as to minimize or otherwise control the impact that these stations costs and recoveries have on the traditional natural gas ratepayer. However, the associated sale of natural gas via CNG or LNG through these station assets remains a component of the traditional natural gas ratepayer's revenue.

Currently, FEI delivers CNG and LNG through the GGRR and non-GGRR stations using Rate Schedules 6P, 25 and 16. FEI has used the forecast volumes from this appendix to calculate revenue, cost of gas and delivery margin at existing rates. It should be noted that the Rate Schedule 16 impacts to revenues, gas costs and delivery margins are interim and awaiting a decision on the Rate Schedule 16 Amendment Application.

The following three tables identify, by the three rate schedules listed above, the forecast of gas (CNG and LNG) volumes sold, associated delivery margin, cost of gas (if the rate schedule is a not a transportation rate) and revenue.

Table H-12: Volume, Delivery Margin Cost of Gas and Revenue forecast for Rate Schedule 6P NGT Customers[15]

Volume, Revenue, Margin under RS 6P	2014F	2015F	2016F	2017F	2018F
Surrey Operation Pump (GJ)	4,725	4,725	4,725	4,725	4,725
Total Delivery Margin ($)	$ 19,075	$ 19,075	$ 19,075	$ 19,075	$ 19,075
Total Cost of Gas ($)	$ 15,971	$ 15,971	$ 15,971	$ 15,971	$ 15,971
Total Revenue ($)	$ 35,045	$ 35,045	$ 35,045	$ 35,045	$ 35,045

[15] Volume represents the contract volume for existing stations and GGRR forecast volumes for proposed stations whereas Table H-4 represents all GGRR and Non-GGRR volume (contract and excess of contract demand).

Table H-13: Volume, Delivery Margin and Revenue forecast for Rate Schedule 25 NGT Customers[16]

Volume, Revenue, Margin under RS 25	2014F	2015F	2016F	2017F	2018F
CNG Service Volume (GJ)					
Waste Management (Contract Demand)	18,996	18,996	18,996	18,996	18,996
BFI (Contract Demand)	60,000	60,000	60,000	60,000	60,000
Kelowna School District	4,665	4,665	4,665	4,665	4,665
City of Surrey	1,000	1,000	1,000	1,000	1,000
All Other GGRR	315,442	399,073	474,208	548,354	548,354
Total Volume (GJ)	400,103	483,734	558,869	633,015	633,015
Total Revenue/Delivery Margin ($)	$ 292,475	$ 353,609	$ 408,533	$ 462,734	$ 462,734

Table H-14: Volume, Delivery Margin, Cost of Gas and Revenue Forecast for Rate Schedule 16 Customers[17][18]

Volume, Revenue, Margin under RS 16	2014F	2015F	2016F	2017F	2018F
LNG Service Volume (GJ)					
Vedder Transport (Contract Demand)	160,000	160,000	160,000	160,000	160,000
All Other GGRR	1,181,319	1,618,349	2,027,326	2,395,744	2,395,744
Total Volume	1,341,319	1,778,349	2,187,326	2,555,744	2,555,744
Total Delivery Margin ($)	$ 5,526,235	$ 7,326,796	$ 9,011,785	$ 10,529,663	$ 10,529,663
Total Cost of Gas ($)	$ 5,274,760	$ 7,540,703	$ 9,848,389	$ 12,171,506	$ 12,795,912
Total Revenue ($)	$ 10,800,995	$ 14,867,499	$ 18,860,174	$ 22,701,169	$ 23,325,576

The volume, delivery margins, cost of gas and revenues are components within the traditional natural gas financial schedules within this Application and are part of the overall natural gas revenue requirement.

6.4 *SUMMARY OF COSTS AND BENEFITS*

Table H-15 shows the forecast cost of service and benefits that the incentives under the GGRR are expected to produce based on past decisions and forecast spending.

16 Ibid.
17 Ibid.
18 Pursuant to the Rate 16 decision, Order G-88-13 received on June 4, 2013, FEI will provide in evidentiary update to this application, revised Rate 16 revenue, cost of gas and gross margin once the decision has been fully evaluated

Table H-15: Summary of NGT Costs and Benefits for Core Ratepayers[19]

($000)	2014F	2015F	2016F	2017F	2018F	Total
NGT Incentives and FSVA Cost of Service	7,347	8,491	9,165	8,810	8,376	42,189
OH&M Recoveries	(490)	(869)	(1,072)	(1,278)	(1,304)	(5,012)
Delivery Margin Contributions	(5,838)	(7,699)	(9,439)	(11,011)	(11,011)	(45,000)
Net (Benefit) / Cost to Core	**1,020**	**(77)**	**(1,346)**	**(3,479)**	**(3,940)**	**(7,823)**

As discussed in Section 6.1.1 above, the FSVA Additions are designed to have zero impact on core customers over time and NGT Vehicle Incentives have a maximum expenditure limit of $62 million, whereas OH&M Recoveries and Delivery Margin Contributions are expected to continue for many years into the future.

7. CONCLUSION

Since the initial CNG/LNG Application in late 2010, FEI has made progress in contracting with NGT customers for fueling station service. While adoption has been slowed due to regulatory uncertainty and other factors, FEI has forecast significant uptake in its NGT offerings going forward. FEI is evaluating these forecasts in light of Order G-88-13 dated June 4, 2013 regarding FEI's Rate Schedule 16 Amendment Application and will update the information in this Appendix as required in an evidentiary update.

Pursuant to the Commission's decisions regarding accounting for CNG and LNG station, FEI has established separate classes of service for existing CNG and LNG stations. For FEI traditional natural gas ratepayers, with the exception of the GGRR fuelling stations as permitted by AES Inquiry Report and Order G-161-12, these separate classes of service prevent cross-subsidization between the different classes of service.

[19] Pursuant to Order G-88-13 dated on June 4, 2013, regarding FEI's Rate Schedule 16 Amendment Application, FEI will provide an evidentiary update to this Application, revised Rate 16 benefits to core ratepayers and forecast LNG service uptake once the decision has been fully evaluated.

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Revenue Requirement
Schedule 1
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Revenue Requirement**							
2	Cost of Energy Sold		-	-	-	-	-	-
3	Operation and Maintenance	Schedule 2, Line 17	62	307	364	423	483	493
4	Property Taxes	Schedule 2, Line 22	14	27	32	36	41	42
5	Depreciation Expense	Schedule 8, Line 13 + Line 30	73	175	325	375	425	475
6	Amortization Expense	Schedule 9, Line 38	1	2	3	4	4	5
7	Other Revenue	Schedule 2, Line 22	-	-	-	-	-	-
8	Income Taxes	Schedule 3, Line 20	(52)	(121)	(122)	(93)	(66)	(25)
9	Earned Return	Schedule 5, Line 24	109	460	511	547	563	536
10								
11	**Annual Revenue Requirement**	Sum of Lines 2 through 9	**207**	**849**	**1,113**	**1,291**	**1,450**	**1,525**
12								
13	**Costs and (Recoveries) Transferred to Natural Gas Class of Service**							
14	OH&M Collected - NG Distn Class Other Revenue		(18)	(100)	(118)	(135)	(153)	(156)
15	Deficiency (Surplus) - NG Distn Class FSVA deferral account		86	33	(17)	(21)	(48)	(37)

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: O&M, Other Revenue and Property Tax
Schedule 2
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Gross O&M**							
2	Labour Costs		-	-	-	-	-	-
3	Vehicle Costs		-	-	-	-	-	-
4	Employee Expenses		-	-	-	-	-	-
5	Materials & Supplies		-	-	-	-	-	-
6	Computer Costs		-	-	-	-	-	-
7	Fees & Administrations Costs		-	-	-	-	-	-
8	Contractor Costs		59	301	357	415	473	483
9	Facilities		3	6	7	8	9	10
10	Recoveries & Revenue		-	-	-	-	-	-
11								
12	Non-Labour Costs		62	307	364	423	483	493
13								
14	Total Gross O&M Expenses		62	307	364	423	483	493
15								
16	(Less): Capitalized Overhead		-	-	-	-	-	-
17	Add (Less): Adjustment		-	-	-	-	-	-
17	Net O&M		62	307	364	423	483	493
18								
19	**Property Taxes**							
20	General, School and Other		14	27	32	36	41	42
21	1% in Lieu of General Municipal Tax[1]	Schedule , Line 42/1000 x 1%	-	-	-	-	-	-
22	Total Property Taxes		14	27	32	36	41	42
23								
24	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue							

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Income Tax Expense
Schedule 3
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Income Tax Expense**							
2								
3	Earned Return	Schedule 5, Line 24	109	460	511	547	563	536
4	Deduct: Interest on debt	Schedule 5, Line 23	(56)	(247)	(273)	(287)	(283)	(272)
5	Add (Deduct): Amortization Expense	Schedule 9, Line 38	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 8, Line 13 + Line 30	73	175	325	375	425	475
7	Add: Removal Cost Provision	Schedule 9, Line 17	1	2	3	4	4	5
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 9, Line 14	-	-	-	-	-	-
10	Deduct: Capital Cost Allowance	Schedule 4, Line 22	(283)	(754)	(934)	(919)	(908)	(820)
11	Taxable Income After Tax	Sum of Lines 3 through 10	(156)	(364)	(367)	(280)	(199)	(76)
12								
13	Income Tax Rate		25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	75%	75%	75%	75%	75%	75%
15								
16	Taxable Income	Line 11 / Line 14	(208)	(485)	(490)	(374)	(265)	(101)
17								
18	Total Income Tax Expense	Line 16 x Line 13	(52)	(121)	(122)	(93)	(66)	(25)
19	Adjustments		-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	(52)	(121)	(122)	(93)	(66)	(25)

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Capital Cost Allowance
Schedule 4
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**CNG Dispensing Equipment- Class 8 @ 20%**							
2	Opening Balance	Preceeding Year, Line 5	-	2,307	3,822	3,717	3,633	3,565
3	Additions	Schedule 7 , Line 10 - AFUDC	2,563	2,197	732	732	732	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	(256)	(681)	(838)	(817)	(800)	(713)
5	Closing Balance	Sum of Lines 2 through 4	2,307	3,822	3,717	3,633	3,565	2,852
6								
7	**Foundation- Class 1 @ 4%**							
8	Opening Balance	Preceeding Year, Line 11	-	825	1,499	1,675	1,844	2,006
9	Additions	Schedule 7 , Line 11 - AFUDC	842	722	241	241	241	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	(17)	(47)	(65)	(72)	(79)	(80)
11	Closing Balance	Sum of Lines 8 through 10	825	1,499	1,675	1,844	2,006	1,925
12								
13	**Natural Gas Dehydrator- Class 8 @ 20%**							
14	Opening Balance	Preceeding Year, Line 17	-	86	142	138	135	132
15	Additions	Schedule 7 , Line 12 - AFUDC	95	82	27	27	27	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(10)	(25)	(31)	(30)	(30)	(26)
17	Closing Balance	Sum of Lines 14 through 16	86	142	138	135	132	106
18								
19	**Total CCA**							
20	Opening Balance	Preceeding Year, Line 23	-	3,217	5,464	5,530	5,611	5,703
21	Additions	[1]	3,500	3,000	1,000	1,000	1,000	-
22	CCA	[2]	(283)	(754)	(934)	(919)	(908)	(820)
23	Closing Balance	Sum of Lines 20 through 22	3,217	5,464	5,530	5,611	5,703	4,883
24	1- Schedule 7 , Line 13 - Line 24 + Line 87 above - AFUDC							
25	2- Schedule 4 , Sum of detailed CCA lines							

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Rate Base
Schedule 5
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Rate Base**							
2	Gross Plant In Service- Beginning	Schedule 7, Line 7	-	3,500	6,500	7,500	8,500	9,500
3	Gross Plant In Service- Ending	Schedule 7, Line 25	3,500	6,500	7,500	8,500	9,500	9,500
4								
5	Accumulated Depreciation- Beginning	Schedule 8, Line 7	-	(73)	(248)	(573)	(948)	(1,373)
6	Accumulated Depreciation- Ending	Schedule 8, Line 25	(73)	(248)	(573)	(948)	(1,373)	(1,848)
7								
8	Contributions in Aid of Construction- Beginning	Schedule 7, Line 29	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 7, Line 32	-	-	-	-	-	-
10								
11	Accumulated Amortization- Beginning	Schedule 8, Line 29	-	-	-	-	-	-
12	Accumulated Amortization- Ending	Schedule 8, Line 32	-	-	-	-	-	-
13								
14	Net Plant in Service, Mid-Year	Sum (Lines 2 through 12)/2	1,714	4,840	6,590	7,240	7,840	7,890
15								
16	Adjustment to 13-month average		(311)	1,500	500	503	500	-
17	Unamortized Deferred Charges, Mid-Year	Schedule 9, Line 41	(0)	(2)	(4)	(7)	(11)	(15)
18	Cash Working Capital	[1]	(7)	(13)	(15)	(17)	(19)	(19)
19	**Total Rate Base**	**Sum of Lines 14 through 18**	**1,395**	**6,325**	**7,071**	**7,718**	**8,310**	**7,855**
20								
21	**Return on Rate Base**							
22	Equity Return	Line 19 x ROE x Equity %	53	213	238	260	280	265
23	Debt Component	[2]	56	247	273	287	283	272
24	Total Earned Return	Line 22 + Line 23	**109**	**460**	**511**	**547**	**563**	**536**
25	Return on Rate Base %	Line 24 / Line 19	7.82%	7.27%	7.22%	7.08%	6.77%	6.83%
26								
27	1- Schedule 7, Line 25 x FEI CWC/Closing GPIS %							
28	2- Line 19 x (LTD Rate x LTD% + STD Rate x STD %)							

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Capital Spending
Schedule 6
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	Capital Spending 2013 Onwards							
2	CNG Dispensing Equipment		2,563	2,197	732	732	732	-
3	Foundation		842	722	241	241	241	-
4	Natural Gas Dehydrator		95	82	27	27	27	-
5	Total Capital Spending 2013 Onwards	Sum of Lines 2 through 15	3,500	3,000	1,000	1,000	1,000	-
6								
7	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	3,500	3,000	1,000	1,000	1,000	-
8								
9	Contributions in Aid of Construction		-	-	-	-	-	-
10	Removal Costs		-	-	-	-	-	-
11	Net Annual Project Costs- Capital	Line 7 + 9 + 10	3,500	3,000	1,000	1,000	1,000	-
12								
13	Total Project Costs- Capital Spending and AFUDC	Sum of Line 7	**9,500**					
14	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 11	**9,500**					

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Gross Plant in Service & Contributions in Aid of Construction
Schedule 7
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Gross Plant in Service**							
2								
3	Gross Plant in Service, Beginning							
4	CNG Dispensing Equipment	Preceeding Year, Line 22	-	2,563	4,760	5,492	6,224	6,956
5	Foundation	Preceeding Year, Line 23	-	842	1,563	1,804	2,045	2,285
6	Natural Gas Dehydrator	Preceeding Year, Line 24	-	95	177	204	231	258
7	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 18	-	3,500	6,500	7,500	8,500	9,500
8								
9	Gross Plant in Service, Additions							
10	CNG Dispensing Equipment	Schedule 6, Lines 2 + 20 + 2 + 8	2,563	2,197	732	732	732	-
11	Foundation	Schedule 6, Lines 3 + 21 + 3 + 9	842	722	241	241	241	-
12	Natural Gas Dehydrator	Schedule 6, Lines 5 + 23 + 4 + 11	95	82	27	27	27	-
13	Total Gross Plant in Service, Additions	Sum of Lines 10 through 24	3,500	3,000	1,000	1,000	1,000	-
14								
15	Gross Plant in Service, Retirements							
16	CNG Dispensing Equipment		-	-	-	-	-	-
17	Foundation		-	-	-	-	-	-
18	Natural Gas Dehydrator		-	-	-	-	-	-
19	Total Gross Plant in Service, Retirements	Sum of Lines 16 through 30	-	-	-	-	-	-
20								
21	Gross Plant in Service, Ending							
22	CNG Dispensing Equipment	Line 4 + Line 10 + Line 16	2,563	4,760	5,492	6,224	6,956	6,956
23	Foundation	Line 5 + Line 11 + Line 17	842	1,563	1,804	2,045	2,285	2,285
24	Natural Gas Dehydrator	Line 6 + Line 12 + Line 18	95	177	204	231	258	258
25	Total Gross Plant in Service, Ending	Sum of Lines 22 through 36	3,500	6,500	7,500	8,500	9,500	9,500
26								
27								
28	**Contributions in Aid of Construction (CIAC)**							
29	CIAC, Beginning		-	-	-	-	-	-
30	Additions		-	-	-	-	-	-
31	Retirements		-	-	-	-	-	-
32	CIAC, Ending	Sum of Lines 29 through 31	-	-	-	-	-	-

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Accumulated Depreciation & Amortization
Schedule 8
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Accumulated Depreciation**							
2								
3	Accumulated Depreciation, Beginning							
4	CNG Dispensing Equipment	Preceeding Year, Line 22	-	(53)	(182)	(420)	(694)	(1,005)
5	Foundation	Preceeding Year, Line 23	-	(18)	(60)	(138)	(228)	(330)
6	Natural Gas Dehydrator	Preceeding Year, Line 24	-	(2)	(7)	(16)	(26)	(37)
7	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 18	-	(73)	(248)	(573)	(948)	(1,373)
8								
9	Accumulated Depreciation, Depreciation Expense[1]							
10	CNG Dispensing Equipment@ 5%	Schedule 7, Line 4 & Line 10	(53)	(128)	(238)	(275)	(311)	(348)
11	Foundation@ 5%	Schedule 7, Line 5 & Line 11	(18)	(42)	(78)	(90)	(102)	(114)
12	Natural Gas Dehydrator@ 5%	Schedule 7, Line 6 & Line 12	(2)	(5)	(9)	(10)	(12)	(13)
13	Total Accumulated Depreciation, Depreciation Expense	Sum of Lines 10 through 24	(73)	(175)	(325)	(375)	(425)	(475)
14								
15	Accumulated Depreciation, Retirements							
16	CNG Dispensing Equipment	Schedule 7, Line 16	-	-	-	-	-	-
17	Foundation	Schedule 7, Line 17	-	-	-	-	-	-
18	Natural Gas Dehydrator	Schedule 7, Line 18	-	-	-	-	-	-
19	Total Accumulated Depreciation, Retirements	Sum of Lines 16 through 30	-	-	-	-	-	-
20								
21	Accumulated Depreciation, Ending							
22	CNG Dispensing Equipment	Line 4 + Line 10 + Line 16	(53)	(182)	(420)	(694)	(1,005)	(1,353)
23	Foundation	Line 5 + Line 11 + Line 17	(18)	(60)	(138)	(228)	(330)	(444)
24	Natural Gas Dehydrator	Line 6 + Line 12 + Line 18	(2)	(7)	(16)	(26)	(37)	(50)
25	Total Accumulated Depreciation, Ending	Sum of Lines 22 through 36	(73)	(248)	(573)	(948)	(1,373)	(1,848)
26								
27								
28	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**							
29	Accumulated Amortization CIAC, Beginning		-	-	-	-	-	-
30	Amortization	[1]	-	-	-	-	-	-
31	Retirements		-	-	-	-	-	-
32	Accumulated Amortization CIAC, Ending	Sum of Lines 29 through 31	-	-	-	-	-	-
33								
34	1- Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/;							
35	otherwise, additions x 1/2). For 2014 forward, Depreciation & Amortization commences the year after the asset has been placed into service							

FortisBC Energy Inc.
GGRR CNG Fueling Station Class of Service

GGRR CNG Fueling Station Class of Service: Deferred Charges & Deficiency / Surplus [Tracker]
Schedule 9
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Deficiency / (Surplus) Tracker**							
2	Opening Balance	Previous Year, Line 10	-	86	124	115	101	59
3	Gross Addition	Schedule , Line 18 / 1000	86	33	(17)	(21)	(48)	(37)
4	Tax		-	-	-	-	-	-
5	Net Addition	Line 3 + Line 4	86	33	(17)	(21)	(48)	(37)
6	AFUDC							
7	Equity	Line 2 x (Schedule , Lines 7 x 8)	-	3	4	4	3	2
8	Debt	[1]	-	3	4	3	3	2
9	Interest Adjustment	[2]	-	-	-	-	-	-
10	Closing Balance	Sum of Lines 5 through 9	86	124	115	101	59	26
11								
12	**Deferred Charge- Negative Salvage Provision/Cost**							
13	Opening Balance	Previous Year, Line 19	-	(1)	(2)	(5)	(9)	(13)
14	Gross Additions		-	-	-	-	-	-
15	Tax	Line 14 x Tax Rate	-	-	-	-	-	-
16	Net Additions	Sum of Lines 14 through 15	-	-	-	-	-	-
17	Amortization Expense		(1)	(2)	(3)	(4)	(4)	(5)
18	Closing Balance	Lines 13 + 17 + 18	(1)	(2)	(5)	(9)	(13)	(18)
19								
20								
21	**Deferred Charge- Non Rate Base**							
22	Opening Balance	Previous Year, Line 30	-	86	124	115	101	59
23	Opening Balance, Adjustment	Opening balance transfer to rate base	-	-	-	-	-	-
24	Gross Additions		86	33	(17)	(21)	(48)	(37)
25	Tax		-	-	-	-	-	-
26	AFUDC		-	5	8	7	6	4
27	Net Additions	Sum of Lines 24 through 26	86	38	(9)	(14)	(42)	(33)
28	Interest Adjustment		-	-	-	-	-	-
29	Amortization Expense		-	-	-	-	-	-
30	Closing Balance	Lines 22 + 23 + 27 + 28 + 29	86	124	115	101	59	26
31								
32	**Deferred Charge- Rate Base**							
33	Opening Balance	Previous Year, Line 39	-	(1)	(2)	(5)	(9)	(13)
34	Opening Balance, Adjustment		-	-	-	-	-	-
35	Gross Additions		-	-	-	-	-	-
36	Tax		-	-	-	-	-	-
37	Net Additions		-	-	-	-	-	-
38	Amortization Expense		(1)	(2)	(3)	(4)	(4)	(5)
39	Closing Balance	Lines 33 + 37 + 38	(1)	(2)	(5)	(9)	(13)	(18)
40								
41	Deferred Charge, Mid-Year	(Line 33 + Line 34 + Line 39) / 2	(0)	(2)	(4)	(7)	(11)	(15)
42								
43	1- Line 2 x [Schedule , (Lines 10 x 11+ Lines 12 x 13) x (1- Tax Rate)]							
44	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract							

FortisBC Energy Inc.
GGRR LNG Fueling Station Class of Service

GGRR LNG Fueling Station Class of Service: Revenue Requirement
Schedule 10
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Revenue Requirement**							
2	Cost of Energy Sold		-	-	-	-	-	-
3	Operation and Maintenance	Schedule 11, Line 17	107	535	792	981	1,172	1,196
4	Property Taxes	Schedule 11, Line 22	-	25	34	43	52	53
5	Depreciation Expense	Schedule 17, Line 15 + Line 34	94	225	684	887	1,090	1,293
6	Amortization Expense	Schedule 18, Line 38	-	-	2	2	3	3
7	Other Revenue	Schedule 11, Line 22	-	-	-	-	-	-
8	Income Taxes	Schedule 12, Line 20	(71)	(275)	(311)	(274)	(228)	(104)
9	Earned Return	Schedule 14, Line 24	66	581	943	1,100	1,204	1,131
10								
11	**Annual Revenue Requirement**	Sum of Lines 2 through 9	**196**	**1,090**	**2,144**	**2,738**	**3,293**	**3,573**
12								
13	**Costs and (Recoveries) Transferred to Natural Gas Class of Service**							
14	OH&M Collected		(35)	(280)	(638)	(822)	(1,009)	(1,030)
15	Deficiency (Surplus) - as an add to FSVA deferral account		45	107	(20)	(6)	(36)	(100)

FortisBC Energy Inc.
GGRR LNG Fueling Station Class of Service

GGRR LNG Fueling Station Class of Service: O&M, Other Revenue and Property Tax
Schedule 11
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Gross O&M**							
2	Labour Costs		-	-	-	-	-	-
3	Vehicle Costs		-	-	-	-	-	-
4	Employee Expenses		-	-	-	-	-	-
5	Materials & Supplies		-	-	-	-	-	-
6	Computer Costs		-	-	-	-	-	-
7	Fees & Administrations Costs		-	-	-	-	-	-
8	Contractor Costs		104	528	783	969	1,159	1,183
9	Facilities		3	7	9	11	14	14
10	Recoveries & Revenue		-	-	-	-	-	-
11								
12	Non-Labour Costs		107	535	792	981	1,172	1,196
13								
14	Total Gross O&M Expenses		107	535	792	981	1,172	1,196
15								
16	(Less): Capitalized Overhead		-	-	-	-	-	-
17	Add (Less): Adjustment		-	-	-	-	-	-
17	Net O&M		107	535	792	981	1,172	1,196
18								
19	**Property Taxes**							
20	General, School and Other		-	25	34	43	52	53
21	1% in Lieu of General Municipal Tax[1]	Schedule , Line 42/1000 x 1%	-	-	-	-	-	-
22	Total Property Taxes		-	25	34	43	52	53
23								
24	1- Calculation is based on the second preceeding year; ex., 2012 is based on 2010 revenue							

GGRR LNG Fueling Station Class of Service: Income Tax Expense
Schedule 12
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Income Tax Expense**							
2								
3	Earned Return	Schedule 14, Line 24	66	581	943	1,100	1,204	1,131
4	Deduct: Interest on debt	Schedule 14, Line 23	(34)	(312)	(503)	(577)	(605)	(573)
5	Add (Deduct): Amortization Expense	Schedule 18, Line 38	-	-	-	-	-	-
6	Add: Depreciation Expense	Schedule 17, Line 15 + Line 34	94	225	684	887	1,090	1,293
7	Add: Removal Cost Provision	Schedule 18, Line 17	-	-	2	2	3	3
8	Deduct: Overhead Capitalized Expensed for Tax Purposes		-	-	-	-	-	-
9	Deduct Removal Costs	Schedule 18, Line 14	-	-	-	-	-	-
10	Deduct: Capital Cost Allowance	Schedule 13, Line 28	(338)	(1,318)	(2,058)	(2,233)	(2,374)	(2,166)
11	Taxable Income After Tax	Sum of Lines 3 through 10	(212)	(824)	(933)	(821)	(683)	(312)
12								
13	Income Tax Rate		25%	25%	25%	25%	25%	25%
14	1 - Current Income Tax Rate	1 - Line 13	75%	75%	75%	75%	75%	75%
15								
16	Taxable Income	Line 11 / Line 14	(282)	(1,099)	(1,243)	(1,095)	(911)	(416)
17								
18	Total Income Tax Expense	Line 16 x Line 13	(71)	(275)	(311)	(274)	(228)	(104)
19	Adjustments		-	-	-	-	-	-
20	Net Tax Expense	Line 18 + Line 19	(71)	(275)	(311)	(274)	(228)	(104)

GGRR LNG Fueling Station Class of Service: Capital Cost Allowance
Schedule 13
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**LNG Dispensing Equipment- Class 8 @ 20%**							
2	Opening Balance	Preceeding Year, Line 5	-	-	5,261	5,962	6,523	6,972
3	Additions	Schedule 16 , Line 11 - AFUDC	-	5,845	1,948	1,948	1,948	-
4	CCA	[Line 2 + (Line 3 x 1/2)] x CCA Rate	-	(585)	(1,247)	(1,387)	(1,500)	(1,394)
5	Closing Balance	Sum of Lines 2 through 4	-	5,261	5,962	6,523	6,972	5,578
6								
7	**Foundation- Class 1 @ 4%**							
8	Opening Balance	Preceeding Year, Line 11	-	-	1,448	1,873	2,281	2,672
9	Additions	Schedule 16 , Line 12 - AFUDC	-	1,478	493	493	493	-
10	CCA	[Line 8 + (Line 9 x 1/2)] x CCA Rate	-	(30)	(68)	(85)	(101)	(107)
11	Closing Balance	Sum of Lines 8 through 10	-	1,448	1,873	2,281	2,672	2,565
12								
13	**LNG Dispensing Equipment - Mobile- Class 10 @ 30%**							
14	Opening Balance	Preceeding Year, Line 17	-	1,913	1,976	2,021	2,052	2,074
15	Additions	Schedule 16 , Line 13 - AFUDC	2,250	750	750	750	750	-
16	CCA	[Line 14 + (Line 15 x 1/2)] x CCA Rate	(338)	(686)	(705)	(719)	(728)	(622)
17	Closing Balance	Sum of Lines 14 through 16	1,913	1,976	2,021	2,052	2,074	1,452
18								
19	**Pumps- Class 8 @ 20%**							
20	Opening Balance	Preceeding Year, Line 23	-	-	159	180	197	211
21	Additions	Schedule 16 , Line 14 - AFUDC	-	177	59	59	59	-
22	CCA	[Line 20 + (Line 21 x 1/2)] x CCA Rate	-	(18)	(38)	(42)	(45)	(42)
23	Closing Balance	Sum of Lines 20 through 22	-	159	180	197	211	169
24								
25	**Total CCA**							
26	Opening Balance	Preceeding Year, Line 29	-	1,913	8,844	10,037	11,054	11,930
27	Additions	[1]	2,250	8,250	3,250	3,250	3,250	-
28	CCA	[2]	(338)	(1,318)	(2,058)	(2,233)	(2,374)	(2,166)
29	Closing Balance	Sum of Lines 26 through 28	1,913	8,844	10,037	11,054	11,930	9,764
30	1- Schedule 16 , Line 15 - Line 26 + Line 93 above - AFUDC							
31	2- Schedule 13 , Sum of detailed CCA lines							

FortisBC Energy Inc.
GGRR LNG Fueling Station Class of Service

GGRR LNG Fueling Station Class of Service: Rate Base
Schedule 14
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Rate Base**							
2	Gross Plant In Service- Beginning	Schedule 16, Line 8	-	2,250	10,500	13,750	17,000	20,250
3	Gross Plant In Service- Ending	Schedule 16, Line 29	2,250	10,500	13,750	17,000	20,250	20,250
4								
5	Accumulated Depreciation- Beginning	Schedule 17, Line 8	-	(94)	(319)	(1,003)	(1,889)	(2,979)
6	Accumulated Depreciation- Ending	Schedule 17, Line 29	(94)	(319)	(1,003)	(1,889)	(2,979)	(4,272)
7								
8	Contributions in Aid of Construction- Beginning	Schedule 16, Line 33	-	-	-	-	-	-
9	Contributions in Aid of Construction- Ending	Schedule 16, Line 36	-	-	-	-	-	-
10								
11	Accumulated Amortization- Beginning	Schedule 17, Line 33	-	-	-	-	-	-
12	Accumulated Amortization- Ending	Schedule 17, Line 36	-	-	-	-	-	-
13								
14	Net Plant in Service, Mid-Year	Sum (Lines 2 through 12)/2	1,078	6,169	11,464	13,929	16,191	16,625
15								
16	Adjustment to 13-month average		(233)	1,837	1,625	1,634	1,625	-
17	Unamortized Deferred Charges, Mid-Year	Schedule 18, Line 41	-	-	(1)	(3)	(5)	(8)
18	Cash Working Capital	[1]	(5)	(21)	(28)	(34)	(41)	(41)
19	**Total Rate Base**	**Sum of Lines 14 through 18**	**840**	**7,985**	**13,061**	**15,526**	**17,770**	**16,577**
20								
21	**Return on Rate Base**							
22	Equity Return	Line 19 x ROE x Equity %	32	269	440	523	599	558
23	Debt Component	[2]	34	312	503	577	605	573
24	Total Earned Return	Line 22 + Line 23	**66**	**581**	**943**	**1,100**	**1,204**	**1,131**
25	Return on Rate Base %	Line 24 / Line 19	7.82%	7.27%	7.22%	7.08%	6.77%	6.83%
26								
27	1- Schedule 16, Line 29 x FEI CWC/Closing GPIS %							
28	2- Line 19 x (LTD Rate x LTD% + STD Rate x STD %)							

FortisBC Energy Inc.
GGRR LNG Fueling Station Class of Service

GGRR LNG Fueling Station Class of Service: Capital Spending
Schedule 15
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	Capital Spending 2013 Onwards							
2	LNG Dispensing Equipment		-	5,845	1,948	1,948	1,948	-
3	Foundation		-	1,478	493	493	493	-
4	LNG Dispensing Equipment - Mobile		2,250	750	750	750	750	-
4	Pumps		-	177	59	59	59	-
5	Total Capital Spending 2013 Onwards	Sum of Lines 2 through 15	2,250	8,250	3,250	3,250	3,250	-
6								
7	Total Annual Capital Spending and AFUDC	Line 25 + Line 26	2,250	8,250	3,250	3,250	3,250	-
8								
9	Contributions in Aid of Construction		-	-	-	-	-	-
10	Removal Costs		-	-	-	-	-	-
11	Net Annual Project Costs- Capital	Line 7 + 9 + 10	2,250	8,250	3,250	3,250	3,250	-
12								
13	Total Project Costs- Capital Spending and AFUDC	Sum of Line 7	**20,250**					
14	Total Net Project Costs- including CIAC & Removal Costs	Sum of Line 11	**20,250**					

FortisBC Energy Inc.
GGRR LNG Fueling Station Class of Service

GGRR LNG Fueling Station Class of Service: Gross Plant in Service & Contributions in Aid of Construction
Schedule 16
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Gross Plant in Service**							
2								
3	Gross Plant in Service, Beginning							
4	LNG Dispensing Equipment	Preceeding Year, Line 25	-	-	5,845	7,794	9,742	11,691
5	Foundation	Preceeding Year, Line 26	-	-	1,478	1,970	2,463	2,955
6	LNG Dispensing Equipment - Mobile	Preceeding Year, Line 27	-	2,250	3,000	3,750	4,500	5,250
7	Pumps	Preceeding Year, Line 28	-	-	177	236	295	354
8	Total Gross Plant in Service, Beginning	Sum of Lines 4 through 19	-	2,250	10,500	13,750	17,000	20,250
9								
10	Gross Plant in Service, Additions							
11	LNG Dispensing Equipment	Schedule 15, Lines 2 + 20 + 2 + 8	-	5,845	1,948	1,948	1,948	-
12	Foundation	Schedule 15, Lines 3 + 21 + 3 + 9	-	1,478	493	493	493	-
13	LNG Dispensing Equipment - Mobile	Schedule 15, Lines 4 + 22 + 4 + 10	2,250	750	750	750	750	-
14	Pumps	Schedule 15, Lines 5 + 23 + 4 + 11	-	177	59	59	59	-
15	Total Gross Plant in Service, Additions	Sum of Lines 11 through 26	2,250	8,250	3,250	3,250	3,250	-
16								
17	Gross Plant in Service, Retirements							
18	LNG Dispensing Equipment		-	-	-	-	-	-
19	Foundation		-	-	-	-	-	-
20	LNG Dispensing Equipment - Mobile		-	-	-	-	-	-
21	Pumps		-	-	-	-	-	-
22	Total Gross Plant in Service, Retirements	Sum of Lines 18 through 33	-	-	-	-	-	-
23								
24	Gross Plant in Service, Ending							
25	LNG Dispensing Equipment	Line 4 + Line 11 + Line 18	-	5,845	7,794	9,742	11,691	11,691
26	Foundation	Line 5 + Line 12 + Line 19	-	1,478	1,970	2,463	2,955	2,955
27	LNG Dispensing Equipment - Mobile	Line 6 + Line 13 + Line 20	2,250	3,000	3,750	4,500	5,250	5,250
28	Pumps	Line 7 + Line 14 + Line 21	-	177	236	295	354	354
29	Total Gross Plant in Service, Ending	Sum of Lines 25 through 40	2,250	10,500	13,750	17,000	20,250	20,250
30								
31								
32	**Contributions in Aid of Construction (CIAC)**							
33	CIAC, Beginning		-	-	-	-	-	-
34	Additions		-	-	-	-	-	-
35	Retirements		-	-	-	-	-	-
36	CIAC, Ending	Sum of Lines 33 through 35	-	-	-	-	-	-

FortisBC Energy Inc.
GGRR LNG Fueling Station Class of Service

GGRR LNG Fueling Station Class of Service: Accumulated Depreciation & Amortization
Schedule 17
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Accumulated Depreciation**							
2								
3	Accumulated Depreciation, Beginning							
4	LNG Dispensing Equipment	Preceeding Year, Line 25	-	-	-	(292)	(682)	(1,169)
5	Foundation	Preceeding Year, Line 26	-	-	-	(74)	(172)	(296)
6	LNG Dispensing Equipment - Mobile	Preceeding Year, Line 27	-	(94)	(319)	(619)	(994)	(1,444)
7	Pumps	Preceeding Year, Line 28	-	-	-	(18)	(41)	(71)
8	Total Accumulated Depreciation, Beginning	Sum of Lines 4 through 19	-	(94)	(319)	(1,003)	(1,889)	(2,979)
9								
10	Accumulated Depreciation, Depreciation Expense[1]							
11	LNG Dispensing Equipment@ 5%	Schedule 16, Line 4 & Line 11	-	-	(292)	(390)	(487)	(585)
12	Foundation@ 5%	Schedule 16, Line 5 & Line 12	-	-	(74)	(99)	(123)	(148)
13	LNG Dispensing Equipment - Mobile@ 10%	Schedule 16, Line 6 & Line 13	(94)	(225)	(300)	(375)	(450)	(525)
14	Pumps@ 10%	Schedule 16, Line 7 & Line 14	-	-	(18)	(24)	(29)	(35)
15	Total Accumulated Depreciation, Depreciation Expense	Sum of Lines 11 through 26	(94)	(225)	(684)	(887)	(1,090)	(1,293)
16								
17	Accumulated Depreciation, Retirements							
18	LNG Dispensing Equipment	Schedule 16, Line 18	-	-	-	-	-	-
19	Foundation	Schedule 16, Line 19	-	-	-	-	-	-
20	LNG Dispensing Equipment - Mobile	Schedule 16, Line 20	-	-	-	-	-	-
21	Pumps	Schedule 16, Line 21	-	-	-	-	-	-
22	Total Accumulated Depreciation, Retirements	Sum of Lines 18 through 33	-	-	-	-	-	-
23								
24	Accumulated Depreciation, Ending							
25	LNG Dispensing Equipment	Line 4 + Line 11 + Line 18	-	-	(292)	(682)	(1,169)	(1,754)
26	Foundation	Line 5 + Line 12 + Line 19	-	-	(74)	(172)	(296)	(443)
27	LNG Dispensing Equipment - Mobile	Line 6 + Line 13 + Line 20	(94)	(319)	(619)	(994)	(1,444)	(1,969)
28	Pumps	Line 7 + Line 14 + Line 21	-	-	(18)	(41)	(71)	(106)
29	Total Accumulated Depreciation, Ending	Sum of Lines 25 through 40	(94)	(319)	(1,003)	(1,889)	(2,979)	(4,272)
30								
31								
32	**Accumulated Amortization of Contributions in Aid of Construction (CIAC)**							
33	Accumulated Amortization CIAC, Beginning		-	-	-	-	-	-
34	Amortization	1	-	-	-	-	-	-
35	Retirements		-	-	-	-	-	-
36	Accumulated Amortization CIAC, Ending	Sum of Lines 33 through 35	-	-	-	-	-	-
37								

38 1- For 2013, Depreciation & Amortization Expense calculation is based on opening balance + (additions x in-service days/365 if it is the in-service year for project/;
39 otherwise, additions x 1/2). For 2014 forward, Depreciation & Amortization commences the year after the asset has been placed into service

GGRR LNG Fueling Station Class of Service: Deferred Charges & Deficiency / Surplus [Tracker]
Schedule 18
($000's), unless otherwise stated

Line	Particulars	Reference	2013	2014	2015	2016	2017	2018
1	**Deficiency / (Surplus) Tracker**							
2	Opening Balance	Previous Year, Line 10	-	45	154	144	147	120
3	Gross Addition		45	107	(20)	(6)	(36)	(100)
4	Tax		-	-	-	-	-	-
5	Net Addition	Line 3 + Line 4	45	107	(20)	(6)	(36)	(100)
6	AFUDC							
7	Equity	Line 2 x (Schedule , Lines 7 x 8)	-	2	5	5	5	4
8	Debt	[1]	-	1	4	4	4	3
9	Interest Adjustment	[2]	-	-	-	-	-	-
10	Closing Balance	Sum of Lines 5 through 9	45	154	144	147	120	27
11								
12	**Deferred Charge- Negative Salvage Provision/Cost**							
13	Opening Balance	Previous Year, Line 19	-	-	-	(2)	(4)	(6)
14	Gross Additions		-	-	-	-	-	-
15	Tax	Line 14 x Tax Rate	-	-	-	-	-	-
16	Net Additions	Sum of Lines 14 through 15	-	-	-	-	-	-
17	Amortization Expense		-	-	(2)	(2)	(3)	(3)
18	Closing Balance	Lines 13 + 17 + 18	-	-	(2)	(4)	(6)	(9)
19								
20								
21	**Deferred Charge- Non Rate Base**							
22	Opening Balance	Previous Year, Line 30	-	45	154	144	147	120
23	Opening Balance, Adjustment	Opening balance transfer to rate base	-	-	-	-	-	-
24	Gross Additions		45	107	(20)	(6)	(36)	(100)
25	Tax		-	-	-	-	-	-
26	AFUDC		-	3	10	9	9	7
27	Net Additions	Sum of Lines 24 through 26	45	110	(10)	3	(27)	(93)
28	Interest Adjustment		-	-	-	-	-	-
29	Amortization Expense		-	-	-	-	-	-
30	Closing Balance	Lines 22 + 23 + 27 + 28 + 29	45	154	144	147	120	27
31								
32	**Deferred Charge- Rate Base**							
33	Opening Balance	Previous Year, Line 39	-	-	-	(2)	(4)	(6)
34	Opening Balance, Adjustment		-	-	-	-	-	-
35	Gross Additions		-	-	-	-	-	-
36	Tax		-	-	-	-	-	-
37	Net Additions		-	-	-	-	-	-
38	Amortization Expense		-	-	(2)	(2)	(3)	(3)
39	Closing Balance	Lines 33 + 37 + 38	-	-	(2)	(4)	(6)	(9)
40								
41	Deferred Charge, Mid-Year	(Line 33 + Line 34 + Line 39) / 2	-	-	(1)	(3)	(5)	(8)
42								
43	1- Line 2 x [Schedule , (Lines 10 x 11+ Lines 12 x 13) x (1- Tax Rate)]							
44	2- Adjustment to net account to zero in final year; result of varying WACC rates throughout contract							

Appendix I

ENERGY EFFICIENCY AND CONSERVATION & DEMAND SIDE MANAGEMENT

Energy Efficiency and Conservation

and

Demand Side Management

May 2013

Table of Contents

1. INTRODUCTION

This Appendix outlines the FEU's requests pursuant to section 44.2 of the Utilities Commission Act (UCA) for acceptance of EEC expenditures for the period from 2014 to 2018. The funding request outlined in this Appendix is supported by the 2014-2018 EEC Plan which is included as Attachment I1. The 2014-2018 EEC Plan provides details on each of the FEU's program areas and individual EEC programs, including cost-effectiveness test results. The FEU's funding request is also supported by the FEU's 2012 EEC Annual Report included as Attachment I2. The 2012 EEC Annual Report describes the results of the FEU's 2012 EEC programs, most of which the FEU are proposing to continue. In sum, the FEU's evidence in this Application demonstrates that the proposed EEC expenditures are cost effective and in the public interest.

The FEU are seeking acceptance under section 44.2 of the UCA of EEC expenditures for FEI, FEVI, and FEW. The FEU will allocate both incentive and non-incentive expenditures to FEI and FEVI on an as-incurred basis in accordance with the service area in which the customers receiving the incentives are located, and will allocate 1 percent to FEW reflecting the proportion of total FEU customers served by FEW. This approach is consistent with the approval of the FEU's 2012-2013 EEC expenditures in Order G-44-12. While FEI will incorporate the accepted EEC costs into rates through this Application, FEVI and FEW will incorporate the accepted EEC expenditures into rates in their respective RRAs, which are expected to be filed later this year.

The sections in this Appendix are outlined below:

- 1: Introduction
- 2: Background
  - 2.1: Legal Framework
  - 2.2: Consistency with British Columbia Energy Objectives
  - 2.3: Consistency with Long Term Resource Plan
  - 2.4: Adequacy Pursuant to the DSM Regulation
  - 2.5: Interests of Persons Who May Receive Service
- 3: Response to Commission Directives
- 4: Historical Expenditures and Success of Program to Date
- 5: EEC Plan and Funding Request
  - 5.1: Funding Request by Program Area
  - 5.2: New and Previously Approved Programs
  - 5.3: Plan Flexibility and Adjustment

Attachments:

2. BACKGROUND

2.1 *LEGAL FRAMEWORK*

The FEU are filing their EEC requests pursuant to section 44.2(1)(a) of the UCA, which provides that a utility may file "a statement of the expenditures on demand-side measure the public utility has made or anticipates making during the period addressed by the utility." As shown in the EEC Plan (Attachment I1), all proposed activity qualifies as "demand side measures" as defined under the UCA. Section 44.2(2) of the UCA provides that the Commission must accept an expenditure schedule of demand-side measure expenditures before including those expenditures in rates.

Pursuant to section 44.2(3) and (4), the Commission must accept the expenditure schedule if it considers the schedule to be in the public interest, or it may accept a part of the schedule. In considering whether a demand-side measure expenditure schedule put forward by a non-crown public utility is in the public interest, the Commission must consider the following criteria according to section 44.2(5):

- the applicable of British Columbia's energy objectives,
- the most recent long-term resource plan filed by the public utility under section 44.1, if any,
- 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
- the interests of persons in British Columbia who receive or may receive service from the public utility.

These four required considerations are addressed in sections 2.2, 2.3 and 2.5, respectively. The consideration of "adequacy" as defined in the Demand Side Measures Regulation is discussed in Section 2.4 below.

2.2 *CONSISTENCY WITH BRITISH COLUMBIA ENERGY OBJECTIVES*

British Columbia's energy objectives are defined and set out in section 2 of the *Clean Energy Act*. The applicable energy objectives and how the FEU's proposals support those objectives are set out in the table below.

1 **Table I-1: BC's Energy Objectives Met by FEU EEC Activity**

Energy Objective	FEU EEC Portfolio
(b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;	The FEU's EEC proposals are designed to implement all cost-effective (as defined by the Demand Side Measures Regulation) demand-side measures. The estimated net present value of natural gas savings (net of free ridership) for the 2014 to 2018 period is projected to be a total of 23,503,471 million GJs.
(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;	The FEU have an Innovative Technologies Program Area, described in Section 8 of Attachment I1 designed to meet this objective.
(g) to reduce BC greenhouse gas emissions (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007, (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007, (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007, (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and (v) by such other amounts as determined under the Greenhouse Gas Reduction Targets Act;	The FEU's EEC programs will result in substantial natural gas savings. This will in turn lead to commensurate reductions in greenhouse gas emissions of 1,198,677 CO2e.
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;	The FEU's high carbon fuel switching program, although not part of the 2014-2018 EEC Plan, and included instead in O&M expenditure and described in (O&M Energy Solutions & External Relations Section C3.6), fosters this objective by encouraging the switching from higher carbon oil and propane heating systems to natural gas using high efficiency furnaces, resulting in a reduction in greenhouse gas emissions.
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;	All of the FEU's EEC programs meet the objective of encouraging communities to reduce greenhouse gas emissions and use energy efficiently.

Energy Objective	FEU EEC Portfolio
(k) to encourage economic development and the creation and retention of jobs;	The FEU's EEC Programs also have a broad impact on the provincial economy as measured through employment, GDP and industrial output. The 2010 Conservation Potential Review (CPR) provides a summary of the significant potential economic impact of the FEU's EEC activities.[1] Based on this report, by 2021, the net employment gains from activities listed in the CPR will range between 5.8 – 6.7 jobs per $1 million invested in DSM that year. Also by 2021, the impact per $1 million spent on DSM will range from about $900,000 to $985,000 for output and $315,000 to $350,000 for GDP.

In the FEU's view, the Commission's consideration of British Columbia's energy objectives must weigh heavily in favour of the FEU's proposals to continue investment in cost-effective EEC programs.

2.3 CONSISTENCY WITH LONG TERM RESOURCE PLAN

Under section 44.2 of the UCA, the Commission, in considering whether to accept an expenditure schedule by a utility, must consider that utility's most recent long-term resource plan filed under section 44.1 of the Act. The current Long Term Resource Plan (LTRP) as accepted by the Commission is the 2010 LTRP, submitted in July of that year.[2] The FEU's 2014-2018 EEC Plan and the proposed expenditures are consistent with the 2010 LTRP, and the directives that the Commission made within its decision to accept that plan.[3]

The 2010 LTRP examined the impact of three potential EEC expenditure levels on the amount of natural gas and GHG emission savings that Companies could achieve over the 20-year LTRP planning horizon. The Companies recommended a higher level of funding[4] than had been implemented in prior years, and from that recommendation developed a funding level request of $74.5 million for each of 2012 and 2013 within its next RRA. This request was subsequently amended to $64.5 million, to remove funding for natural gas vehicle related incentives, for each 2012 and 2013 following the release of the EEC NGV Incentives Decision.[5] The LTRP also

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1 FEU 2012-2013 RRA, Exhibit B-1, Appendix K-2, Conservation Potential Review, p. 41 to 42. The full CPR, including the full study regarding the impact on the economy, is provided in Exhibit B-9-1, Attachment 196.1.

2 Submitted by Terasen Utilities (Terasen Gas Inc., Terasen Gas (Whistler) Inc. and Terasen Gas (Vancouver Island) Inc.)

3 BCUC Order G-14-11.

4 The 2010 LTRP recommended that EEC funding set at 5 percent of the Terasen Utilities' annual revenues, which would equate to ~$80 million in 2012 including funding for natural gas vehicle incentives, which would make a significant contribution to energy savings and GHG emission reductions. This represented funding of slightly more than twice the previously-approved funding levels, and included NGV initiatives.

5 In the Matter of FortisBC Energy Inc. and Fortis BC (Vancouver Island) Inc. Energy Efficiency and Conservation Program Natural Gas Incentives Review; Decision and Order G-145-11 dated August 15, 2011 (EEC NGV Incentives Review Decision).

stated that the Companies would be completing a new CPR that would help guide the development and growth of EEC programs going forward. The CPR was subsequently completed, forming the basis of the Companies' 2012 and 2013 EEC funding request.

The Commission was satisfied at the time the LTRP was reviewed that the FEU intended to pursue adequate, cost-effective demand side measures (DSM). The expenditure schedule requested for the 2014-2018 test period, averaging $37,132,000 per year (including inflation) and the type of EEC programming anticipated remain consistent with that of the current EEC funding envelope and 2012-2013 EEC Plan. This was found to be consistent with the 2010 LTRP and is also aligned with the 2013 LTRP, currently under development.

2.4 *ADEQUACY PURSUANT TO THE DSM REGULATION*

A public utility's plan portfolio is adequate for the purposes of Section 44.1 (8) (c) of the UCA regarding long-term resource plans, only if the plan portfolio includes all of the following, as set out in Section 3 of the DSM Regulation:

a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

b) if the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

c) an education program for students enrolled in schools in the public utility's service area;

d) if the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area.

While these requirements are applicable to long-term resource plans, since they are related to the demand-side measures, the FEU address each of these considerations below.

2.4.1 Low Income Programs

The Low Income Program Area is specifically designed to meet the needs of the Companies' low income customers. One of the EEC principles is that "programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income customers." The Companies are staying true to this principle by developing and implementing programs that are of no cost or low cost to low income participants.

Our goal of creating programs that are accessible to all has been achieved through the launch of our Energy Saving Kit (ESK) Program, the Residential Energy Efficiency Works (REnEW) Program, and the new Energy Conservation Assistance Program (ECAP). Continued investment in this Program Area, along with increased savings for low income customers, is planned moving forward. Three additional programs have been proposed for 2014-2018: the

Low Income Space Heat Top-Ups, Low Income Water Heating Top-Ups and Non-Profit Custom Program.

2.4.2 Rental Accommodations

All programs in the Residential Energy Efficiency Program Area are available to rental properties.

Some of the programs included in the Commercial Energy Efficiency Program Area are also available for use by, and actively promoted to, owners of rental accommodations. These include the Space Heat Program, the Water Heating Program and the Commercial Energy Assessment Program.

2.4.3 Education Programs

The FEU fund a variety of education programs for K-12 students enrolled in schools in its service areas through Conservation Education and Outreach (CEO) initiatives. Activities include building partnerships and providing funding support for a variety of in-class and online programs related to conserving energy for K-12 students. These programs are delivered both internally and by external third parties such as non-profit organizations or local sports teams. Examples of in-school and student programs include Energy is Awesome, Destination Conservation, BC Green Games, Green Bricks, Energy Champion assembly presentations, Vancouver Aquarium Aquaguide and Beyond Recycling.

There are also a number of initiatives specifically targeting post-secondary students, encouraging them to learn and apply their knowledge of natural gas energy conservation through interactive and fun competitions. Examples include encouraging campus residents to take shorter showers and 'Shut the Sash' campaigns on chemistry lab fume hoods.

2.5 *INTERESTS OF PERSONS WHO MAY RECEIVE SERVICE*

Taking all the evidence into account, the FEU believe that the proposed EEC expenditures are in the interests of customers and potential customers as they encourage energy efficiency and conservation, reduce GHG emissions, are beneficial to the economy and are cost-effective. Individual customers that avail themselves of EEC measures will reduce their natural gas consumption and, all else equal, their natural gas bills.

3. RESPONSE TO COMMISSION DIRECTIVES

The Companies believe that they have met the directives listed in the 2012-2013 RRA Decision and the AES Inquiry Report related to the FEU's EEC expenditures. Table I-2 addresses each of the directives related to EEC and briefly describes how the Companies have complied with these directives including references to where further information on this compliance can be sourced. The first sixteen rows in the table below address the 2012-2013 RRA Decision directives as listed in Appendix A to Order G-44-12 that are relevant to EEC expenditures and the 17th row addresses the EEC directive that came out of the AES Inquiry Report.

1 **Table I-2: FEU Meets Commission Directives**

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 66 and Directive 81, 2012-2013 RRA Decision	To assist in understanding how best to amortize EEC expenditures and over what term, the FEU are directed to provide a report detailing the rate impact of a number of amortization scenarios which will be helpful in determining a long term solution. For the 2012/2013 test period, the Commission Panel is satisfied that the proposed 10-year amortization period for the rate base deferral account is reasonable as is the FEU's proposal to allocate costs based upon the average number of customers served by each Company. Accordingly, the Commission Panel approves the following: 1. EEC rate base additions of $15 million in both 2012 and 2013 to be included on a net-of-tax basis and amortized in rates over a 10-year period. 2. The allocation of the 2012 and 2013 EEC rate base deferral account non-incentive additions amongst Mainland, Vancouver Island and Whistler on an average customer basis which is approximately 89 percent to Mainland, 10 percent to Vancouver Island and 1 percent to Whistler. 3. The allocation of 2012 and 2013 EEC incentive costs on an as incurred basis. 4. The creation of an EEC Non-Rate Base deferral account, attracting AFUDC, to capture the additional EEC costs as incurred on an actual spend basis to a maximum of the total approved EEC expenditures less $15 million in 2012 and 2013. No determination on amortization rates will be made at this time.	Rate base additions and allocations have been applied as outlined in the directive. See last directive in this table below regarding report related to amortization	Section D4 and Appendix F4 and F-5 of this application. Attachment I2: 2012 EEC Annual Report, Section 2.1.

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 67, 2012-2013 RRA Decision	The Commission Panel directs the FEU to take greater advantage of opportunities to collaborate with other utilities with respect to CEO campaigns and communications. In pursuing a more collaborative approach to these types of programs, we believe that there will be savings and available funds can be more effectively used. Accordingly, the Commission Panel approves a reduced amount totalling $2.9 million for both 2012 and 2013 for Existing CEO programs which are currently active.	A key development in the CEO Program Area in 2012 were the growing partnerships with FortisBC Inc. electric utility and BC Hydro in an effort to maximize cost effectiveness and efficiency. In partnership with FortisBC Inc. This included cost sharing on print communications, booth displays and production items for various events and campaigns occurring in the shared service territory. In addition, steps were also taken toward increasing collaboration with BC Hydro in sharing best practices on partnership negotiations and outreach tactics and will be collaborating on 6 outreach events in 2013.	Attachment I2: 2012 EEC Annual Report, Section 10.
Directive 68, 2012-2013 RRA Decision	The Commission Panel approves the requested expenditures of $18.209 million in 2012 and $18.206 million in 2013 for Existing Program Areas (excepting CEO Programs) which are currently active.	The Companies have spent within the expenditure limits.	Attachment I2: 2012 EEC Annual Report.

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 69, 2012-2013 RRA Decision	The Commission Panel approves 40 percent or $6.598 million of the requested expenditures for new programs in Existing Program Areas in 2012 and 80 percent or $13.098 million of requested expenditures for 2013.	The Companies have spent within the expenditure limits.	Attachment I2: 2012 EEC Annual Report.
Directive 70, 2012-2013 RRA Decision	The Commission Panel rejects the expenditures proposed for the Solar Thermal Program Area and the Thermal Energy for Schools Program Area. The Commission Panel also rejects the expenditure of $10 million annually for the Furnace Scrap-it program[6] in 2012 and 2013. However, the Commission Panel believes that the Furnace Scrap-it Program has potential and approves expenditures of $2 million for each of 2012 and 2013 for the Furnace Scrap-it program. Part of the $2 million in approved funds is to be used during the test period to develop a comprehensive program plan. The Commission Panel directs the FEU to include the Furnace Scrap-it program under its Residential Program Area.	The Solar Thermal and Thermal Energy for Schools Program Areas were not developed. A Furnace Scrap-It pilot program was executed in 2012 under the guidelines listed in this directive and included in the Residential Program Area.	Attachment I2: 2012 EEC Annual Report, p. 32. Attachment I5: Furnace Replacement Pilot and Program.

[6] The “Furnace Scrap-It Program” was renamed the “Furnace Replacement Pilot and Program” prior to the launch of the first iteration of the Furnace Replacement Pilot in September 2012.

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 71, 2012-2013 RRA Decision	The Commission Panel believes the requests of the FEU are reasonable and approves the request to expand EEC program eligibility to interruptible industrial, FortisBC Energy (Whistler) Inc. and FortisBC Energy Inc. Fort Nelson Service Area customers.	EEC program eligibility was expanded to include interruptible industrial, FEW and FEI Fort Nelson Service Area customers.	Attachment I2: 2012 EEC Annual Report includes FEW and Industrial Program activity reporting. FEFN activity is captured in FEI Program reporting.
Directive 72, 2012-2013 RRA Decision	The Commission Panel makes no determination on the inclusion of spillover in this RRA. The FEU may readdress this issue in future applications.	Spillover has not been reported as a metric to assess program results to date. In this RRA, the FEU seek the Commission's endorsement of the appropriateness of recognizing "spillover" effects in the NTG ratio on a case-by-case basis.	Appendix I: Section 6.2.1.

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 73, 2012-2013 RRA Decision	The Commission approves the movement of funding to a maximum of 25 percent from one approved Program Area to another approved Program Area without prior approval of the Commission. In cases where a proposed transfer into an approved Program Area is greater than 25 percent of that approved Program Area, prior Commission approval is required. Finally, the transfer of funds to new programs, not approved in this Application, or to Innovative Technologies (see below) will require prior Commission approval.	The Companies have incurred only one funding transfer between Program Areas. This occurred in 2012 and is described in the 2012 EEC Annual Report. A funding transfer of $2.0 million was made in 2012 from the Commercial Energy Efficiency Program Area to the Residential Energy Efficiency Program Area.	Attachment I2: 2012 EEC Annual Report, Section 3.
Directive 74, 2012-2013 RRA Decision	The Commission approves the assessment of cost effectiveness on an overall portfolio basis, subject to further determinations regarding the Innovative Technologies Program Area discussed below.	Cost effectiveness has been reported on an overall portfolio basis.	Attachment I2: 2012 EEC Annual Report, p. 9.
Directive 75, 2012-2013 RRA Decision	The Commission Panel lifts the requirement for the Innovative Technologies Program Area to be evaluated as a separate segment of the EEC portfolio meeting TRC of 1 or greater as agreed to in the NSA for the 2010 and 2011 RRA. However, the Panel further determines that these programs need not meet the new MTRC test. The expenditures in this Innovative Technologies Program Area are subject to the portfolio level cost-effectiveness testing discussed above and are subject to the 33 percent cap for expenditures that do not pass the MTRC test as written in the DSM Regulation as discussed in Section 8.2. However, because these technologies may fall into the category of activities being dealt with by the AES Inquiry, the Panel directs that transfers of funds into or out of this program area are not to occur without prior Commission approval.	The Innovative Technologies Program Area has been treated as outlined in this decision. No funding transfers have been requested for this program area.	Attachment I2: 2012 EEC Annual Report, Section 8.

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 76, 2012-2013 RRA Decision	The Commission Panel directs the FEU to develop a Terms of Reference in consultation with the Stakeholder Group. The Commission further directs the FEU to continue filing an Annual Report to the Commission but to add to this report a section detailing the EEC Stakeholder Group's views with attention to items such as funding transfers, new programs and any other material the Stakeholder Group deems appropriate and wishes to provide.	Terms of Reference has been developed in consultation with the Stakeholder Group. A summary of the EEC Advisory Group activities has been included in the 2012 EEC Annual Report.	Attachment I2: 2012 EEC Annual Report, Section 4.3.1.
Directive 77, 2012-2013 RRA Decision	The Commission Panel directs the FEU not to reinstate programs or Program Areas that have previously been rejected without approval of the Commission. When a program or Program Area has been rejected, the Commission directs the FEU to apply to the Commission for approval prior to spending EEC funds on that program or Program Area.	No previously rejected programs have been reinstated or requested for reinstatement.	Attachment I2: 2012 EEC Annual Report.
Directive 78, 2012-2013 RRA Decision	The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework.	The FEU has developed an evaluation plan and presented an EM&V Framework to the EEC Advisory Group.	Attachment I2: 2012 EEC Annual Report, Section 12.1 Appendix I: 7.1 & 7.2
Directive 79, 2012-2013 RRA Decision	The Commission Panel directs the FEU to develop attribution rules for all integrated programs which prevent the double counting of savings.	Discussions with partner utilities on attribution rules initiated for completion in 2013.	Appendix I: Section 7.3
Directive 80, 2012-2013 RRA Decision	The Commission directs the FEU to hold all EEC incentives that are provided for AES or TES technologies for projects in which the Companies are a participant in a separate deferral account. The recovery of this deferral account will be left to the Panel which hears the next FEU revenue requirements application. That Panel will have a benefit of the Panel's decision in the AES Inquiry.	EEC incentives provided for TES projects are held in a separate deferral account.	Attachment I2: 2012 EEC Annual Report, Section 2.4; Appendix F5.

Directive Reference (s)	Commission Directives to EEC	Compliance Undertaken	Response Reference (s)
Directive 81, 2012-2013 RRA Decision	The Commission Panel, in the interests of providing a foundation upon which to examine the issue, directs FEU to provide a report detailing the rate impacts of four differing scenarios based on expensing EEC expenditures, and on amortizing them over a 5, 10 and 20-year period. This report is to be included with the next the next EEC expenditure application and each of these scenarios should incorporate the following: • An estimate of EEC program expenses for each year up to and including 2013; • All EEC funds estimated to be spent by the end of 2013 and EEC forecast expenses for 2014 and beyond; • Rate impacts for a 20 year period beginning in 2014; and • Estimates of inflation for EEC Expenditures.	The requested report is included in this RRA.	Appendix I: Section 8.2, Attachment I3.
Directive 4, page 4, Appendix H to Report on Inquiry into the Offering of Products and Services in Alternative Energy Solutions and other New Initiatives	The Commission Panel finds that where there is a potential conflict of interest because the FEU may be providing capital or services to a project receiving the DSM or other incentive funds, there should be a neutral third party involved in the decision making process to award such funds. FEU's proposed guidelines do not sufficiently protect against this potential conflict of interest. Accordingly, the FEU are directed to bring forward a proposal for mechanisms for approval and administration of funds by a neutral third party where the FEU may be involved in providing capital or services to a project receiving DSM or other incentive funds and/or there is a potential for FEU to benefit, either directly or indirectly, from that funding.	The FEU have engaged Price Waterhouse Coopers to act as a fairness advisor in cases where EEC funds are being provided to projects with a third party thermal energy component. Their proposal is included at Attachment I4.	Attachment I4.

4. HISTORICAL EXPENDITURE LEVELS

Fortis BC has now ramped up our EEC spending to match the levels sought in the 2012/2013 RRA period. For historical reference, the table I-3 shows the incentive and non-incentive expenditures since 2009, the year in which the Commission granted the Companies approval to significantly increase EEC activity. The 2012 EEC Annual Report provided in Attachment I2 shows (as do prior annual reports) that EEC spending in each of these years has been cost effective.

Table I-3: Incentive and Non-Incentive Expenditures Since 2009

EEC Expenditures since April 2009 ($000's)								
	2009		2010		2011		2012	
	Incentive	Non-Incentive	Incentive	Non-Incentive	Incentive	Non-Incentive	Incentive	Non-Incentive
FEI	$3,245	$2,498	$10,548	$5,261	$5,669	$7,668	$12,635	$8,082
FEVI	$98	$419	$870	$1,022	$1,448	$1,397	$1,792	$1,251

The financial treatment of EEC expenditures approved in the 2012-2013 RRA Decision was designed to mitigate Commission and Stakeholder concerns regarding actual expenditures coming in below approved levels, as was the case in the early years of our programs. Under the approved treatment, $15 million of expenditures are placed into rates in each of 2012 and 2013, and the difference between the $15 million and actual expenditure levels up to the approved amount placed into rates at the end of the test period, when the actual amounts are known. As discussed later in the document, given that factors beyond the FEU's control, such as the economy and cost of gas, continue to impact the level of EEC expenditures that will be possible in any given year, the Companies are proposing to continue this accounting treatment over the PBR period.

5. EEC PLAN AND FUNDING REQUEST

The 2014-2018 EEC Plan (EEC Plan) in Attachment I1 covers the EEC funding request for the 2014-2018 RRA for the FEU (the Companies) for previously approved Program Areas: Residential, Low Income, Commercial, Conservation Education and Outreach, Industrial, and Innovative Technologies.

A five year funding approval is being requested in order to establish certainty in the market that FEU will be able to offer the programs listed in the EEC Plan over an extended period. This will allow external parties such as contractors, manufacturers and other program partners to better support EEC initiatives knowing that they will be established for the long term. It will also enable FEU to take advantage of program momentum and it will spare EEC resources from extensive regulatory work so they can dedicate their time to program development and operation.

Many of the programs in this EEC Plan are continuations of previously-approved programs that the FEU are currently running, and has reported on in their 2011 and 2012 EEC Annual Reports. The EEC Plan is intended to provide program details and projected cost-effectiveness results for the FEU's proposed portfolio of EEC Program Area activity over the 2014-2018 time period.

The information presented in the EEC Plan involved a collaborative working effort between the Companies EEC program personnel and ICF Marbek staff. More details on the approach undertaken to develop the EEC Plan can be found in section 1 of the plan (Attachment I1).

5.1 *FUNDING REQUEST BY PROGRAM AREA*

The FEU's 2012 Actual Expenditure, 2013 Approved Expenditure and the proposed expenditures for 2014-2018 in each of the Program Areas are outlined in the table below:

Table I-4: FEU EEC Expenditures - 2012 Actual, 2013 Approved and 2014-2018 Proposed[7]

	Actual Expenditures ($000s)	Approved Expenditures ($000s)	Requested Expenditures ($000s)				
Program Area	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Residential	11,295	10,623	10,558	11,152	11,110	10,700	11,383
Low Income	603	4,969	2,629	2,822	3,042	3,247	3,483
Commercial	4,865	12,708	11,132	11,573	10,972	10,416	10,051
Industrial	358	1,756	1,912	2,357	2,662	2,983	2,983
Innovative Technologies	394	1,502	1,207	1,218	1,233	1,218	1,210
CEO	2,200	4,016	2,400	2,400	2,400	2,400	2,400
Enabling Activities	4045*	n/a	4,515	5,015	4,420	4,425	4,365
Totals	19,715	35,574	34,353	36,537	35,839	35,388	35,874

* The value for Enabling Activities for 2012 is in fact for Portfolio-level activity

[7] Requested expenditures listed are presented in 2014 dollars and do not include inflation.

It can be seen in the table above that the funding levels being requested for most program areas are relatively stable, with two exceptions: the Low Income and Conservation Education and Outreach program areas. When the actual and approved funding levels were reviewed, it was determined that reaching approved funding levels would be a challenge. In the Low Income program area, the Companies have been challenged to intake participants into the Energy Conservation Assistance Program (ECAP), the direct-install initiative. Finding potential participants for ECAP is difficult, and getting past the barriers of enrolling them has been hard as this customer group can be mistrustful and is focussed on getting through the day-to-day rather than on energy matters. In the Conservation Education and Outreach areas, the program team concluded that absent the opportunity to promulgate the FEU's conservation messaging using the medium of television, it would be hard to reach approved funding levels. The program teams in the other program areas concluded that approved funding levels were more attainable, so funding levels for the other program areas remain fairly consistent with historically approved levels.

5.2 *NEW AND PREVIOUSLY APPROVED PROGRAMS*

Most of the programs listed in the EEC Plan are continuations of existing programs ongoing from the previous test period or programs that were previously approved. In the EEC Plan, FEU is requesting funding for 6 new programs for 2014 – 2018. Table I-5 lists all of the programs listed in the EEC Plan categorized by "Approved for 2012 - 2013" and "New". Note that in the Commercial and Conservation Education and Outreach program areas, multiple previously approved programs have been consolidated into a single program. Further details, full descriptions and approximate timelines for each program listed in Table I-5 can be found in the EEC Plan (Attachment I1). References are provided for program detail for new programs.

Table I-5: Programs Classified by Previously Approved and New

Program Area	EEC Plan 2014 - 2018 Programs	Approved for 2012 - 2013	New
Residential	Energy Efficient Home Performance Program	X	
	Furnace Replacement Program	X	
	EnerChoice Fireplace Program	X	
	Appliance Service Program	X	
	ENERGY STAR® Water Heater Program	X	
	Low-Flow Fixtures	X	
	New Home Program	X	
	New Technologies Program[8]		X
	New Technologies Program		
	Customer Engagement Tool for Conservation Behaviors	X	
	Financing Pilot	X	

[8] Attachment I-1 FEU EEC 2014-2018 Plan, page 30

Program Area	EEC Plan 2014 - 2018 Programs	Approved for 2012 - 2013	New
Commercial	Space Heat Program	X	
	Water Heating Program	X	
	Commercial Food Service Program	X	
	Customized Equipment Upgrade Program	X	
	EnerTracker Program	X	
	Continuous Optimization Program	X	
	Commercial Energy Assessment Program	X	
	Energy Specialist Program	X	
	Mechanical Insulation Pilot[9]		X
Industrial	Industrial Optimization Program	X	
	Specialized Industrial Process Technology Program[10]		X
Low Income	Energy Savings Kit	X	
	Energy Conservation Assistance Program	X	
	REnEW	X	
	Low Income Space Heat Top-Ups[11]		X
	Low Income Water Heating Top-Ups[12]		X
	Non-Profit Custom Program[13]		X
Conservation Education & Outreach	Residential Education Program	X	
	Commercial Education Program	X	
	School Education Program	X	

5.3 *PLAN FLEXIBILITY AND ADJUSTMENT*

It should be noted that as with all plans, this EEC Plan is subject to change in response to changes in market conditions, customer responses to programs, input from stakeholders including program partners, and changes in the political environment in which the Companies operate. Due to the length of the period the EEC Plan covers, the Companies require the

9 Attachment I-1 FEU EEC 2014-2018 Plan, page 58
10 Attachment I-1 FEU EEC 2014-2018 Plan, page 66
11 Attachment I-1 FEU EEC 2014-2018 Plan, page 78
12 Attachment I-1 FEU EEC 2014-2018 Plan, page 80
13 Attachment I-1 FEU EEC 2014-2018 Plan, page 82

flexibility to be able to adjust to new information, program results and opportunities through the test period without the need for a full Commission review.

The Companies propose that program funding transfer rules follow the same process as was directed by the Commission for the 2012-2013 test period except with regards to the transfer of funds to new programs. The existing program funding transfer rules are as follows:

- Funding transfers under 25 percent from one approved Program Area to another approved Program Area would be permitted without prior approval of the Commission.
- In cases where a proposed transfer out of an approved Program Area is greater than 25 percent of that approved Program Area, prior Commission approval would be required.
- In cases where a proposed transfer into an approved Program Area is greater than 25 percent of that approved Program Area, prior Commission approval would be required.
- The transfer of any amount of funds from an approved Program Area to Innovative Technologies would require prior Commission approval.

In addition, the Companies propose that they be permitted to launch new programs without pre-approval from the Commission as follows:

- The transfer of funds within an approved Program Area from an existing program to a new program not previously put forth in a Revenue Requirements Application would be permitted if this new program meets with the DSM Regulation, EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

This new funding transfer rule will allow the FEU to take advantage of opportunities that emerge over the course of the PBR period that have not been identified to date or are not sufficiently developed to propose at this time. Given the 5-year PBR period, this flexibility is important to ensure that cost effective demand-side measure opportunities are developed and initiated in a timely manner. The FEU would still comply with all cost-effectiveness tests, reporting and other requirements for these new programs.

5.4 *EEC GUIDING PRINCIPLES*

In the FEU's original EEC Application, the FEU presented a set of principles that the Companies proposed would guide the EEC activity. Many of them were based on a report prepared for the Canadian Gas Association in 2005 by IndEco Consulting in association with B. Vernon and Associates. The Companies are not proposing any significant changes to the principles; some minor changes are incorporated in the EEC Guiding Principles presented below.

1. Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential, commercial and industrial[14] customers, including low income customers through the DSM for Affordable Housing initiative.
2. Wherever possible, programs will be uniform, so that customers in one part of the service territories of the FortisBC Energy[15] Utilities have access to the same programs as customers throughout the service territories.
3. EEC expenditures will have a goal of non-incentive costs not exceeding 50 percent of the expenditure in a given year.[16]
4. Program results will be analyzed on a portfolio-wide basis.
5. The combined Modified Total Resource Cost/Benefit and Total Resource Cost/Benefit of the Portfolio over the funding period will have a ratio of 1 or higher.[17]
6. The FortisBC Energy[18] Utilities will submit an Annual EEC Report to the BCUC, by the end of the first quarter of each year that details the results of the previous year's activity.[19]
7. To every extent practical, programs will support the objectives of established government policies.
8. The Companies will continue to seek funding for programs from additional sources, such as the provincial and federal governments, other utilities, and equipment suppliers and manufacturers, in order to minimize the cost impacts of EEC programs to ratepayers, and in recognition of the broader societal benefits resulting from successful program development and implementation.
9. Incentives may be directed to the end users of an appliance, to the customer point of contact at the time that an equipment purchase decision is made (for example, to the gas contractor in the case of a furnace), to a system designer or engineer, or to an equipment developer, supplier or manufacturer. The most effective use of incentives will be determined through the program design process.
10. Education and outreach regarding conservation will be part of the Companies' EEC activity.
11. Programs will be multi-year so as to create a sense of funding certainty necessary to effective implementation in the marketplace – this Application requests funding for a five-year Portfolio of EEC programs.[20]

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14 Reference to industrial customers added.
15 Company name change
16 Minor wording change
17 Reference to MTRC added; reference to RIM deleted.
18 Company name change
19 Reference to forecasting activity for the upcoming year deleted as this material is now filed in the DSM plan submitted to support requests for Expenditure Schedule approval.
20 Funding period is five years in this request for approvals.

12. Programs will have market transformation as their ultimate goal wherever possible, and program plans will describe how a program will contribute to market transformation.[21]

13. Programs will aim to develop capacity within the market through manufacturers, distributors, vendors and installers.

14. To ensure value creation and alignment with the market, the Companies will establish and engage an EEC stakeholder group, comprised of governments, industry, trades, manufacturers, NGOs, advocacy groups, other utilities and customers to provide it with advice on effective program design and implementation.[22]

The FEU continue to be guided by these principles in designing and carrying out their EEC program.

21 "Wherever possible" added to accommodate such programs as furnace servicing that do not necessarily support a government regulation, but that have merit nonetheless.

22 Reference to consolidating stakeholder activity with other entities deleted as the EECAG seems to be functioning well with a Terms of Reference established.

6. COST EFFECTIVENESS APPROACH

6.1 COST-EFFECTIVENESS UNDER THE DEMAND-SIDE MEASURES REGULATION

The FEU's proposed EEC portfolio for the 2014-2018 funding period is cost-effective according to the currently approved approach to determining cost-effectiveness. As shown in Attachment I1, the portfolio passes the cost-effectiveness tests as currently required by the Commission. The following discussion explains these cost-effectiveness tests and shows that the proposed EEC Plan also meets the requirements of the provincial Demand-Side Measures Regulation. The FEU submit that the current approach to determining the cost-effectiveness of its EEC programs is comprehensive, benefits customers and should be carried forward through the 2014-2018 test period.

The relevant parameters set out in the Demand-Side Measures Regulation are summarized below. Other considerations for determining the cost-effectiveness of the Companies 2014-2018 EEC Plan are covered in the remainder of Section 6 below.

6.1.1 Portfolio-Level Analysis

Section 4(1) of the Demand-Side Measures Regulation stipulates that the Commission, in determining the cost-effectiveness of a demand-side measure proposed in an expenditure portfolio or a plan portfolio, may compare the costs and benefits of (a) a demand-side measure individually, (b) with other demand-side measures in the portfolio or (c) the portfolio as a whole. The FEU maintains that portfolio-level analysis remains the appropriate level of cost-effectiveness testing.

In the 2008 EEC Application Decision,[23] and in each subsequent EEC funding decision, the Commission has determined that the cost-effectiveness of EEC activity should be measured at the portfolio level. In its Decision on the FEU's 2012-2013 RRA,[24] the Commission approved the assessment of cost-effectiveness on an overall portfolio basis, with the assurance that the FEU will continue to monitor EEC programs on a monthly basis to ensure the EEC portfolio meets a combined TRC/MTRC of 1 or greater. There are several reasons to continue with the portfolio approach going forward:

- According to Sections 4(4) and 4(5) of the Demand-Side Measures Regulation, the Commission must, at a minimum, use the portfolio approach in assessing the cost effectiveness of "specified demand-side measures"[25] and "public awareness programs".[26]

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[23] Order G-36-09
[24] Decision and Order G-44-12
[25] "Specified demand-side measures" include: education programs for students, funding for energy efficiency training, funding for codes and standards development, funding to support development of or compliance with a specified standard, a community engagement program and a technology innovation program.
[26] A "public awareness program" means a program delivered by a public utility that the Commission is satisfied will likely: (a) increase the awareness of the public about ways to increase energy conservation and energy efficiency

- A portfolio approach to cost-effectiveness analysis promotes the Companies' goal of making EEC accessible to all customers. Residential programs often have difficulty passing the total resource cost test (TRC) and even the modified TRC (MTRC) on a program-by-program basis, and low-income programs are especially challenged by the cost-effectiveness test. Moving away from a portfolio approach might result in fewer EEC programs being available to residential and low-income customers.
- The portfolio approach permits the Companies to encourage increasing levels of efficiency in natural gas equipment. Equipment that is relatively new to the market may have a higher initial cost due to the fact that it has not yet reached economies of scale. A program based on such equipment is more likely to have low TRC and MTRC results. Although the near term results of such a program might be unfavourable, the long term prospects for such equipment to provide benefits to customers could be significant. The Portfolio level cost-effectiveness analysis can absorb some of these types of programs without failing the cost-effectiveness tests.

For these reasons, the currently-approved portfolio approach remains appropriate for determining the cost effectiveness of EEC activity. For information purposes, the FEU will continue to report on individual EEC program cost-effectiveness results in its Annual Reports, and individual program cost-effectiveness projections are also provided in the 2014-2018 EEC Plan included as Attachment I1.

6.1.2 Total Resource Cost Test

According to Section 4(2) of the Demand-Side Measures Regulation, determinations of cost-effectiveness must be made by applying the TRC test and, pursuant to amendments made by the Province in December 2011, the MTRC test (see Section 5.1.3). The TRC is calculated at the Portfolio level by comparing the costs of the portfolio to the total value of the benefits of the programs contained in the portfolio. This Regulation also includes special consideration for specified measures (Section 4(4)) and low income programs (Section 4(2)).

The cost-effectiveness of a specified demand-side measure must be determined by the cost effectiveness of the portfolio as a whole. Specified demand-side measures include education programs, energy efficiency training, community engagement programs, technology innovation programs and resources supporting the development of or compliance with energy efficiency standards.[27] The FEU have specified demand-side measures within their Conservation, Education and Outreach (CEO), Innovative Technologies and Enabling Initiatives Program Areas.

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or to encourage the public to conserve energy or use energy efficiently, or (b) increase participation by the public utility's customers in other DSM proposed by the public utility.

[27] For a more detailed description of specified demand-side measures see Section 1 of the British Columbia Demand-Side Measures Regulation.

A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption (which would include the activity defined within the FEU's Low Income Program Area) the Commission must use, "in addition to any other analysis the Commission considers appropriate," the TRC test and consider the benefit of the demand-side measure to be 130 percent of its value. The Companies have applied this approach in the cost-effectiveness analysis of the Low Income programs presented in the 2014-2018 EEC Plan.

6.1.3 Modified Total Resource Cost Test

Amendments to the Demand-Side Measures Regulation in 2011 included the addition of subsection 4(1.1) allowing for the use of a modified TRC (MTRC) for up to 33 percent of the natural gas DSM portfolio, excluding specified demand-side measures. The FEU manages its activities carefully to stay within this MTRC Cap. The MTRC includes two new components: the use of a zero-emission energy supply alternative (ZEEA) in determining avoided cost of energy for DSM, and the inclusion of non-energy benefits (NEB) to customers and the utility. These components are described below.

6.1.3.1 Zero Emission Energy Alternative

The benefits of demand side measures in the standard TRC calculation include the avoided cost of new energy transmission capacity and the avoided cost of the energy. In calculating the MTRC, the ZEEA is applied to these standard benefits in determining the avoided cost of energy. Use of the ZEEA recognizes that avoiding natural gas use has similar GHG emission reduction benefits to that of employing clean electricity to meet that energy need. The ZEEA is defined in the Demand-Side Measures Regulation as BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia. The Demand-Side Measures Regulation allows the inclusion of 50 percent of the ZEEA value as a benefit in the MTRC calculation for natural gas demand side measures. At the time of writing, the ZEEA value used in the MTRC calculation is 50 percent of $129/MWh[28], or $18.32/GJ. The source for this number is BC Hydro's October 2010 Report on the RFP Process for the Clean Power Call Request for Proposals, and this value is consistent with the number used to calculate the MTRC for the 2012 EEC Annual Report. It was confirmed with BC Hydro that this value would be the appropriate value to use at this point in time. There is uncertainty at the time of writing as to BC Hydro's long run marginal cost for clean power over the entire test period, so it was determined by the Companies that an approach to calculating the ZEEA consistent with that taken historically by the Companies would be the most appropriate to take at this time. Regarding Section 4(1.2) of the Demand Side Measures Regulation, the ZEEA applies to the proposed portfolio of EEC activity for the period 2014-2018 because the activity reduces the use of natural gas and the amount of GHG emissions associated with the use of natural gas.

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[28] Source: http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/acquiring_power/2010q3/cpc_rfp_process_report.pdf Table 3.5, page 12

6.1.3.2 Inclusion of Non-Energy Benefits

Section 4(1.1)(c) of the Demand-Side Measures Regulation requires the Commission to allow the inclusion of NEBs, the amount of which may be determined either by the Commission based on evidence from the utility or by using a deemed 15 percent adder to the benefits side of the MTRC calculation. The FEU have chosen to use the 15 percent NEB adder in its MTRC calculations for the 2014 – 2018 EEC Plan.

6.2 ELEMENTS OF THE STANDARD COST BENEFIT TESTS

While the TRC and MTRC continue to be the cost-effectiveness tests that the FEU are putting forward for determining the portfolio cost-effectiveness, the Companies have also historically reported on a range of other standard cost-effectiveness tests used by the industry to monitor programs, Program Areas and the portfolio as a whole. The standard cost-effectiveness tests are the TRC, the Ratepayer Impact Measure (RIM), the UCT[29] and the Participant Cost Test (PCT) calculations at the program, Program Area and portfolio level. These are consistent with the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects (California Manual), and will be applied consistently with past practice during the 2014-2018 period. Specific proposals regarding two elements of these tests are discussed below.

6.2.1 Net-to-Gross (NTG) Ratio: Spillover and Free Riders

Historically, the way in which the FEU calculated NTG only adjusted the benefits downward for the presumed presence of “free riders”, i.e. individuals who participate in an incentive program who would have upgraded their equipment even in the absence of an incentive. The FEU believe that the NTG should also account for the benefit of customers that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the incentive program. Accounting for this effect, known as “spillover”, in the NTG is a recognized approach that is used by many utilities including BC Hydro.[30] As “spillover” is the conceptual opposite of “free riders”, including both effects presents a more complete and balanced view of program impacts.

In the 2012-2013 RRA Application, the FEU sought the Commission’s endorsement of the appropriateness of recognizing spillover effects in the NTG ratio on the FEU’s portfolio as a basis for the FEU to proceed with evaluating and quantifying spillover effects on the approved EEC portfolio. Further, the FEU proposed that in future applications for EEC funding, the FEU would propose specific free rider and spillover estimates based on the results of that evaluation.

In the 2012-2013 RRA Decision, the Commission Panel determined that it would not be appropriate to make a determination on the inclusion of spillover without a full assessment of the merits of including spillover based on a specific set of facts before the Commission. Accordingly, the Commission Panel made no determination on the inclusion of spillover in the

[29] Referred to as Program Administrator Cost Test in the California Manual
[30] 2012-2013 RRA Exhibit B-9, BCUC IR 1.210.2.

2013-3013 RRA. The Commission indicated that the FEU could readdress this issue in future applications.

In this RRA, the FEU seek the Commission's endorsement of the appropriateness of recognizing spillover effects in the NTG ratio on a case-by-case basis where evaluation shows that spillover is occurring.

In the 2014-2018 EEC Plan, FEI has included a spillover rate for one program, the Residential Energy Efficient Home Performance Program. This program is conducted in conjunction with the Province of British Columbia, and BC Hydro and has historically been known as LiveSmart BC. As part of the LiveSmart BC evaluation, surveys have been completed to statistically evaluate the extent of spillover effects. At the time of writing this Application, the LiveSmart BC evaluation results were not yet released to partners; however, the program evaluation team has indicated that there were spillover effects in both the participant and non-participant survey groups. Therefore, in the 2014-2018 EEC Plan, the FEU has included a conservative 15 percent spillover rate for this program until the formal evaluation is available. FEI will update the spillover rate based on the statistical evaluation for LiveSmart BC when it becomes available.

The FEU intend to continue evaluating and quantifying spillover effects on a program-by-program basis. Where adequate estimates are developed or acquired based on the results of that evaluation, free rider and spillover effects would be accounted for in the NTG ratio as appropriate, and reported on and highlighted in the EEC Annual Report. The FEU submit that it is in the best interests of customers for the Commission to make a determination in this Application regarding the principle of including spillover effects before more detailed work is undertaken.

6.2.2 Attribution of Savings from the Introduction of Regulation

According to Section 4(1.4) of the Demand-Side Measures Regulation, in considering a demand-side measure that, in the Commission's opinion, will increase the use of a regulated item with respect to which there is either:

a) a specified standard that has not yet commenced, or

b) a specified proposal.

The Commission, after applying subsection (1.1), may increase the benefit of the demand-side measure by an amount that represents a portion of the avoided capacity and energy costs that, in the Commission's opinion, will result from the commencement and application of the specified standard, amendment or new bylaw proposed by the specified proposal, assuming that the standard, amendment or new bylaw comes into force.

There are no programs in the FEU's proposed portfolio outlined in the 2014-2018 EEC Plan for which attribution of energy savings from the introduction of codes and standards has been applied in the figures presented therein.

Pursuant to this element of the DSM Regulation, the Companies intend to attribute the benefit of savings from the introduction of codes and standards on a program-by-program basis where such an attribution can be supported. The analysis of cost-effectiveness presented in the 2014-2018 does not incorporate such attribution; however the Companies are seeking the Commission's endorsement of the concept for reporting purposes. It is the intent of the Companies to incorporate savings from the introduction of codes and standards on a case-by-case basis and to report on and highlight this practice in the EEC Annual Report.

7. EVALUATION, MEASUREMENT & VERIFICATION

The Companies consider Evaluation, Measurement and Verification (EM&V) to be an important aspect of the overall EEC program lifecycle. As more programs reach maturity and enough program data becomes available, the Companies will complete more program evaluations at appropriate times in the program life cycles and provide those evaluation results to stakeholders and the Commission. Three key aspects of the Companies' EM&V activities are addressed in the following discussion: the 2014-2018 Evaluation Plan, the Companies' EM&V Framework and a directive from the Commission to develop attribution rules for claiming energy savings from multi-utility programs.

7.1 *EVALUATION PLAN*

Attachment I7 contains the Companies' 5 Year Evaluation Plan, covering the 2014 to 2018 period for its EM&V activities, including evaluations for process, impact, and communications, as well as measurement and verification activities for its current and planned EEC programs and pilots. Overall program expenditures reported in Section 2.1 include costs for EM&V activities: however, the EM&V costs are also reported in the Evaluation Plan to provide an easy-to-view summary of the evaluation expenditures together with the 5 Year Evaluation Plan. The total proposed expenditure for program evaluation and M&V activities to be conducted from 2014 to 2018 is approximately $7,404 thousand. The proposed budget aligns with the Companies EM&V Framework and industry general practice[31] for budget spending on EM&V activities, representing 4.1 percent of the Companies' total EEC portfolio expenditure.

7.2 *EM&V FRAMEWORK*

The FEU developed an EM&V Framework in 2012 to formalize the background, objectives, principles and general practices that guide the Companies' approach, resources and timeframes for EM&V activities. The framework addresses the following Commission directive from the 2012-2013 RRA Decision.

> *"The Commission Panel sees benefit in the establishment of an EM&V Framework. The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework."*

The draft EM&V Framework was presented to the EECAG at the fall 2012 workshop. The Companies are finalizing the EM&V Framework in 2013, taking into consideration feedback received from the EECAG and our evaluation partners. The EM&V Framework will be updated

[31] California Evaluation Framework. June 2004. TecMarket Works.

periodically to meet any new industry standards and best practices that may be adopted from time to time.[32] Attachment I8 contains the current draft EM&V Framework.

7.3 ATTRIBUTION RULES FOR MULTI-UTILITY PROGRAMS

In its 2012-2013 RRA Decision, the Commission directed the FEU to develop attribution rules for all integrated programs which prevent the double counting of savings claimed by each utility. Currently, the double counting of energy savings between utilities is avoided by the FEU as the Companies only claim the natural gas energy savings achieved as a result of their EEC programs. For clarity, where FEU is working jointly with electric utilities on EEC programs, the utilities work together to ensure the appropriate costs for both electricity and natural gas as well as both electricity and gas savings are included in in the cost effectiveness tests. However, with respect to tracking the energy savings and emission reductions that each utilities' DSM programs achieve, only the electric utilities have claimed the electricity savings from joint programs and only FEU, to the best of the Companies' knowledge, have claimed or reported the natural gas savings and resulting emission reductions. Going forward, the FEU will continue their work in developing more comprehensive attribution rules in cooperation with BC Hydro and FortisBC's electric utility so that reporting of the benefits of combined programs is maximized while avoiding the potential for double counting of energy savings.

[32] The Companies refer to the California Evaluation Framework. June 2004. TecMarket Works, IPMVP – Concepts and Options for Determining Energy and Water Savings. Efficiency Valuation Organization. January 2012. for guidance of the industry standards and best practices.

8. ADDITIONAL APPROVALS SOUGHT

8.1 *ACCOUNTING TREATMENT*

Consistent with the treatment requested in the 2012-2013 RRA and approved through Commission Order G-44-12, this Application includes combined FEU EEC rate base deferral account additions of $15.0 million in 2014, and for each year after through 2018, included on a net-of-tax basis, allocated amongst the FEU on an average customer basis, and amortized in rates over a ten year period.

In this Application, FEI is seeking approval to transfer the balance accumulated in the non-rate base EEC Incentive deferral at the end of 2013 to the rate base EEC deferral account on January 1, 2014.

Additionally, FEI will use the non-rate base EEC Incentive deferral account to continue accumulating the annual spending difference between the $15.0 million forecasted in FEU rate base up to the approved FEU annual funding envelope. FEI is seeking approval to transfer any new amounts accumulated in this account relating to FEI, during the 2014 – 2018 revenue requirement period, to the FEI rate base EEC deferral account in the following year, with amortization over 10 years commencing the year in which the balance is transferred.

Please refer to Section D4 and Appendix F-5 of this Application for discussion on these requests.

8.2 *AMORTIZATION PERIOD*

In the 2012-2013 RRA Decision, the Commission directed the FEU as follows (at pages 184-185):

> *"The Commission Panel, in the interests of providing a foundation upon which to examine the issue, directs FEU to provide a report detailing the rate impacts of four differing scenarios based on expensing EEC expenditures, and on amortizing them over a 5, 10 and 20-year period. This report is to be included with the next the next EEC expenditure application and each of these scenarios should incorporate the following:*
>
> - *An estimate of EEC program expenses for each year up to and including 2013;*
> - *All EEC funds estimated to be spent by the end of 2013 and EEC forecast expenses for 2014 and beyond;*
> - *Rate impacts for a 20 year period beginning in 2014; and*
> - *Estimates of inflation for EEC Expenditures."*

To comply with this directive, the FEU have provided the requested analysis in Attachment I3, which includes all of the general assumptions and requirements requested by the Commission. The tables below for each of the three utilities summarize the rate impacts under the four scenarios.

Table I-6: FEI Cumulative Delivery Rate Impacts

Cumulative Delivery Rate Impact Compared to 2013 Approved	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scenario 1: Expensing EEC Expenditures	15.91%	4.29%	4.20%	4.16%	4.28%	4.30%	4.33%	4.35%	4.37%	4.39%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.95%	3.10%	4.23%	5.25%	6.16%	5.00%	5.07%	5.08%	5.11%	5.15%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.83%	1.58%	2.33%	3.02%	3.65%	4.25%	4.81%	5.33%	5.80%	6.24%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.27%	0.83%	1.39%	1.90%	2.39%	2.87%	3.31%	3.74%	4.14%	4.51%

Cumulative Delivery Rate Impact Compared to 2013 Approved	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Scenario 1: Expensing EEC Expenditures	4.41%	4.43%	4.45%	4.47%	4.49%	4.51%	4.53%	4.54%	4.56%	4.58%
Scenario 2: Amortizing EEC Expenditures over 5 years	5.17%	5.19%	5.21%	5.23%	5.24%	5.26%	5.28%	5.30%	5.32%	5.33%
Scenario 3: Amortizing EEC Expenditures over 10 years	5.72%	5.77%	5.78%	5.80%	5.83%	5.85%	5.87%	5.88%	5.90%	5.92%
Scenario 4: Amortizing EEC Expenditures over 20 years	4.87%	5.20%	5.52%	5.81%	6.08%	6.34%	6.58%	6.80%	7.00%	7.19%

Table I-7: FEVI Cumulative Notional Delivery Rate Impacts

Cumulative Notional Delivery Rate Impact Compared to 2013 Approved	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scenario 1: Expensing EEC Expenditures	6.20%	1.60%	1.62%	1.62%	1.59%	1.60%	1.61%	1.61%	1.62%	1.63%
Scenario 2: Amortizing EEC Expenditures over 5 years	0.83%	1.24%	1.65%	2.02%	2.36%	1.87%	1.89%	1.89%	1.88%	1.88%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.39%	0.66%	0.93%	1.18%	1.41%	1.62%	1.81%	2.00%	2.16%	2.32%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.17%	0.37%	0.56%	0.75%	0.93%	1.09%	1.25%	1.40%	1.54%	1.67%

Cumulative Notional Delivery Rate Impact Compared to 2013 Approved	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Scenario 1: Expensing EEC Expenditures	1.63%	1.64%	1.65%	1.65%	1.66%	1.67%	1.67%	1.68%	1.68%	1.69%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.89%	1.90%	1.90%	1.91%	1.92%	1.92%	1.93%	1.94%	1.94%	1.95%
Scenario 3: Amortizing EEC Expenditures over 10 years	2.10%	2.11%	2.11%	2.11%	2.12%	2.12%	2.13%	2.13%	2.14%	2.15%
Scenario 4: Amortizing EEC Expenditures over 20 years	1.79%	1.91%	2.02%	2.12%	2.22%	2.31%	2.39%	2.47%	2.54%	2.60%

Table I-8: FEW Cumulative Delivery Rate Impacts

Cumulative Delivery Rate Impact Compared to 2013 Approved	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Scenario 1: Expensing EEC Expenditures	9.75%	4.15%	4.08%	4.03%	4.10%	4.11%	4.11%	4.12%	4.12%	4.13%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.24%	2.22%	3.18%	4.06%	4.86%	4.61%	4.65%	4.65%	4.65%	4.67%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.69%	1.31%	1.93%	2.49%	3.02%	3.52%	3.98%	4.42%	4.82%	5.19%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.42%	0.86%	1.30%	1.71%	2.10%	2.47%	2.83%	3.17%	3.48%	3.78%

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative Delivery Rate Impact Compared to 2013 Approved										
Scenario 1: Expensing EEC Expenditures	4.14%	4.14%	4.15%	4.15%	4.16%	4.16%	4.17%	4.17%	4.18%	4.18%
Scenario 2: Amortizing EEC Expenditures over 5 years	4.68%	4.68%	4.69%	4.69%	4.70%	4.70%	4.71%	4.71%	4.72%	4.72%
Scenario 3: Amortizing EEC Expenditures over 10 years	5.08%	5.10%	5.10%	5.11%	5.12%	5.13%	5.13%	5.14%	5.14%	5.15%
Scenario 4: Amortizing EEC Expenditures over 20 years	4.07%	4.34%	4.59%	4.82%	5.05%	5.25%	5.45%	5.63%	5.79%	5.95%

As demonstrated by the results shown in the tables above, expensing EEC expenditures would result in significant rate increases for customers and should be considered an unnecessary burden on customers that can be avoided through a longer amortization term. Further, even a 5-year amortization period would produce a delivery rate increase of approximately 2 percent for FEI customers in 2014. If FEI had used a 5-year amortization period for the EEC deferral in this Application, the delivery rate impacts from this one account alone would have been a significant portion of the overall delivery rate increase requested in this Application. FEI believes the currently approved amortization period of 10 years is acceptable for the EEC deferral account, but would be amenable to a longer amortization period for the reasons provided. A longer amortization period results in steady and manageable rate increases for customers and provides the FEU with the opportunity to continue requesting EEC funding envelopes that adequately support customer energy efficiency needs.

Attachment I1

FEU EEC 2014-2018 PLAN

ICF Marbek
an ICF International Company


FortisBC EEC Plan 2014-2018

Program Description and Cost-Effectiveness Results

Final Report

May 2, 2013

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Table of Contents

1 Introduction

1.1 Background and Objectives

This Energy Efficiency and Conservation (EEC) Plan covers the funding request in FortisBC's 2014-2018 Revenue Requirements Application (RRA) for the following previously approved program areas:

- Residential Energy Efficiency Program Area
- Commercial Energy Efficiency Program Area
- Industrial Energy Efficiency Program Area
- Low Income Energy Efficiency Program Area
- Conservation Education and Outreach Initiatives
- Innovative Technologies Program Area
- Enabling Activities

This EEC Plan covers all of FortisBC's natural gas utilities, including FEI (Mainland), FEVI (Vancouver Island), and FEW (Whistler), collectively referred to as the Companies. In addition, this plan provides program details and planned cost-effectiveness results for FortisBC's proposed portfolio of EEC program area activity.

Many of the programs in this EEC Plan are continuations of programs that FortisBC is currently operating, and has reported on in their 2011 and 2012 EEC Annual Reports. However, the EEC Plan also includes the following new programs within the approved program areas:

1. New Technologies Program – section 3.4.8
2. Mechanical Insulation Pilot – section 4.5.9
3. Specialized Industrial Process Technology Program – section 5.4.2
4. Low Income Space Heat Top-Ups – section 6.4.4
5. Low Income Water Heating Top-Ups – section 6.4.5
6. Non-Profit Custom Program – section 6.4.6

These new initiatives reflect FortisBC's on-going efforts to respond to changing market conditions and to integrate operational lessons learned from current implementation activities.

As with all long-term plans, this EEC Plan is subject to changes in market conditions, customer responses to programs, input from stakeholders, including program partners, and changes in the political environment in which the Companies operate. Therefore, information and forecasts listed in the Program Profiles represent best estimates as of the filing of this EEC Plan and are subject to adjustments, as required.

1.2 Approach

The information presented in this report was compiled in a similar manner as the FortisBC Energy Utilities 2012-2013 EEC Plan filed in 2011. The process involved a collaborative working effort between FortisBC EEC program personnel and ICF Marbek staff that employed the following steps:

- FortisBC program managers identified and provided a description of the individual programs included within their respective portfolios, including eligible measures, target markets and potential delivery partners.

- Drawing on a combination of previous FortisBC EEC market experience, relevant technology and market studies,[1] and, in some cases, professional estimates, FortisBC EEC managers completed Profiles for each program within their portfolio. Individual Profiles are included in the body of this report.

- ICF Marbek staff worked from the Program Profiles provided by FortisBC staff and populated the cost-effectiveness model. Initial results were generated at the level of total EEC program portfolio, program area (e.g., Residential, Commercial, etc.) and individual program.

- The initial results were reviewed collaboratively and revisions were made, as necessary.

- The final results were compiled into the current report.

1.3 Report Organization

The remainder of this report is presented in the following sections:

- Section 2 provides an overview of the **EEC Program Portfolio Results.**

- Section 3 provides a description of the individual programs and cost-effectiveness results for the **Residential Energy Efficiency Program Area.**

- Section 4 provides a description of the individual programs and cost-effectiveness results for the **Commercial Energy Efficiency Program Area.**

- Section 5 provides a description of the individual programs and cost-effectiveness results for the **Industrial Energy Efficiency Program Area.**

- Section 6 provides a description of the individual programs and cost-effectiveness results for the **Low Income Energy Efficiency Program Area.**

- Section 7 provides a description of the individual programs and cost-effectiveness results for the **Conservation Education and Outreach Initiatives.**

- Section 8 provides a description of the individual programs and cost-effectiveness results for the **Innovative Technologies Program Area.**

- Section 9 provides a description of the **Enabling Activities** that are required over the 5-year period to support the overall program effort.

- Section 10 provides a **Summary** of the findings of this report, together with some commentary that puts these results into perspective.

1.4 Notes

The following general notes apply to all the program areas:

- FEW (Fortis Energy Whistler) is included in FEI.

[1] Specific reference sources are provided in the Program Profiles contained in the main body of this report.

- Totals in Exhibits may not add exactly; any differences are due to rounding.

- A "Non-Program Specific Expense" line item has been included in Exhibits for each program area. These planned expenditures represent the costs attributable to that program area but support multiple programs and, therefore, are not specific to only one program. Generally, these expenditures represent items such as training, travel, marketing collateral and consulting services that support the overall program area. The amounts in this plan are based on past reported non-program specific expenses.

    - For all program areas other than the Residential sector, approximately 10% of total planned expenditures have been allocated to this item.

    - For the Residential sector, approximately 5% of total planned expenditures have been allocated to this item. The relative size of these expenditures is lower for this sector since incentive spending represents a large percentage of overall spending in the Residential sector.

2 Overall EEC Program Portfolio Results

2.1 Introduction

This section provides a summary of the total expenditures, estimated natural gas savings, and associated cost effectiveness for FortisBC's proposed portfolio of Energy Efficiency and Conservation (EEC) programs for the 2014-2018 period. The EEC portfolio has been organized into the following program areas:

- Residential Energy Efficiency Program Area
- Commercial Energy Efficiency Program Area
- Industrial Energy Efficiency Program Area
- Low Income Energy Efficiency Program Area
- Conservation Education and Outreach Initiatives
- Innovative Technologies Program Area
- Enabling Activities

2.2 Overall Portfolio Results

The overall EEC program results are summarized in the following exhibits.

- Exhibit 1 provides a summary of expenditures, including inflation. Inflation was assumed to be 3% for FortisBC labour and 2% for all other expenses.[2]

- Exhibit 2 presents the results for the total EEC program portfolio.

- Exhibit 3 summarizes the annual expenditures for the programs that require the MTRC adder and compares these expenses to those for the entire portfolio.

- Exhibit 4 and Exhibit 5 present the results for each individual program area and for the total EEC program portfolio.

[2] Inflation is only accounted for in Exhibit 1. All other expenditures are presented in 2014 dollars.

Exhibit 1 - A Summary of Annual Expenditures Including Inflation

Program Area and Service Territory	Utility Expenditures ($1000s)					
	2014	2015	2016	2017	2018	Total
Residential						
FEI	9,469	10,220	10,396	10,252	11,138	51,476
FEVI	1,089	1,154	1,162	1,102	1,183	5,691
Total	10,558	11,375	11,559	11,355	12,321	57,167
Commercial						
FEI	9,617	10,128	9,623	9,289	9,125	47,782
FEVI	1,515	1,677	1,792	1,765	1,754	8,503
Total	11,132	11,805	11,415	11,054	10,879	56,285
Industrial						
FEI	1,738	2,185	2,516	2,874	2,932	12,245
FEVI	174	220	253	291	297	1,234
Total	1,912	2,404	2,770	3,165	3,228	13,479
Low Income						
FEI	2,307	2,574	2,833	3,044	3,381	14,138
FEVI	322	305	332	401	390	1,750
Total	2,629	2,879	3,165	3,446	3,770	15,888
Conservation Education and Outreach						
FEI	2,160	2,203	2,247	2,292	2,338	11,241
FEVI	240	245	250	255	260	1,249
Total	2,400	2,448	2,497	2,547	2,598	12,490
Innovative Technologies						
FEI	1,106	1,138	1,214	1,199	1,281	5,938
FEVI	101	105	69	93	28	396
Total	1,207	1,242	1,283	1,292	1,309	6,334
Enabling Activities						
FEI	4,109	4,687	4,250	4,374	4,437	21,856
FEVI	406	464	420	433	439	2,162
Total	4,515	5,150	4,670	4,806	4,876	24,017
ALL PROGRAMS						
FEI	30,505	33,134	33,081	33,324	34,632	164,676
FEVI	3,848	4,169	4,278	4,340	4,350	20,984
Total	**34,353**	**37,303**	**37,358**	**37,664**	**38,982**	**185,660**

Exhibit 2 - Results for the Total EEC Program Portfolio[3]

Indicator		Service Territory FEI	Service Territory FEVI	Total
Utility Expenditures, Incentives ($1000s)	2014	17,212	2,331	**19,543**
	2015	18,539	2,547	**21,086**
	2016	18,383	2,638	**21,020**
	2017	17,898	2,557	**20,455**
	2018	18,062	2,494	**20,556**
	Total	**90,093**	**12,567**	**102,660**
Utility Expenditures, Non-Incentives ($1000s)	2014	13,294	1,516	**14,810**
	2015	13,915	1,537	**15,452**
	2016	13,351	1,468	**14,818**
	2017	13,410	1,523	**14,933**
	2018	13,806	1,512	**15,318**
	Total	**67,774**	**7,556**	**75,331**
Utility Expenditures, Total ($1000s)	2014	30,505	3,848	**34,353**
	2015	32,453	4,084	**36,537**
	2016	31,733	4,105	**35,839**
	2017	31,308	4,080	**35,388**
	2018	31,868	4,006	**35,874**
	Total	**157,867**	**20,124**	**177,991**
Annual Gas Savings, Net (GJ/yr.)	2014	637,255	66,693	**703,948**
	2015	1,255,547	136,195	**1,391,743**
	2016	1,733,589	204,155	**1,937,743**
	2017	2,265,196	270,295	**2,535,491**
	2018	2,787,418	336,344	**3,123,762**
NPV of Gas Savings, Net (GJ)		20,694,592	2,808,879	**23,503,471**
Benefit/Cost Ratios	TRC	0.92	1.05	**0.93**
	Portfolio*	1.31	1.29	**1.30**
	Utility	1.29	1.39	**1.30**
	Participant	2.15	3.74	**2.33**
	RIM	0.51	0.36	**0.49**

* Includes the MTRC adder for programs that require it (i.e. TRC/MTRC hybrid)

[3] Inflation is not included in the expenditures noted in this exhibit or in those included in any other exhibits from this point forward. Rather, all expenditures other than those in Exhibit 1 are presented in 2014 dollars.

Exhibit 3 - A Summary of the Expenditures for Programs that Require the MTRC Adder

Program and Service Territory	Utility Expenditures ($1000s)					
	All Spending					
	2014	2015	2016	2017	2018	Total
* Furnace Replacement Program (Residential)						
FEI	3,053	3,040	3,040	3,040	3,030	15,202
FEVI	302	301	301	301	300	1,503
Total	3,355	3,340	3,340	3,340	3,330	16,705
* ENERGY STAR® Water Heater Program (Residential)						
FEI	998	1,340	1,105	1,019	1,249	5,711
FEVI	99	133	109	101	124	565
Total	1,096	1,472	1,215	1,120	1,372	6,275
* New Home Program (Residential)						
FEI	943	943	943	714	714	4,256
FEVI	93	93	93	71	71	421
Total	1,036	1,036	1,036	784	784	4,677
* New Technologies Program (Residential)						
FEI	239	262	282	305	329	1,416
FEVI	24	26	28	30	32	140
Total	262	287	310	335	361	1,556
* Customer Engagement Tool for Conservation Behaviours (Residential)						
FEI	520	635	763	905	1,161	3,984
FEVI	58	71	85	101	129	444
Total	578	706	848	1,006	1,290	4,428
* Continuous Optimization Program (Commercial)						
FEI	2,655	2,085	1,645	1,322	1,081	8,789
FEVI	124	100	80	66	56	426
Total	2,779	2,185	1,724	1,389	1,137	9,214
ALL MTRC PROGRAMS						
FEI	8,408	8,304	7,778	7,305	7,563	39,357
FEVI	699	724	696	669	711	3,499
Total	**9,107**	**9,028**	**8,473**	**7,974**	**8,275**	**42,856**
ENTIRE PORTFOLIO						
FEI	30,505	32,453	31,733	31,308	31,868	157,867
FEVI	3,848	4,084	4,105	4,080	4,006	20,124
Total	**34,353**	**36,537**	**35,839**	**35,388**	**35,874**	**177,991**
MTRC VS. PORTFOLIO (%)						
FEI	28%	26%	25%	23%	24%	25%
FEVI	18%	18%	17%	16%	18%	17%
Total	**27%**	**25%**	**24%**	**23%**	**23%**	**24%**

* Program requires the MTRC in order to pass the economic screen

Exhibit 4 - Expenditures for Each of the Program Areas and the Total EEC Portfolio

Program Area and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Residential																		
FEI	6,815	7,260	7,074	6,759	7,140	35,048	2,655	2,760	2,919	2,902	3,149	14,385	9,469	10,020	9,993	9,661	10,290	49,433
FEVI	792	827	798	727	755	3,898	297	305	319	312	338	1,572	1,089	1,132	1,117	1,039	1,093	5,469
Total	7,606	8,086	7,872	7,486	7,895	38,945	2,952	3,065	3,238	3,214	3,488	15,957	10,558	11,152	11,110	10,700	11,383	54,902
Commercial																		
FEI	7,801	7,998	7,488	7,036	6,674	36,997	1,816	1,931	1,761	1,717	1,757	8,982	9,617	9,929	9,250	8,753	8,431	45,979
FEVI	1,247	1,357	1,445	1,389	1,335	6,773	268	287	277	274	285	1,391	1,515	1,644	1,722	1,663	1,620	8,165
Total	9,049	9,355	8,934	8,424	8,009	43,771	2,083	2,218	2,038	1,992	2,042	10,373	11,132	11,573	10,972	10,416	10,051	54,144
Industrial																		
FEI	1,173	1,531	1,748	1,990	1,964	8,406	565	610	671	718	744	3,309	1,738	2,142	2,419	2,708	2,709	11,715
FEVI	118	155	177	203	200	854	56	60	66	71	74	327	174	215	243	274	274	1,181
Total	1,291	1,686	1,925	2,193	2,165	9,260	621	671	737	789	818	3,636	1,912	2,357	2,662	2,983	2,983	12,896
Low Income																		
FEI	1,245	1,355	1,477	1,589	1,718	7,385	1,062	1,169	1,246	1,279	1,405	6,160	2,307	2,524	2,723	2,869	3,123	13,545
FEVI	154	165	177	188	201	886	168	134	142	190	158	792	322	299	319	378	360	1,678
Total	1,399	1,520	1,654	1,778	1,920	8,271	1,229	1,303	1,387	1,469	1,563	6,952	2,629	2,822	3,042	3,247	3,483	15,223
Conservation Education and Outreach																		
FEI	0	0	0	0	0	0	2,160	2,160	2,160	2,160	2,160	10,800	2,160	2,160	2,160	2,160	2,160	10,800
FEVI	0	0	0	0	0	0	240	240	240	240	240	1,200	240	240	240	240	240	1,200
Total	0	0	0	0	0	0	2,400	2,400	2,400	2,400	2,400	12,000	2,400	2,400	2,400	2,400	2,400	12,000
Innovative Technologies																		
FEI	178	394	595	524	566	2,257	928	721	572	606	618	3,445	1,106	1,115	1,167	1,130	1,183	5,702
FEVI	20	44	41	50	2	157	82	59	26	37	24	227	101	103	66	88	26	384
Total	198	438	636	574	568	2,414	1,009	780	597	644	642	3,672	1,207	1,218	1,233	1,218	1,210	6,086
Enabling Activities																		
FEI	0	0	0	0	0	0	4,109	4,564	4,022	4,027	3,972	20,693	4,109	4,564	4,022	4,027	3,972	20,693
FEVI	0	0	0	0	0	0	406	451	398	398	393	2,047	406	451	398	398	393	2,047
Total	0	0	0	0	0	0	4,515	5,015	4,420	4,425	4,365	22,740	4,515	5,015	4,420	4,425	4,365	22,740
ALL PROGRAMS																		
FEI	17,212	18,539	18,383	17,898	18,062	90,093	13,294	13,915	13,351	13,410	13,806	67,774	30,505	32,453	31,733	31,308	31,868	157,867
FEVI	2,331	2,547	2,638	2,557	2,494	12,567	1,516	1,537	1,468	1,523	1,512	7,556	3,848	4,084	4,105	4,080	4,006	20,124
Total	**19,543**	**21,086**	**21,020**	**20,455**	**20,556**	**102,660**	**14,810**	**15,452**	**14,818**	**14,933**	**15,318**	**75,331**	**34,353**	**36,537**	**35,839**	**35,388**	**35,874**	**177,991**

Exhibit 5 - Gas Savings and Cost-Effectiveness Results for Each of the Program Areas and the Total EEC Portfolio

Program Area and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios				
	2014	2015	2016	2017	2018		TRC	Portfolio*	Utility	Participant	RIM
Residential											
FEI	170,789	297,895	421,760	545,011	687,510	5,663,707	0.70	N/A	1.15	1.75	0.44
FEVI	19,465	33,895	47,914	61,335	76,726	642,736	0.77	N/A	1.17	2.85	0.31
Total	190,255	331,790	469,674	606,346	764,236	6,306,443	0.71	N/A	1.15	1.86	0.42
Commercial											
FEI	335,875	610,092	769,587	976,340	1,130,560	7,965,710	1.03	N/A	1.68	1.93	0.59
FEVI	31,919	62,488	96,253	127,165	156,203	1,413,496	1.21	N/A	1.75	3.63	0.38
Total	367,794	672,580	865,840	1,103,505	1,286,763	9,379,206	1.05	N/A	1.69	2.18	0.56
Industrial											
FEI	99,531	228,686	381,217	553,712	725,455	4,877,484	3.02	N/A	4.08	4.49	0.80
FEVI	10,134	23,327	38,969	56,774	74,496	510,708	3.11	N/A	4.21	7.65	0.49
Total	109,664	252,013	420,186	610,486	799,951	5,388,192	3.03	N/A	4.09	4.78	0.77
Low Income											
FEI	22,170	45,000	68,715	92,574	116,921	945,402	0.91	N/A	0.70	2.76	0.37
FEVI	4,188	8,277	12,308	16,218	20,062	148,396	1.14	N/A	0.86	5.27	0.29
Total	26,357	53,277	81,024	108,792	136,982	1,093,798	0.94	N/A	0.72	3.06	0.36
Conservation Education and Outreach											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Innovative Technologies											
FEI	8,891	73,874	92,309	97,560	126,973	1,242,290	1.70	N/A	2.23	4.24	0.65
FEVI	988	8,208	8,710	8,802	8,857	93,542	1.82	N/A	2.35	7.71	0.40
Total	9,878	82,082	101,019	106,362	135,830	1,335,832	1.71	N/A	2.23	4.45	0.63
Enabling Activities											
FEI	No Direct Savings						No Direct Savings				
FEVI											
Total											
ALL PROGRAMS											
FEI	637,255	1,255,547	1,733,589	2,265,196	2,787,418	20,694,592	0.92	1.31	1.29	2.15	0.51
FEVI	66,693	136,195	204,155	270,295	336,344	2,808,879	1.05	1.29	1.39	3.74	0.36
Total	**703,948**	**1,391,743**	**1,937,743**	**2,535,491**	**3,123,762**	**23,503,471**	**0.93**	**1.30**	**1.30**	**2.33**	**0.49**

* Includes the MTRC adder for programs that require it (i.e. TRC/MTRC hybrid)

3 Residential Energy Efficiency Program Area

3.1 Introduction

For 2014-2018, the suite of Residential Energy Efficiency Program Area customer offerings has been organized into the following programs grouped around the major Residential sector end uses. This allows the FEU to streamline communication and trade engagement strategies, and enhances customer targeting and messaging activities. These programs include:

Programs that focus on energy-efficient space heating, which include:
- Energy Efficient Home Performance program
- Furnace Replacement program
- Appliance Service program
- EnerChoice Fireplace program

Programs that focus on energy-efficient water heating and water conservation, which include:
- ENERGY STAR® Water Heater program
- Low-Flow Fixtures

Programs that focus on both energy-efficient space and water heating, which include:
- New Home program
- Financing Pilot
- Customer Engagement Tool for Conservation Behaviours, a program that was approved but not launched in 2012
- New Technologies program, a new program for 2014-2018, which has yet to be approved by the Commission

3.2 Selected Highlights

Collaborations with Utility Partners and Government

The longer term vision for residential programs is to continue to seek partnerships with electric utilities and governments. This will allow us to build a common rebate administration and marketing platform that will enable customers and trades to have greater access to rebate and energy literacy programs.[4]

Space Heating

Space heating programs provide a range of customer options that include building envelope measures, furnaces, appliance servicing and fireplaces.

- The FEU intends to continue its collaboration with utility partners and government in support of an Energy Efficient Home Performance program that includes building envelope measures and the promotion of deeper home energy retrofits.

- The Furnace Replacement program, which encourages the early replacement of standard and mid-efficiency furnaces, will run outside the heating season to reduce the incidence of emergency replacement. An Appliance Service program, running in tandem with the furnace program, engages contractors in efficiency dialogues with their customers. This will result in the promotion of energy-efficient appliance upgrades for several programs.

[4] It should be noted that at the time of writing this report, the future of a government-utility partnership, such as LiveSmart BC, was uncertain.

- The EnerChoice Fireplace program will continue to operate in its current form, keeping close ties to the fireplace industry to ensure that efficiency testing protocols are being followed. This program will also help raise the EnerChoice energy-efficiency standard over time.

Water Heating

Water heating programs also provide a range of customer options that include both water heaters and water using fixtures:

- The ENERGY STAR® Water Heater program will promote the adoption and market transformation of efficient water heaters and will prepare the market for upcoming energy-efficiency standards and regulations. FEU will limit investment in ENERGY STAR® washers to short term promotions since the washer market has matured such that there is reduced opportunity to capture natural gas savings. Supporting market transformation of water heaters is considered a higher priority.

- Low-flow water saving fixtures offer a low-cost market opportunity for additional savings. FEU will partner with MURBs and communities to promote this program.

Programs focused on both space heating and water heating

A number of programs provide a range of customer options that serve both space and water heating:

- The New Home program, which will be implemented in collaboration with electric utilities, will focus on upgrades to achieve increased home performance ratings and support pending changes to the National Building Code. Natural Resources Canada (NRCan) will be introducing a new Home Energy Rating system in 2014. As such, future program design is under development. In addition to home performance measures, builders and developers can participate in other appliance programs to ensure that the most energy-efficient natural gas appliances (space and water heating) are installed.

- The Financing program provides customer access to financing, both utility-funded on-bill financing and financing through third-party financial institutions. Both on-bill financing and financing through third-party financial institutions will require interest rate buy-downs and incur administration costs. In the case of on-bill financing, most promotion is anticipated to be through contractors. In the case of financial institution partnerships, most promotion will be undertaken by the financial institution. Comprehensive program design and cost-benefit analysis will be conducted based on the success of the pilots in the coming years.

- The Customer Engagement Tool will provide home energy reporting and other tools that foster conservation behaviours. It will also provide a platform for promoting incentives and other offers. The FEU is considering a pilot in the Shared Service Territory in 2013. Subsequently, the pilot results will be evaluated for potential large scale rollout in 2014.

- The New Technologies program, a new initiative not yet approved by the Commission, will allow Residential sector customers the opportunity to install leading edge appliances identified in the Innovative Technologies program area. The exact details of this program are still under development.

3.3 Overview of Results

Exhibit 6 and Exhibit 7 provides a summary of the estimated savings, program expenditures and cost-effectiveness results for each of the programs noted above and for the Residential Energy Efficiency Program Area as a whole.

Exhibit 6 - Summary of Expenditures for the Residential Sector Program Portfolio

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Energy Efficient Home Performance Program																		
FEI	869	969	994	1,118	1,242	5,192	410	385	410	385	410	1,998	1,279	1,354	1,403	1,503	1,652	7,190
FEVI	86	96	98	111	123	513	41	38	41	38	41	198	126	134	139	149	163	711
Total	955	1,065	1,092	1,228	1,365	5,705	450	423	450	423	450	2,196	1,405	1,488	1,542	1,651	1,815	7,901
* Furnace Replacement Program																		
FEI	2,715	2,715	2,715	2,715	2,715	13,577	338	324	324	324	314	1,625	3,053	3,040	3,040	3,040	3,030	15,202
FEVI	269	269	269	269	269	1,343	33	32	32	32	31	161	302	301	301	301	300	1,503
Total	2,984	2,984	2,984	2,984	2,984	14,920	371	356	356	356	346	1,785	3,355	3,340	3,340	3,340	3,330	16,705
Enerchoice Fireplace Program																		
FEI	887	843	798	532	488	3,548	269	260	253	198	189	1,168	1,156	1,103	1,051	730	677	4,716
FEVI	208	198	187	125	114	832	63	61	59	46	44	274	271	259	247	171	159	1,106
Total	1,095	1,040	986	657	602	4,380	332	321	312	244	233	1,443	1,427	1,361	1,298	901	835	5,823
Appliance Service Program																		
FEI	324	324	324	324	324	1,621	91	91	91	91	91	455	415	415	415	415	415	2,076
FEVI	32	32	32	32	32	160	9	9	9	9	9	45	41	41	41	41	41	205
Total	356	356	356	356	356	1,781	100	100	100	100	100	500	456	456	456	456	456	2,281
* ENERGY STAR® Water Heater Program																		
FEI	874	1,232	981	933	1,157	5,176	123	108	125	86	92	535	998	1,340	1,105	1,019	1,249	5,711
FEVI	86	122	97	92	114	512	12	11	12	9	9	53	99	133	109	101	124	565
Total	961	1,353	1,078	1,025	1,271	5,688	136	119	137	95	101	588	1,096	1,472	1,215	1,120	1,372	6,275
Low-Flow Fixtures																		
FEI	173	173	173	173	173	865	91	91	91	91	91	455	264	264	264	264	264	1,320
FEVI	17	17	17	17	17	86	9	9	9	9	9	45	26	26	26	26	26	131
Total	190	190	190	190	190	950	100	100	100	100	100	500	290	290	290	290	290	1,450
* New Home Program																		
FEI	772	772	772	606	606	3,527	171	171	171	108	108	729	943	943	943	714	714	4,256
FEVI	76	76	76	60	60	349	17	17	17	11	11	72	93	93	93	71	71	421
Total	848	848	848	666	666	3,876	188	188	188	118	118	801	1,036	1,036	1,036	784	784	4,677

* Program requires the MTRC in order to pass the economic screen

Summary of Expenditures for the Residential Sector Program Portfolio (cont'd…)

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
* New Technologies Program																		
FEI	174	174	215	215	259	1,037	65	88	67	90	69	379	239	262	282	305	329	1,416
FEVI	17	17	21	21	26	103	6	9	7	9	7	37	24	26	28	30	32	140
Total	191	191	237	237	285	1,140	71	97	74	99	76	416	262	287	310	335	361	1,556
* Customer Engagement Tool for Conservation Behaviours																		
FEI	0	0	0	0	0	0	520	635	763	905	1,161	3,984	520	635	763	905	1,161	3,984
FEVI	0	0	0	0	0	0	58	71	85	101	129	444	58	71	85	101	129	444
Total	0	0	0	0	0	0	578	706	848	1,006	1,290	4,428	578	706	848	1,006	1,290	4,428
Financing Pilot																		
FEI	26	59	102	143	176	505	86	115	133	133	133	600	112	174	235	276	309	1,105
Non-Program Specific Expenses																		
FEI	0	0	0	0	0	0	491	491	491	491	491	2,457	491	491	491	491	491	2,457
FEVI	0	0	0	0	0	0	49	49	49	49	49	243	49	49	49	49	49	243
Total	0	0	0	0	0	0	540	540	540	540	540	2,700	540	540	540	540	540	2,700
ALL PROGRAMS																		
FEI	6,815	7,260	7,074	6,759	7,140	35,048	2,655	2,760	2,919	2,902	3,149	14,385	9,469	10,020	9,993	9,661	10,290	49,433
FEVI	792	827	798	727	755	3,898	297	305	319	312	338	1,572	1,089	1,132	1,117	1,039	1,093	5,469
Total	**7,606**	**8,086**	**7,872**	**7,486**	**7,895**	**38,945**	**2,952**	**3,065**	**3,238**	**3,214**	**3,488**	**15,957**	**10,558**	**11,152**	**11,110**	**10,700**	**11,383**	**54,902**

* Program requires the MTRC in order to pass the economic screen

Exhibit 7 - Summary of Savings and Cost-Effectiveness Results for the Residential Sector Program Portfolio

Program and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios				
	2014	2015	2016	2017	2018		TRC	MTRC	Utility	Participant	RIM
Energy Efficient Home Performance Program											
FEI	33,358	70,528	108,651	151,540	199,194	1,990,386	1.06	N/A	2.87	2.07	0.57
FEVI	3,299	6,975	10,746	14,987	19,701	202,066	1.09	N/A	2.94	3.27	0.37
Total	36,657	77,503	119,397	166,528	218,895	2,192,452	1.07	N/A	2.88	2.18	0.55
* Furnace Replacement Program											
FEI	28,586	57,171	85,476	113,781	141,345	1,356,361	0.50	1.41	0.90	1.28	0.40
FEVI	2,827	5,654	8,454	11,253	13,979	137,396	0.51	1.44	0.92	1.81	0.29
Total	31,413	62,826	93,930	125,034	155,325	1,493,756	0.50	1.41	0.90	1.33	0.39
Enerchoice Fireplace Program											
FEI	13,203	25,746	37,628	45,550	52,811	466,952	1.54	N/A	0.96	5.50	0.41
FEVI	3,097	6,039	8,826	10,685	12,388	111,792	1.57	N/A	0.97	8.10	0.29
Total	16,300	31,785	46,455	56,234	65,199	578,744	1.55	N/A	0.96	5.99	0.38
Appliance Service Program											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
* ENERGY STAR® Water Heater Program											
FEI	10,931	26,326	38,153	49,496	63,560	612,197	0.62	1.76	1.09	1.45	0.43
FEVI	1,081	2,604	3,773	4,895	6,286	62,066	0.64	1.80	1.12	2.11	0.31
Total	12,012	28,930	41,927	54,391	69,847	674,263	0.63	1.77	1.10	1.51	0.42
Low-Flow Fixtures											
FEI	11,671	23,342	35,012	46,683	58,354	388,690	3.00	N/A	2.80	8.00	0.56
FEVI	1,154	2,309	3,463	4,617	5,771	39,068	3.03	N/A	2.83	12.67	0.37
Total	12,825	25,650	38,475	51,300	64,125	427,758	3.00	N/A	2.81	8.42	0.54
* New Home Program											
FEI	7,596	15,191	22,787	29,449	36,110	399,748	0.40	1.12	0.98	0.95	0.41
FEVI	751	1,502	2,254	2,913	3,571	40,694	0.41	1.15	1.00	1.39	0.30
Total	8,347	16,694	25,041	32,361	39,682	440,443	0.40	1.12	0.98	0.99	0.40
* New Technologies Program											
FEI	1,321	2,641	4,277	5,913	7,884	51,813	0.37	1.04	0.35	1.75	0.24
FEVI	131	261	423	585	780	5,211	0.37	1.05	0.36	2.25	0.19
Total	1,451	2,902	4,700	6,498	8,664	57,024	0.37	1.04	0.35	1.79	0.23
* Customer Engagement Tool for Conservation Behaviours											
FEI	64,125	76,950	89,775	102,600	128,250	397,559	0.86	2.56	0.86	N/A	0.37
FEVI	7,125	8,550	9,975	11,400	14,250	44,444	0.85	2.55	0.85	N/A	0.27
Total	71,250	85,500	99,750	114,000	142,500	442,003	0.86	2.56	0.86	N/A	0.36
Financing Pilot											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	1.00	0.00
Non-Program Specific Expenses											
FEI											
FEVI	No Direct Savings						No Direct Savings				
Total											
ALL PROGRAMS											
FEI	170,789	297,895	421,760	545,011	687,510	5,663,707	0.70	N/A	1.15	1.75	0.44
FEVI	19,465	33,895	47,914	61,335	76,726	642,736	0.77	N/A	1.17	2.85	0.31
Total	**190,255**	**331,790**	**469,674**	**606,346**	**764,236**	**6,306,443**	**0.71**	N/A	**1.15**	**1.86**	**0.42**

* Program requires the MTRC in order to pass the economic screen

3.4 Program Profiles

The following pages provide profiles for each of the programs shown above in Exhibit 6 and Exhibit 7.

3.4.1 Energy Efficient Home Performance Program

Program Description	This program will promote energy-efficiency home retrofits in collaboration with utility partners as well as provincial, federal and municipal governments. In addition to incentives, initiatives include capacity building for weatherization and educational opportunities to promote the new Home Energy Rating System.	
Target Market	Residential	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Air Sealing and Draft Proofing (25%), Attic Insulation (40%), Basement Insulation (12%), Wall Insulation (13%), Champion Bonus (10%)	
Partners	BC Hydro, PowerSense, Municipal, Provincial and Federal Government (i.e. applies to all measures except the Champion Bonus)	
Incremental Cost ($)	$1,130	Air Sealing and Draft Proofing: $774, Attic Insulation: $1,153, Basement Insulation: $1,008, Wall Insulation: $1,188, Champion Bonus: $2,000 ***Sources:*** Dunsky Energy Consulting, HOT2000 Modeling
Incentive Amount, FortisBC ($)	$324	Air Sealing and Draft Proofing: $297, Attic Insulation: $268, Basement Insulation: $346, Wall Insulation: $400, Champion Bonus: $500
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	13.0	Air Sealing and Draft Proofing: 7.3 GJ, Attic Insulation: 13.3 GJ, Basement Insulation: 10.7 GJ, Wall Insulation: 23.6 GJ, Champion Bonus: 15.0 GJ ***Sources:*** Dunsky Energy Consulting, HOT2000 modeling, 2010. Conservation Potential Review.
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	20.0	Air Sealing and Draft Proofing: 20 yrs, Attic Insulation: 20 yrs, Basement Insulation: 20 yrs, Wall Insulation: 20 yrs, Champion Bonus: 20 yrs ***Source:*** 2010 Conservation Potential Review.
Free Rider Rate (%)	19%	Air Sealing and Draft Proofing: 20%, Attic Insulation: 20%, Basement Insulation: 20%, Wall Insulation: 20%, Champion Bonus: 10% ***Source:*** BC Hydro
Spillover Rate (%)	15%	***Source:*** Based on preliminary indication of spillover in BC Hydro LiveSmart BC Evaluation 2012

Energy Efficient Home Performance Program (cont'd…)

	Service Region	2014	2015	2016	2017	2018
Participants	**FEI**	2,646	2,948	3,024	3,402	3,780
	FEVI	265	295	302	340	378
	FEW	29	33	34	38	42
	Total	2,940	3,276	3,360	3,780	4,200

	Service Region	Incentives	Admin	Comm.	Evaluation	Total
Expenditures ($000's)				**2014**		
	FEI	$860	$138	$134	$134	$1,265
	FEVI	$86	$14	$13	$13	$126
	FEW	$10	$2	$1	$1	$14
	Total	$955	$153	$149	$149	$1,405
				2015		
	FEI	$958	$133	$133	$114	$1,339
	FEVI	$96	$13	$13	$11	$134
	FEW	$11	$1	$1	$1	$15
	Total	$1,065	$148	$148	$127	$1,488
				2016		
	FEI	$983	$138	$134	$134	$1,388
	FEVI	$98	$14	$13	$13	$139
	FEW	$11	$2	$1	$1	$15
	Total	$1,092	$153	$149	$149	$1,542
				2017		
	FEI	$1,106	$133	$133	$114	$1,486
	FEVI	$111	$13	$13	$11	$149
	FEW	$12	$1	$1	$1	$17
	Total	$1,228	$148	$148	$127	$1,651
				2018		
	FEI	$1,228	$138	$134	$134	$1,633
	FEVI	$123	$14	$13	$13	$163
	FEW	$14	$2	$1	$1	$18
	Total	$1,365	$153	$149	$149	$1,815
	Grand Total	**$5,705**	**$755**	**$742**	**$699**	**$7,901**

3.4.2 Furnace Replacement Program

Program Description	This program will target customers with functioning furnaces (standard or mid-efficiency) or boilers and, through a combination of marketing and incentives, will encourage them to replace the equipment now, rather than waiting for it to fail at some point in the future.	
Target Market	Residential	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Standard Efficiency furnace (79%), Mid-Efficiency furnace (18%), Boilers (3%)	
Partners	N/A	
Incremental Cost ($)	$1,652	Standard Efficiency Furnace: $1,597, Mid-Efficiency furnace: $1,597 Boilers: $3,315 The economic cost of the furnace or boiler is not the direct cost paid by the homeowner, but is the direct cost less the NPV of the cost of the furnace that would have been installed in the future. ***Sources:*** FortisBC Furnace Replacement Pilot Program Evaluation. Habart Consulting, April 2013
Incentive Amount, FortisBC ($)	$800	Standard Efficiency furnace: $800, Mid-Efficiency furnace: $800, Boilers: $800
Contractor Incentive, FortisBC ($)	$50	Standard Efficiency furnace: $50, Mid-Efficiency furnace: $50, Boilers: $50
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	9.1	Standard Efficiency furnace: 10 GJ, Mid-Efficiency furnace: 5.5 GJ, Boilers: 8.8 GJ ***Sources:*** FortisBC Furnace Replacement Pilot Program Evaluation. Habart Consulting, April 2013 and Sampson and Habart, 2007-2008 Furnace Program Evaluation
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	18.0	Standard Efficiency furnace: 18 yrs, Mid-Efficiency furnace: 18 yrs, Boilers: 18 yrs ***Sources:*** Navigant Consulting report, BC Hydro Power Smart QA Standard, NRCan
Free Rider Rate (%)	8%	Standard Efficiency furnace: 8%, Mid-Efficiency furnace: 8%, Boilers: 8% ***Sources:*** FortisBC Furnace Replacement Pilot Program Evaluation. Habart Consulting, April 2013
Spillover Rate (%)	0%	

Furnace Replacement Program (cont'd…)

Participants	**Service Region**	**2014**	**2015**	**2016**	**2017**	**2018**
	FEI	3,357	3,357	3,357	3,357	3,357
	FEVI	336	336	336	336	336
	FEW	37	37	37	37	37
	Total	3,730	3,730	3,730	3,730	3,730
Expenditures ($000's)	**Service Region**	**Incentives**	**Admin**	**Comm.**	**Evaluation**	**Total**
	2014					
	FEI	$2,686	$222	$44	$68	$3,020
	FEVI	$269	$22	$4	$7	$302
	FEW	$30	$2	$0	$1	$34
	Total	$2,984	$247	$49	$75	$3,355
	2015					
	FEI	$2,686	$222	$44	$54	$3,006
	FEVI	$269	$22	$4	$5	$301
	FEW	$30	$2	$0	$1	$33
	Total	$2,984	$247	$49	$60	$3,340
	2016					
	FEI	$2,686	$222	$44	$54	$3,006
	FEVI	$269	$22	$4	$5	$301
	FEW	$30	$2	$0	$1	$33
	Total	$2,984	$247	$49	$60	$3,340
	2017					
	FEI	$2,686	$222	$44	$54	$3,006
	FEVI	$269	$22	$4	$5	$301
	FEW	$30	$2	$0	$1	$33
	Total	$2,984	$247	$49	$60	$3,340
	2018					
	FEI	$2,686	$222	$44	$44	$2,997
	FEVI	$269	$22	$4	$4	$300
	FEW	$30	$2	$0	$0	$33
	Total	$2,984	$247	$49	$49	$3,330
	Grand Total	**$14,920**	**$1,235**	**$246**	**$304**	**$16,705**

Notes:
1. Contractor Incentive is included in the Admin portion of expenditures

3.4.3 EnerChoice Fireplace Program

Program Description	This program will promote the purchase and installation of energy-efficient EnerChoice fireplaces. The program will emphasize consumer and dealer education about the importance of selecting natural gas fireplaces based on energy-efficient performance attributes rather than just decorative features. Program awareness and participation will be promoted through a combination of customer and dealer incentives.	
Target Market	Residential	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	EnerChoice Fireplace (Retrofit) (75%), EnerChoice Fireplace (New Construction) (25%)	
Partners	N/A	
Incremental Cost ($)	$188	EnerChoice Fireplace (Retrofit): $150, EnerChoice Fireplace (New Construction): $300 ***Sources:*** Hearth Manufacturers and Hearth Patio and Barbeque Association (HPBAC)
Incentive Amount, FortisBC ($)	$300	EnerChoice Fireplace (Retrofit): $300, EnerChoice Fireplace (New Construction): $300
Contractor Incentive, FortisBC ($)	$38	EnerChoice Fireplace (Retrofit): $50, EnerChoice Fireplace (New Construction): $0
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	5.8	EnerChoice Fireplace (Retrofit): 5.8 GJ, EnerChoice Fireplace (New Construction): 5.8 GJ ***Sources:*** Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates, 2010 Conservation Potential Review
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	15.0	EnerChoice Fireplace (Retrofit): 15 yrs, EnerChoice Fireplace (New Construction): 15 yrs ***Sources:*** Data from prior program participants, Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates, 2010 Conservation Potential Review
Free Rider Rate (%)	21%	EnerChoice Fireplace (Retrofit): 26%, EnerChoice Fireplace (New Construction): 13% ***Sources:*** Data from prior program participants, Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates, 2010 Conservation Potential Review
Spillover Rate (%)	0%	

EnerChoice Fireplace Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	2,920	2,774	2,628	1,752	1,606
FEVI	694	659	624	416	381
FEW	37	35	33	22	20
Total	3,650	3,468	3,285	2,190	2,008

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$876	$145	$80	$41	$1,142
FEVI	$208	$35	$19	$10	$271
FEW	$11	$2	$1	$1	$14
Total	$1,095	$182	$99	$51	$1,427
2015					
FEI	$832	$138	$79	$40	$1,089
FEVI	$198	$33	$19	$9	$259
FEW	$10	$2	$1	$0	$14
Total	$1,040	$172	$99	$50	$1,361
2016					
FEI	$788	$130	$80	$39	$1,038
FEVI	$187	$31	$19	$9	$247
FEW	$10	$2	$1	$0	$13
Total	$986	$163	$100	$49	$1,298
2017					
FEI	$526	$94	$61	$40	$721
FEVI	$125	$22	$14	$10	$171
FEW	$7	$1	$1	$1	$9
Total	$657	$118	$76	$50	$901
2018					
FEI	$482	$87	$59	$40	$668
FEVI	$114	$21	$14	$10	$159
FEW	$6	$1	$1	$1	$8
Total	$602	$108	$74	$51	$835
Grand Total	**$4,380**	**$743**	**$449**	**$250**	**$5,823**

Notes:

1. Contractor Incentive is included in the Admin portion of expenditures

3.4.4 Appliance Service Program

Program Description	This program will provide customer education related to the importance of regular appliance maintenance to ensure efficient operation of natural gas appliances. This program will also create opportunities for contractors to dialogue with customers about upgrading appliances to more efficient models.	
Target Market	Residential	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Furnace Service (71%), Fireplace Service (29%)	
Partners	N/A	
Incremental Cost ($)	N/A	
Incentive Amount, FortisBC ($)	$25	Furnace Service: $25, Fireplace Service: $25
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	0.0	
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	N/A	Not applicable
Free Rider Rate (%)	N/A	
Spillover Rate (%)	N/A	

Appliance Service Program (cont'd…)

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	12,825	12,825	12,825	12,825	12,825
	FEVI	1,283	1,283	1,283	1,283	1,283
	FEW	143	143	143	143	143
	Total	14,250	14,250	14,250	14,250	14,250

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$321	$49	$23	$18	$411
	FEVI	$32	$5	$2	$2	$41
	FEW	$4	$1	$0	$0	$5
	Total	$356	$54	$26	$20	$456
	2015					
	FEI	$321	$49	$23	$18	$411
	FEVI	$32	$5	$2	$2	$41
	FEW	$4	$1	$0	$0	$5
	Total	$356	$54	$26	$20	$456
	2016					
	FEI	$321	$49	$23	$18	$411
	FEVI	$32	$5	$2	$2	$41
	FEW	$4	$1	$0	$0	$5
	Total	$356	$54	$26	$20	$456
	2017					
	FEI	$321	$49	$23	$18	$411
	FEVI	$32	$5	$2	$2	$41
	FEW	$4	$1	$0	$0	$5
	Total	$356	$54	$26	$20	$456
	2018					
	FEI	$321	$49	$23	$18	$411
	FEVI	$32	$5	$2	$2	$41
	FEW	$4	$1	$0	$0	$5
	Total	$356	$54	$26	$20	$456
	Grand Total	**$1,781**	**$270**	**$130**	**$100**	**$2,281**

3.4.5 ENERGY STAR® Water Heater Program

Program Description	This program promotes the replacement of standard efficiency water heaters with efficient ENERGY STAR® models. As part of a longer term market transformation strategy, the program will introduce 0.67 EF storage tank water heaters and new technologies with energy factors (EF) greater than 0.80. The new technologies include condensing and non-condensing tankless water heaters, hybrids and condensing storage tanks. The program is available to both retrofit and new construction markets. The program supports upcoming federal and provincial Efficiency Act Standards for natural gas- and propane-fired water heaters.	
Target Market	Residential	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	ENERGY STAR® 0.67 EF Storage Tank (51%), Non-Condensing Tankless (10%), Condensing Tankless (31%), Hybrids (6%), Condensing Storage Tanks (2%)	
Partners	N/A	
Incremental Cost ($)	$872	ENERGY STAR® 0.67 EF Storage Tank: $222, Non-Condensing Tankless: $768, Condensing Tankless: $1,136, Hybrids: $1,580, Condensing Storage Tanks: $2,724 ***Sources:*** Manufacturers and other utilities; ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; Canadian Residential Water Heater Market Assessment. 2009. Caneta Research Inc. Residential High-Efficiency Water Heater Pilot. Program participant feedback
Incentive Amount, FortisBC ($)	$401	ENERGY STAR® 0.67 EF Storage Tank: $200, Non-Condensing Tankless: $400, Condensing Tankless: $500, Hybrids: $500, Condensing Storage Tanks: $1,000
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	5.8	ENERGY STAR® 0.67 EF Storage Tank: 3 GJ, Non-Condensing Tankless: 7.2 GJ, Condensing Tankless: 7.9 GJ, Hybrids: 6.7 GJ, Condensing Storage Tanks: 4.2 GJ ***Sources:*** Manufacturers and other utilities; ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; Canadian Residential Water Heater Market Assessment. 2009. Caneta Research Inc. Residential High-Efficiency Water Heater Pilot
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	17.2	ENERGY STAR® 0.67 EF Storage Tank: 13 yrs, Non-Condensing Tankless: 20 yrs, Condensing Tankless: 20 yrs, Hybrids: 20 yrs, Condensing Storage Tanks: 13 yrs ***Sources:*** Manufacturers and other utilities; ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; Canadian Residential Water Heater Market Assessment. 2009. Caneta Research Inc.
Free Rider Rate (%)	10%	ENERGY STAR® 0.67 EF Storage Tank: 10%, Non-Condensing Tankless: 10%, Condensing Tankless: 10%, Hybrids: 10%, Condensing Storage Tanks: 10% ***Sources:*** ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Sachs, H., Jacob Talbot and Nate Kaufman; Program Participant Feedback. Residential High-Efficiency Water Heater Pilot
Spillover Rate (%)	0%	

ENERGY STAR® Water Heater Program (cont'd…)

	Service Region	2014	2015	2016	2017	2018
Participants	**FEI**	2,492	3,510	2,843	1,755	2,176
	FEVI	249	351	284	176	218
	FEW	28	39	32	20	24
	Total	2,769	3,900	3,159	1,950	2,418

	Service Region	Incentives	Admin	Comm.	Evaluation	Total
Expenditures ($000's)				**2014**		
	FEI	$865	$32	$45	$45	$987
	FEVI	$86	$3	$5	$5	$99
	FEW	$10	$0	$1	$1	$11
	Total	$961	$35	$50	$50	$1,096
				2015		
	FEI	$1,218	$44	$45	$18	$1,325
	FEVI	$122	$4	$5	$2	$133
	FEW	$14	$0	$1	$0	$15
	Total	$1,353	$49	$50	$20	$1,472
				2016		
	FEI	$970	$33	$45	$45	$1,093
	FEVI	$97	$3	$5	$5	$109
	FEW	$11	$0	$1	$1	$12
	Total	$1,078	$37	$50	$50	$1,215
				2017		
	FEI	$923	$22	$45	$18	$1,008
	FEVI	$92	$2	$5	$2	$101
	FEW	$10	$0	$1	$0	$11
	Total	$1,025	$25	$50	$20	$1,120
				2018		
	FEI	$1,144	$27	$46	$18	$1,235
	FEVI	$114	$3	$5	$2	$124
	FEW	$13	$0	$1	$0	$14
	Total	$1,271	$30	$51	$20	$1,372
	Grand Total	**$5,688**	**$176**	**$251**	**$161**	**$6,275**

3.4.6 Low-Flow Fixtures

Program Description	This program will develop partnership opportunities that promote the installation of low-flow fixtures that reduce hot water consumption in houses, row houses and MURBS.	
Target Market	Residential	
New vs. Retrofit	Retrofit	
Eligible Measures	Low-Flow Fixtures	
Partners	Non-Governmental Organizations (NGOs) and Municipalities	
Incremental Cost ($)	$20	***Source:*** 2010 Conservation Potential Review
Incentive Amount, FortisBC ($)	$20	***Source:*** 2010 Conservation Potential Review
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	1.5	***Sources:*** 2010 Conservation Potential Review. City Green Report: Tap by Tap showed base GPM to be approximately 3.73 as opposed to 2 GPM base noted in 2010 CPR. Resulting 2.48 GPM savings may indicate higher GJ savings.
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	10.0	***Source:*** 2010 Conservation Potential Review (ultra low-flow shower head, 1.25 GPM)
Free Rider Rate (%)	10%	***Source:*** City Green Report: Tap by Tap, January 10, 2012
Spillover Rate (%)	0%	

Low-Flow Fixtures (cont'd…)

	Service Region	2014	2015	2016	2017	2018
Participants	**FEI**	8,550	8,550	8,550	8,550	8,550
	FEVI	855	855	855	855	855
	FEW	95	95	95	95	95
	Total	9,500	9,500	9,500	9,500	9,500

	Service Region	Incentives	Admin	Comm.	Evaluation	Total
Expenditures ($000's)				**2014**		
	FEI	$171	$36	$45	$9	$261
	FEVI	$17	$4	$5	$1	$26
	FEW	$2	$0	$1	$0	$3
	Total	$190	$40	$50	$10	$290
				2015		
	FEI	$171	$36	$45	$9	$261
	FEVI	$17	$4	$5	$1	$26
	FEW	$2	$0	$1	$0	$3
	Total	$190	$40	$50	$10	$290
				2016		
	FEI	$171	$36	$45	$9	$261
	FEVI	$17	$4	$5	$1	$26
	FEW	$2	$0	$1	$0	$3
	Total	$190	$40	$50	$10	$290
				2017		
	FEI	$171	$36	$45	$9	$261
	FEVI	$17	$4	$5	$1	$26
	FEW	$2	$0	$1	$0	$3
	Total	$190	$40	$50	$10	$290
				2018		
	FEI	$171	$36	$45	$9	$261
	FEVI	$17	$4	$5	$1	$26
	FEW	$2	$0	$1	$0	$3
	Total	$190	$40	$50	$10	$290
	Grand Total	**$950**	**$200**	**$250**	**$50**	**$1,450**

3.4.7 New Home Program

Program Description	This program will provide education and financial incentives in support of energy-efficient building practices for the Residential sector. This program supports the pending efficiency updates to the BC Building Code (2013) and also educates consumers about the benefits of purchasing energy-efficient new homes. The Companies are collaborating with the BC Hydro Power Smart New Home and FortisBC PowerSense programs. Future program design is under development, pending the outcome of Building Code efficiency upgrade announcements and the introduction of new Home Energy Rating Systems, including NRCan's EnerGuide revisions, R2000, and ENERGY STAR® for New Homes.	
Target Market	Builders of residential single family homes and townhomes	
New vs. Retrofit	New Construction	
Eligible Measures (% Distribution of Participants)	SFD-Home Performance Rating (25%), Townhouse-Home Performance Rating (63%), Condensing Boiler (12%)	
Partners	BC Hydro (i.e. applies to all measures except the Condensing Boilers)	
Incremental Cost ($)	$1,787	SFD-Home Performance Rating: $5,933, Townhouse-Home Performance Rating: $200, Condensing Boiler: $1,275 ***Sources:*** New Construction Costs and Savings and Life Cycle Costs, 2011, Cooper and Habart, and Dunsky Energy Consulting
Incentive Amount, FortisBC ($)	$536	SFD-Home Performance Rating: $1,500, Townhouse-Home Performance Rating: $100, Condensing Boiler: $1,000
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$197	SFD-Home Performance Rating: $500, Townhouse-Home Performance Rating: $100, Condensing Boiler: $0 BC Hydro Incentives not included in expenditures since electricity savings have been ignored
Gas Savings per Participant (GJ/yr)	6.6	SFD-Home Performance Rating: 16.3 GJ, Townhouse-Home Performance Rating: 2.6 GJ, Condensing Boiler: 8.4 GJ ***Sources:*** New Construction Costs and Savings and Life Cycle Costs, 2011, Cooper and Habart, and Dunsky Energy Consulting
Elec. Savings per Participant (kWh/yr)	0	Electricity savings ignored since these savings are being credited to BC Hydro
Measure Life (years)	24.5	SFD-Home Performance Rating: 25 yrs, Townhouse-Home Performance Rating: 25 yrs, Condensing Boiler: 18 yrs ***Sources:*** New Construction Costs and Savings and Life Cycle Costs, 2011, Cooper and Habart, and Dunsky Energy Consulting
Free Rider Rate (%)	12%	SFD-Home Performance Rating: 10%, Townhouse-Home Performance Rating: 10%, Condensing Boiler: 33%
Spillover Rate (%)	0%	

New Home Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	1,368	1,368	1,368	1,204	1,204
FEVI	137	137	137	120	120
FEW	15	15	15	13	13
Total	1,520	1,520	1,520	1,338	1,338

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$763	$19	$100	$51	$933
FEVI	$76	$2	$10	$5	$93
FEW	$8	$0	$1	$1	$10
Total	$848	$21	$111	$56	$1,036
2015					
FEI	$763	$34	$85	$51	$933
FEVI	$76	$3	$8	$5	$93
FEW	$8	$0	$1	$1	$10
Total	$848	$38	$94	$56	$1,036
2016					
FEI	$763	$34	$85	$51	$933
FEVI	$76	$3	$8	$5	$93
FEW	$8	$0	$1	$1	$10
Total	$848	$38	$94	$56	$1,036
2017					
FEI	$599	$12	$63	$32	$706
FEVI	$60	$1	$6	$3	$71
FEW	$7	$0	$1	$0	$8
Total	$666	$13	$70	$36	$784
2018					
FEI	$599	$12	$63	$32	$706
FEVI	$60	$1	$6	$3	$71
FEW	$7	$0	$1	$0	$8
Total	$666	$13	$70	$36	$784
Grand Total	**$3,876**	**$122**	**$439**	**$240**	**$4,677**

3.4.8 New Technologies Program

Program Description	This program will operate in conjunction with the Innovative Technologies Program (see Section 8). by introducing technologies that are cost effective but with initially low market penetration. Market adoption will be increased by educating the trades and consumers about the potential of the new energy-saving technologies.	
Target Market	Residential	
New vs. Retrofit	Both	
Eligible Measures	New Technologies	
Partners	N/A	
Incremental Cost ($)	$2,000	These new technologies will be transferred from Innovative Technologies. Assumptions will be derived from the pilot information available at that time. Placeholders are included for the purposes of cost-effectiveness modeling but are subject to change.
Incentive Amount, FortisBC ($)	$1,000	
Contractor Incentive, FortisBC ($)	$50	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	8.0	
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	10.0	
Free Rider Rate (%)	5%	
Spillover Rate (%)	0%	

New Technologies Program (cont'd…)

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	172	172	213	213	257
	FEVI	17	17	21	21	26
	FEW	2	2	2	2	3
	Total	191	191	237	237	285

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
				2014		
	FEI	$172	$20	$22	$22	$236
	FEVI	$17	$2	$2	$2	$24
	FEW	$2	$0	$0	$0	$3
	Total	$191	$22	$25	$25	$262
				2015		
	FEI	$172	$20	$23	$45	$259
	FEVI	$17	$2	$2	$4	$26
	FEW	$2	$0	$0	$0	$3
	Total	$191	$22	$25	$50	$287
				2016		
	FEI	$213	$22	$22	$22	$279
	FEVI	$21	$2	$2	$2	$28
	FEW	$2	$0	$0	$0	$3
	Total	$237	$24	$25	$25	$310
				2017		
	FEI	$213	$22	$23	$45	$302
	FEVI	$21	$2	$2	$4	$30
	FEW	$2	$0	$0	$0	$3
	Total	$237	$24	$25	$50	$335
				2018		
	FEI	$257	$24	$22	$22	$325
	FEVI	$26	$2	$2	$2	$32
	FEW	$3	$0	$0	$0	$4
	Total	$285	$27	$25	$25	$361
	Grand Total	**$1,140**	**$118**	**$125**	**$173**	**$1,556**

Notes:
1. Contractor Incentive is included in the Admin portion of expenditures

3.4.9 Customer Engagement Tool for Conservation Behaviours

Program Description	This program will provide customers with reports that show them their energy consumption in comparison to their neighbours. The reports will include energy saving tips and offers to reduce their energy bills. Promotional activities will include online tools and paper-based reporting.	
Target Market	Residential	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	Home Energy Reporting SST (40%), Home Energy Reporting (Gas Only) (60%)	
Partners	FortisBC Electric for the Home Energy Reporting SST Measure	
Incremental Cost ($)	$0	Home Energy Reporting SST: $0, Home Energy Reporting (Gas Only): $0
Incentive Amount, FortisBC ($)	$0	Home Energy Reporting SST: $0, Home Energy Reporting (Gas Only): $0
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	Home Energy Reporting SST: $0, Home Energy Reporting (Gas Only): $0
Gas Savings per Participant (GJ/yr)	1.0	Home Energy Reporting SST: 1 GJ, Home Energy Reporting (Gas Only): 1 GJ ***Source:*** OPOWER Evaluation Reports for gas utilities
Elec. Savings per Participant (kWh/yr)	157	Home Energy Reporting SST: 277 kWh, Home Energy Reporting (Gas Only): 0 kWh ***Source:*** OPOWER Evaluation Reports for electric utilities. Savings not accounted for in TRC calculations since they will be claimed by Fortis Electric.
Measure Life (years)	1.0	Home Energy Reporting SST: 1 yrs, Home Energy Reporting (Gas Only): 1 yrs ***Source:*** OPOWER Evaluation Reports for gas utilities
Free Rider Rate (%)	0%	N/A
Spillover Rate (%)	0%	

Customer Engagement Tool (cont'd…)

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	64,125	76,950	89,775	102,600	128,250
	FEVI	7,125	8,550	9,975	11,400	14,250
	FEW	0	0	0	0	0
	Total	71,250	85,500	99,750	114,000	142,500

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$0	$99	$405	$16	$520
	FEVI	$0	$11	$45	$2	$58
	FEW	$0	$0	$0	$0	$0
	Total	$0	$110	$451	$18	$578
	2015					
	FEI	$0	$99	$520	$16	$635
	FEVI	$0	$11	$58	$2	$71
	FEW	$0	$0	$0	$0	$0
	Total	$0	$110	$579	$18	$706
	2016					
	FEI	$0	$99	$648	$16	$763
	FEVI	$0	$11	$72	$2	$85
	FEW	$0	$0	$0	$0	$0
	Total	$0	$110	$721	$18	$848
	2017					
	FEI	$0	$99	$790	$16	$905
	FEVI	$0	$11	$88	$2	$101
	FEW	$0	$0	$0	$0	$0
	Total	$0	$110	$879	$18	$1,006
	2018					
	FEI	$0	$99	$1,046	$16	$1,161
	FEVI	$0	$11	$116	$2	$129
	FEW	$0	$0	$0	$0	$0
	Total	$0	$110	$1,163	$18	$1,290
	Grand Total	**$0**	**$548**	**$3,791**	**$90**	**$4,428**

3.4.10 Financing Pilot

Program Description	This program will facilitate customer access to energy-efficiency financing, both utility-funded on-bill financing and financing through third-party financial institutions. Both on-bill financing and financing through third-party financial institutions will require interest rate buy-downs and incur administration costs. In the case of on-bill financing, most promotion is anticipated to be through contractors. In the case of financial institution partnerships, most promotion will be undertaken by the financial institution. There is much that is unknown, including the measure savings and the Net-to-Gross ratio.	
Target Market	Residential customers of FortisBC in the South Okanagan, from Kelowna to the US border.	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Interest Rate Buy-downs (OBF) (50%), Interest Rate Buy-downs (Financial Institutions) (50%)	
Partners	Interest Rate Buy-downs (OBF): FortisBC Electric, Interest Rate Buy-downs (Financial Institutions): Banks and Credit Unions	
Incremental Cost ($)	$100	Interest Rate Buy-downs (OBF): $100, Interest Rate Buy-downs (Financial Institutions): $100
Incentive Amount, FortisBC ($)	$100	Interest Rate Buy-downs (OBF): $100, Interest Rate Buy-downs (Financial Institutions): $100
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	0.0	
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	N/A	Not applicable
Free Rider Rate (%)	0%	
Spillover Rate (%)	0%	

Financing Pilot (cont'd…)

Participants	**Service Region**	**2014**	**2015**	**2016**	**2017**	**2018**
	FEI	257	590	1,018	1,427	1,760
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	257	590	1,018	1,427	1,760
Expenditures ($000's)	**Service Region**	**Incentives**	**Admin**	**Comm.**	**Evaluation**	**Total**
	2014					
	FEI	$26	$35	$15	$36	$112
	FEVI	$0	$0	$0	$0	$0
	FEW	$0	$0	$0	$0	$0
	Total	$26	$35	$15	$36	$112
	2015					
	FEI	$59	$45	$20	$50	$174
	FEVI	$0	$0	$0	$0	$0
	FEW	$0	$0	$0	$0	$0
	Total	$59	$45	$20	$50	$174
	2016					
	FEI	$102	$63	$20	$50	$235
	FEVI	$0	$0	$0	$0	$0
	FEW	$0	$0	$0	$0	$0
	Total	$102	$63	$20	$50	$235
	2017					
	FEI	$143	$63	$20	$50	$276
	FEVI	$0	$0	$0	$0	$0
	FEW	$0	$0	$0	$0	$0
	Total	$143	$63	$20	$50	$276
	2018					
	FEI	$176	$63	$20	$50	$309
	FEVI	$0	$0	$0	$0	$0
	FEW	$0	$0	$0	$0	$0
	Total	$176	$63	$20	$50	$309
	Grand Total	**$505**	**$269**	**$95**	**$236**	**$1,105**

4 Commercial Energy Efficiency Program Area

4.1 Introduction

For 2014-2018, the suite of Commercial Energy Efficiency Program Area customer offerings has been organized into the following programs:

- Programs that focus on energy-efficient equipment upgrades include:
  - Space Heat program
  - Water Heating program
  - Commercial Food Service program
  - Customized Equipment Upgrade program

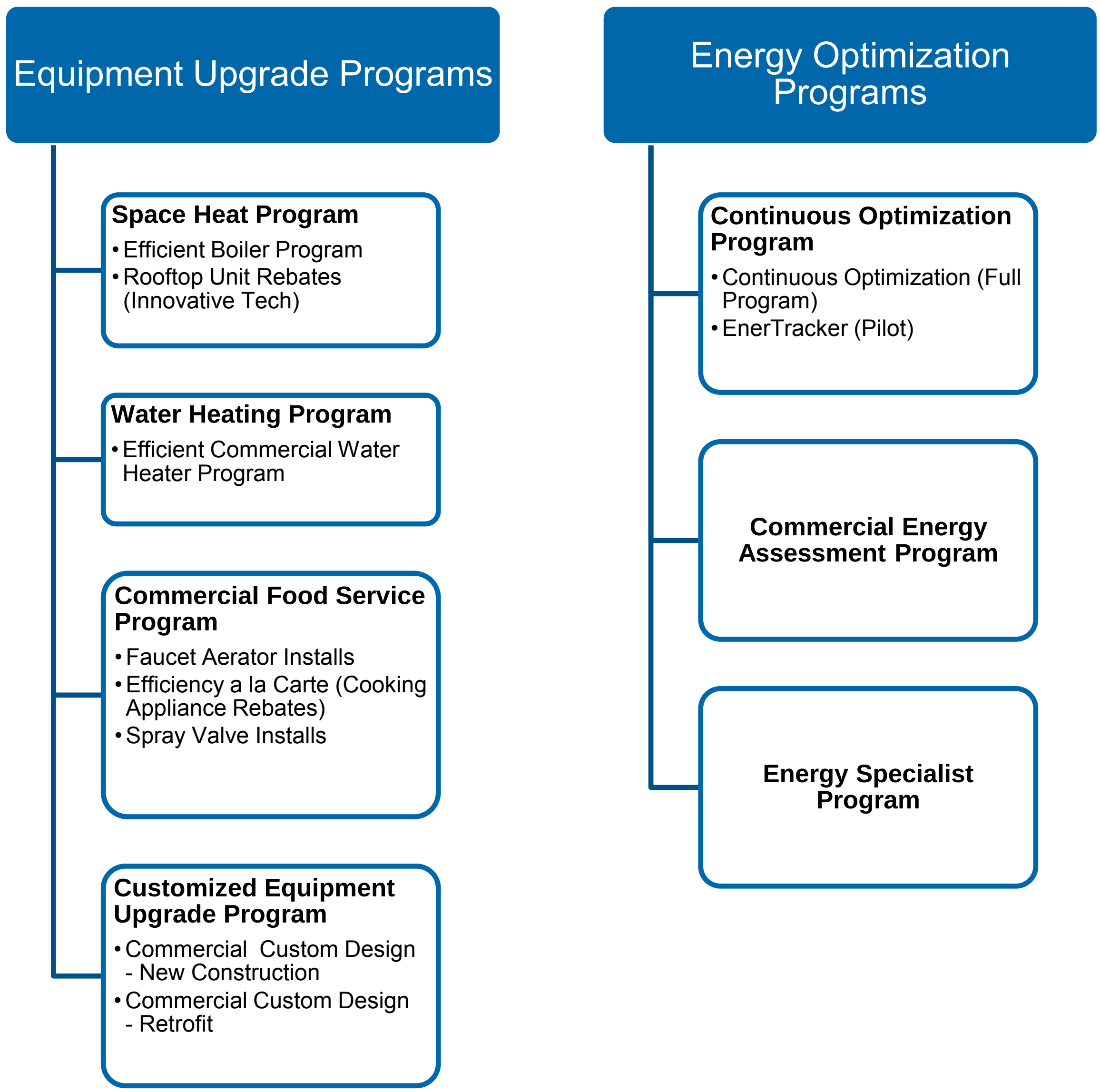
- Programs that focus on energy optimization include:
  - Energy Assessment program
  - EnerTracker program
  - Continuous Optimization program
  - Energy Specialist program

4.2 Commercial Program Consolidation

For the 2014-2018 EEC Plan, the Commercial Energy Efficiency Program Area has placed added emphasis on clustering customer offerings by end use and market segment. As opposed to the previous structure, under which much more measure-specific programs were described, this revised structure supports a streamlining of program communications and delivery strategies. This more streamlined or packaged approach is expected to make it easier for customers to find incentives that are appropriate for their situation.

Exhibit 8 provides a graphic representation of the organization of the Commercial Energy Efficiency Program Area. This Exhibit is provided for this program area given the significant number of measures included for incentives. A visual representation facilitates the understanding of where all these measures reside in the updated program structure. In addition, the Commercial Energy Efficiency Program Area includes a Mechanical Insulation Pilot project, which is described in the Program Profiles section that follows.

Exhibit 8 – Commercial Program Organization



4.3 Selected Highlights

In addition to the program organization revisions noted above, the following changes from the previously-approved 2012-2013 EEC Plan have been incorporated into the 2014-2018 Commercial Energy Efficiency Program Area plan:

- As pre rinse spray valve direct installations are aimed at commercial foodservice establishments, this measure has been integrated into the Commercial sector food service program rather than continuing to be operated as an individual program.

- Development of the process heat program has been assigned to the Industrial sector energy-efficiency program area.

In addition, the following new measures, which were not included in the previous 2012-2013 EEC plan, are included:

- **Rooftop Unit (RTU) Rebates:** This new prescriptive measure, included in the Space Heat program, will encourage the installation of high-efficiency (condensing) rooftop units. The program start date is dependent on completion and successfully verified savings from the Innovative Technologies pilot.

- **EnerTracker:** Enertracker is a subset of the Continuous Optimization (C.Op) program. Providing a lighter level of support, Enertracker attempts to generate cost effective gas savings from customers who are unable or unwilling to participate in the full scale C.Op program. As with the full scale program, Enertracker focuses on building operations and maintenance by providing participants with access to an Energy Management Information System (EMIS). EMIS software provides customers with a detailed picture of their natural gas consumption in "near time". Timely access to this information is expected to speed up fault detection, thereby enabling more rapid corrective action to avoid wasted gas consumption, as well as to assist in the identification of additional potential natural gas conservation measures. Note that this is a pilot program ending December 31, 2015. Should the pilot prove successful, it may be extended past 2015.

- **Low-Flow Faucet Aerators:** This measure, targeted at restaurants and included in the Commercial sector food service program, will see low-flow aerators installed on non-food prep dedicated faucets, such as those found in washrooms and staff areas.

Details on each of these new programs are included in the following program profiles.

4.4 Overview of Results

Exhibit 9 and Exhibit 10 provides a summary of the estimated savings, program expenditures and cost-effectiveness results for each of the programs noted above and for the Commercial Energy Efficiency Program Area as a whole.

Exhibit 9 - Summary of Expenditures for the Commercial Sector Program Portfolio

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Space Heat Program																		
FEI	1,291	1,291	1,540	1,540	1,540	7,203	56	89	66	66	113	389	1,347	1,381	1,606	1,606	1,653	7,592
FEVI	430	430	513	513	513	2,401	9	20	9	9	25	72	439	450	523	523	538	2,473
Total	1,722	1,722	2,053	2,053	2,053	9,604	64	109	75	75	138	462	1,786	1,831	2,128	2,128	2,191	10,066
Water Heating Program																		
FEI	172	189	210	232	236	1,040	34	52	34	34	52	205	206	241	244	265	288	1,245
FEVI	28	31	34	38	38	169	4	7	5	4	7	28	33	38	39	42	46	198
Total	201	220	245	269	275	1,209	38	59	38	38	59	233	239	279	283	307	334	1,442
Commercial Food Service Program																		
FEI	243	265	287	353	441	1,588	126	123	139	96	130	613	368	388	425	449	571	2,201
FEVI	27	29	32	39	49	176	14	14	16	11	15	71	41	44	48	50	64	247
Total	270	294	319	392	490	1,765	140	137	155	108	145	684	410	431	473	500	635	2,448
Customized Equipment Upgrade Program																		
FEI	1,682	2,102	1,892	1,892	1,892	9,459	196	200	194	243	194	1,027	1,878	2,302	2,086	2,135	2,086	10,486
FEVI	297	371	334	334	334	1,669	22	22	21	30	21	116	318	393	355	364	355	1,786
Total	1,978	2,473	2,226	2,226	2,226	11,129	217	222	215	272	215	1,143	2,196	2,696	2,441	2,498	2,441	12,272
EnerTracker Program																		
FEI	296	394	0	0	0	690	113	148	13	0	0	274	409	543	13	0	0	964
* Continuous Optimization Program																		
FEI	2,480	1,904	1,491	1,167	927	7,969	175	181	154	156	154	819	2,655	2,085	1,645	1,322	1,081	8,789
FEVI	103	79	62	49	39	332	20	21	18	18	18	94	124	100	80	66	56	426
Total	2,584	1,983	1,553	1,215	966	8,301	195	202	171	173	171	913	2,779	2,185	1,724	1,389	1,137	9,214
Commercial Energy Assessment Program																		
FEI	341	341	341	341	341	1,704	73	79	98	73	79	401	414	419	438	414	419	2,105
FEVI	38	38	38	38	38	189	8	9	11	8	9	45	46	47	49	46	47	234
Total	379	379	379	379	379	1,894	81	87	108	81	87	446	460	466	487	460	466	2,339

* Program requires the MTRC in order to pass the economic screen

Summary of Expenditures for the Commercial Sector Program Portfolio (cont'd…)

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Energy Specialist Program																		
FEI	1,296	1,512	1,728	1,512	1,296	7,344	101	115	130	115	101	562	1,397	1,627	1,858	1,627	1,397	7,906
FEVI	324	378	432	378	324	1,836	25	29	32	29	25	140	349	407	464	407	349	1,976
Total	1,620	1,890	2,160	1,890	1,620	9,180	126	144	162	144	126	702	1,746	2,034	2,322	2,034	1,746	9,882
Mechanical Insulation Pilot																		
FEI	0	0	0	0	0	0	8	8	0	0	0	16	8	8	0	0	0	16
Non-Program Specific Expenses																		
FEI	0	0	0	0	0	0	935	935	935	935	935	4,675	935	935	935	935	935	4,675
FEVI	0	0	0	0	0	0	165	165	165	165	165	825	165	165	165	165	165	825
Total	0	0	0	0	0	0	1,100	1,100	1,100	1,100	1,100	5,500	1,100	1,100	1,100	1,100	1,100	5,500
ALL PROGRAMS																		
FEI	7,801	7,998	7,488	7,036	6,674	36,997	1,816	1,931	1,761	1,717	1,757	8,982	9,617	9,929	9,250	8,753	8,431	45,979
FEVI	1,247	1,357	1,445	1,389	1,335	6,773	268	287	277	274	285	1,391	1,515	1,644	1,722	1,663	1,620	8,165
Total	**9,049**	**9,355**	**8,934**	**8,424**	**8,009**	**43,771**	**2,083**	**2,218**	**2,038**	**1,992**	**2,042**	**10,373**	**11,132**	**11,573**	**10,972**	**10,416**	**10,051**	**54,144**

* Program requires the MTRC in order to pass the economic screen

Exhibit 10 - Summary of Savings and Cost-Effectiveness Results for the Commercial Sector Program Portfolio

Program and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios				
	2014	2015	2016	2017	2018		TRC	MTRC	Utility	Participant	RIM
Space Heat Program											
FEI	39,810	79,621	125,989	172,357	218,726	2,194,317	2.48	N/A	2.99	3.69	0.70
FEVI	13,270	26,540	41,996	57,452	72,909	750,616	2.58	N/A	3.13	6.29	0.42
Total	53,081	106,161	167,985	229,810	291,634	2,944,933	2.50	N/A	3.03	4.34	0.63
Water Heating Program											
FEI	10,856	22,752	35,987	50,560	65,431	488,175	1.13	N/A	3.86	1.61	0.73
FEVI	1,767	3,704	5,858	8,231	10,652	80,974	1.16	N/A	4.01	2.79	0.43
Total	12,623	26,456	41,845	58,791	76,083	569,149	1.14	N/A	3.88	1.78	0.69
Commercial Food Service Program											
FEI	11,015	23,031	36,048	52,069	72,096	528,918	1.78	N/A	2.38	3.15	0.66
FEVI	1,224	2,559	4,005	5,785	8,011	59,911	1.79	N/A	2.39	5.39	0.40
Total	12,238	25,589	40,053	57,855	80,106	588,829	1.78	N/A	2.38	3.37	0.63
Customized Equipment Upgrade Program											
FEI	39,151	88,089	132,134	176,179	220,224	2,299,150	1.06	N/A	2.28	1.69	0.65
FEVI	6,909	15,545	23,318	31,090	38,863	416,933	1.10	N/A	2.42	2.81	0.41
Total	46,060	103,635	155,452	207,269	259,087	2,716,083	1.07	N/A	2.30	1.86	0.62
EnerTracker Program											
FEI	93,462	124,616	0	0	0	210,127	1.57	N/A	1.51	3.88	0.51
* Continuous Optimization Program											
FEI	98,954	228,355	394,801	479,546	507,456	2,011,270	0.82	2.37	1.97	1.38	0.60
FEVI	4,123	9,515	16,450	19,981	21,144	84,599	0.77	2.23	1.71	2.23	0.37
Total	103,077	237,870	411,251	499,527	528,600	2,095,870	0.82	2.36	1.96	1.42	0.59
Commercial Energy Assessment Program											
FEI	41,628	41,628	41,628	41,628	41,628	183,222	1.00	N/A	0.72	2.64	0.38
FEVI	4,625	4,625	4,625	4,625	4,625	20,464	1.00	N/A	0.71	4.03	0.28
Total	46,253	46,253	46,253	46,253	46,253	203,686	1.00	N/A	0.72	2.78	0.37
Energy Specialist Program											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	1.00	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	1.00	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	1.00	0.00
Mechanical Insulation Pilot											
FEI	1,000	2,000	3,000	4,000	5,000	50,531	5.60	N/A	29.45	8.03	0.89
Non-Program Specific Expenses											
FEI	No Direct Savings						No Direct Savings				
FEVI											
Total											
ALL PROGRAMS											
FEI	335,875	610,092	769,587	976,340	1,130,560	7,965,710	1.03	N/A	1.68	1.93	0.59
FEVI	31,919	62,488	96,253	127,165	156,203	1,413,496	1.21	N/A	1.75	3.63	0.38
Total	**367,794**	**672,580**	**865,840**	**1,103,505**	**1,286,763**	**9,379,206**	**1.05**	N/A	**1.69**	**2.18**	**0.56**

* Program requires the MTRC in order to pass the economic screen

4.5 Program Profiles

The following pages provide profiles for each of the programs shown above in Exhibit 9 and Exhibit 10.

4.5.1 Space Heat Program

Program Description	This program will provide rebates for the installation of high-efficiency space heating equipment in Commercial sector applications. This includes rebates for high-efficiency boilers currently delivered to the market via the Efficient Boiler program. Based on the results of the Condensing Gas-Fired Ventilation Unit pilot program undertaken by Innovative Technologies, rebates for condensing rooftop units are expected to be introduced to the program in 2016 or 2017. Note that condensing rooftop unit assumptions may change based on the actual results of the pilot program. Promotional activities will include print and online communications, tradeshows, and leveraging FortisBC Energy Solution Managers and Energy Specialists to increase program uptake with Commercial sector customers while also garnering program support through industry associations.	
Target Market	Commercial customers	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	Condensing boiler (75%), Near condensing boiler (3%), Condensing Rooftop Unit (22%)	
Partners	N/A	
Incremental Cost ($)	$15,818	Condensing boiler: $17,793, Near condensing boiler: $20,683, Condensing Rooftop Unit: $4,000 ***Sources:*** Based on Efficient Boiler Program paid participant results weighted over the past 3 years, Navigant Consulting (16 April 2009), Measures and Assumptions for Demand Side Management Planning Appendix C: Substantiation Sheets Ontario Energy Board, pp. 134-207, Prism Engineering Pre-feasibility Study for Condensing Rooftop Units January 2012
Incentive Amount, FortisBC ($)	$10,700	Condensing boiler: $12,262, Near condensing boiler: $6,964, Condensing Rooftop Unit: $3,000 ***Sources:*** Based on Efficient Boiler Program paid participants in 2012, Prism Engineering Pre-feasibility Study for Condensing Rooftop Units January 2012
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	394.7	Condensing boiler: 438.0 GJ, Near condensing boiler: 836.0 GJ, Condensing Rooftop Unit: 62.8 GJ ***Sources:*** Based on paid program participants in 2012, Prism Engineering Pre-feasibility Study: Condensing Rooftop Units January 2012
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	19.7	Condensing boiler: 20 yrs, Near condensing boiler: 20 yrs, Condensing Rooftop Unit: 18 yrs ***Sources:*** Efficient Boiler Program impact evaluation study June 12, 2003, Prism Engineering Pre-feasibility Study: Condensing Rooftop Units January 2012
Free Rider Rate (%)	16%	Condensing boiler: 18%, Near condensing boiler: 18%, Condensing Rooftop Unit: 5% ***Sources:*** Efficient Boiler Program impact evaluation study June 12, 2003, Engineered Air shipping data (2011-2012 British Columbia)
Spillover Rate (%)	0%	

Space Heat Program (cont'd…)

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	106	106	151	151	151
	FEVI	36	36	51	51	51
	FEW	1	1	2	2	2
	Total	143	143	204	204	204

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
				2014		
	FEI	$1,274	$16	$28	$11	$1,329
	FEVI	$430	$2	$3	$4	$439
	FEW	$17	$0	$0	$0	$18
	Total	$1,722	$18	$32	$15	$1,786
				2015		
	FEI	$1,274	$16	$28	$44	$1,363
	FEVI	$430	$2	$3	$15	$450
	FEW	$17	$0	$0	$1	$18
	Total	$1,722	$18	$32	$60	$1,831
				2016		
	FEI	$1,520	$16	$40	$9	$1,584
	FEVI	$513	$2	$5	$3	$523
	FEW	$21	$0	$0	$0	$21
	Total	$2,053	$18	$45	$12	$2,128
				2017		
	FEI	$1,520	$16	$40	$9	$1,584
	FEVI	$513	$2	$5	$3	$523
	FEW	$21	$0	$0	$0	$21
	Total	$2,053	$18	$45	$12	$2,128
				2018		
	FEI	$1,520	$16	$40	$56	$1,631
	FEVI	$513	$2	$5	$19	$538
	FEW	$21	$0	$0	$1	$22
	Total	$2,053	$18	$45	$75	$2,191
	Grand Total	**$9,604**	**$90**	**$198**	**$174**	**$10,066**

4.5.2 Water Heating Program

Program Description	This program provides rebates for the installation of high-efficiency commercial water heaters with thermal efficiencies greater than or equal to 84%. Promotional activities will include print and online communications, tradeshows, and leveraging FortisBC Energy Solution Managers and Energy Specialists to increase program uptake with Commercial sector customers while also garnering program support through industry associations.	
Target Market	Commercial customers	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	Condensing storage and volume type water heater (50%), Near condensing storage and volume type water heater (3%), Condensing on-demand water heater (47%)	
Partners	N/A	
Incremental Cost ($)	$7,782	Condensing storage and volume type water heater: $8,832, Near condensing storage and volume type water heater: $19,529, Condensing on-demand water heater: $5,915 ***Source:*** Based on actual program participant results weighted over three years
Incentive Amount, FortisBC ($)	$1,908	Condensing storage and volume type water heater: $2,623, Near condensing storage and volume type water heater: $2,559, Condensing on-demand water heater: $1,106 ***Source:*** Based on actual program participant results 2012
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	126.4	Condensing storage and volume type water heater: 159 GJ, Near condensing storage and volume type water heater: 75 GJ, Condensing on-demand water heater: 95 GJ ***Source:*** Based on actual program participant results 2012
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	12.0	Condensing storage and volume type water heater: 12 yrs, Near condensing storage and volume type water heater: 12 yrs, Condensing on-demand water heater: 12 yrs ***Sources:*** 2010 Conservation Potential Review, Navigant Consulting (16 April 2009) Measures and Assumptions for Demand Side Management Planning Appendix C: Substantiation Sheets Ontario Energy Board pp. 210-226
Free Rider Rate (%)	5%	Condensing storage and volume type water heater: 5%, Near condensing storage and volume type water heater: 5%, Condensing on-demand water heater: 5% ***Source:*** Navigant Consulting (16 April 2009), Measures and Assumptions for Demand Side Management Planning, Appendix C: Substantiation Sheets, Ontario Energy Board, pp. 210-226
Spillover Rate (%)	0%	

Water Heating Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	89	98	109	120	122
FEVI	15	16	18	20	20
FEW	1	1	1	1	1
Total	105	115	128	141	144

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$170	$1	$20	$13	$204
FEVI	$28	$0	$2	$2	$33
FEW	$2	$0	$0	$0	$2
Total	$201	$1	$22	$15	$239
2015					
FEI	$187	$1	$20	$31	$238
FEVI	$31	$0	$2	$5	$38
FEW	$2	$0	$0	$0	$3
Total	$220	$1	$22	$36	$279
2016					
FEI	$208	$1	$20	$13	$242
FEVI	$34	$0	$2	$2	$39
FEW	$2	$0	$0	$0	$3
Total	$245	$1	$22	$15	$283
2017					
FEI	$229	$1	$20	$13	$262
FEVI	$38	$0	$2	$2	$42
FEW	$3	$0	$0	$0	$3
Total	$269	$1	$22	$15	$307
2018					
FEI	$234	$1	$20	$31	$285
FEVI	$38	$0	$2	$5	$46
FEW	$3	$0	$0	$0	$3
Total	$275	$1	$22	$36	$334
Grand Total	**$1,209**	**$5**	**$111**	**$117**	**$1,442**

4.5.3 Commercial Food Service Program

Program Description	This program, launched in September 2012, offers a suite of rebates for the installation of high-efficiency commercial cooking appliances. Promotional activities will include print and online communications, tradeshows, and leveraging FortisBC Energy Solution Managers and Energy Specialists to increase program uptake with Commercial sector customers while also garnering program support through industry associations.	
Target Market	Commercial customers	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	Deep fryer (16%), Griddle (4%), Combination oven (10%), Convection oven (10%), Rack oven (3%), Conveyor oven (6%), Steam cooker (3%), Dishwasher (5%), Spray Valves (15%), Faucet Aerators (29%)	
Partners	N/A	
Incremental Cost ($)	$1,451	Deep fryer: $1,420, Griddle: $860, Combination oven: $4,948, Convection oven: $1,890, Rack oven: $5,060, Conveyor oven: $3,240, Steam cooker: $1,000, Dishwasher: $2,513, Spray valve: $130, Faucet aerator: $16 ***Source:*** Foodservice Incentive Program Study 2012, Fisher-Nickel Inc. (Appendix A), past spray valve program data, 2013 direct install faucet aerator program development findings, Commercial Dishwashers Program Guide (2009) CEE.
Incentive Amount, FortisBC ($)	$801	Deep fryer: $1,100, Griddle: $500, Combination oven: $2,500, Convection oven: $1,000, Rack oven: $3,000, Conveyor oven: $1,850, Steam cooker: $200, Dishwasher: $663, Spray valve: $130, Faucet aerator: $16 ***Source:*** Foodservice Incentive Program Study 2012, Fisher-Nickel Inc. (Appendix A)), past spray valve program data, 2013 direct install faucet aerator program development findings.
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	45.0	Deep fryer: 57 GJ, Griddle: 16 GJ, Combination oven: 120 GJ, Convection oven: 34 GJ, Rack oven: 166 GJ, Conveyor oven: 86 GJ, Steam cooker: 220 GJ, Dishwasher: 52 GJ, Spray valve: 9 GJ, Faucet aerator: 1.2 GJ ***Sources:*** Foodservice Incentive Program Study 2012, Fisher-Nickel Inc. (Appendix A), , past spray valve program data, Marbek Conservation Potential Review (2010), Commercial Dishwashers Program Guide (2009) CEE.
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	9.1	Deep fryer: 12 yrs, Griddle: 12 yrs, Combination oven: 12 yrs, Convection oven: 12 yrs, Rack oven: 12 yrs, Conveyor oven: 12 yrs, Steam cooker: 12 yrs, Dishwasher: 16 yrs, Spray valve: 5 yrs, Faucet aerator: 5 yrs ***Sources:*** Foodservice Incentive Program Study 2012, Fisher-Nickel Inc. Marbek Conservation Potential Review (2010), Commercial Dishwashers Program Guide (2009) CEE.
Free Rider Rate (%)	16%	Deep fryer: 20%, Griddle: 20%, Combination oven: 20%, Convection oven: 20%, Rack oven: 20%, Conveyor oven: 20%, Steam cooker: 20%, Dishwasher: 10%, Spray valve: 12%, Faucet aerator: 12% ***Source:*** Foodservice Incentive Program Study 2012, Fisher-Nickel Inc. (Appendix A), past spray valve program data.
Spillover Rate (%)	0%	

Commercial Food Service Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	300	327	354	436	545
FEVI	34	37	40	49	61
FEW	3	4	4	5	6
Total	337	367	398	490	612

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$240	$4	$107	$13	$364
FEVI	$27	$1	$12	$2	$41
FEW	$3	$0	$1	$0	$4
Total	$270	$5	$121	$15	$410
2015					
FEI	$262	$4	$107	$11	$383
FEVI	$29	$1	$12	$1	$44
FEW	$3	$0	$1	$0	$4
Total	$294	$5	$121	$12	$431
2016					
FEI	$284	$4	$80	$53	$421
FEVI	$32	$1	$9	$6	$48
FEW	$3	$0	$1	$1	$5
Total	$319	$5	$90	$60	$473
2017					
FEI	$349	$4	$80	$12	$444
FEVI	$39	$1	$9	$1	$50
FEW	$4	$0	$1	$0	$5
Total	$392	$5	$90	$13	$500
2018					
FEI	$436	$4	$80	$45	$564
FEVI	$49	$1	$9	$5	$64
FEW	$5	$0	$1	$1	$6
Total	$490	$5	$90	$50	$635
Grand Total	**$1,765**	**$23**	**$511**	**$150**	**$2,448**

4.5.4 Customized Equipment Upgrade Program

Program Description	This program provides eligible customers with funding towards the completion of a detailed energy study, aimed at identifying customized energy saving opportunities within their facilities, and subsequent capital incentive funding to encourage the implementation of any cost-effective measures identified in the study. The program will capture energy savings associated with measures that are otherwise difficult to incent as part of a prescriptive program because they are complex, and one project may include multiple measures with interactive effects. Interactive effects are situations where changes made to one energy-using system may have a direct influence on the energy consumption of another system. For example, reduced lighting power may lead to an increased requirement for space heating. The required energy study must account for these effects where applicable. The expected energy savings, measures, capital cost, incentives etc., will necessarily vary depending on the customer. Each project will be submitted to a TRC test and must be approved by the utility.	
Target Market	Medium to large Commercial/Institutional customers	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	New Construction Energy Study (15%), New Construction Capital Incentive (12%), Retrofit Energy Study (41%), Retrofit Capital Incentive (31%)	
Partners	BC Hydro (Power Smart)	
Incremental Cost ($)	$71,959	New Construction Energy Study: $21,565, New Construction Capital Incentive: $130,000, Retrofit Energy Study: $15,000, Retrofit Capital Incentive: $150,000 ***Sources:*** Estimates based on data from current New Construction program participants, Retrofit Beta test program participants, PSECA Initiative participants, and estimate of worst case measure cost allowable under the program rules
Incentive Amount, FortisBC ($)	$28,426	New Construction Energy Study: $21,565, New Construction Capital Incentive: $24,165, Retrofit Energy Study: $15,000 , Retrofit Capital Incentive: $51,490 ***Sources:*** Estimates based on data from current New Construction program participants, Retrofit Beta test program participants, and PSECA Initiative participants
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	735.3	New Construction Energy Study: 0 GJ, New Construction Capital Incentive: 1,373 GJ, Retrofit Energy Study: 0 GJ, Retrofit Capital Incentive: 1,830 GJ
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	10.5	New Construction Energy Study: N/A, New Construction Capital Incentive: 30 yrs, Retrofit Energy Study: N/A, Retrofit Capital Incentive: 20 yrs ***Source:*** Estimated values, based on the expected life of a new building, and typical measure lives of gas burning equipment
Free Rider Rate (%)	10%	New Construction Energy Study: 10%, New Construction Capital Incentive: 10%, Retrofit Energy Study: 10%, Retrofit Capital Incentive: 10%
Spillover Rate (%)	0%	

Customized Equipment Upgrade Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	58	72	65	65	65
FEVI	10	13	12	12	12
FEW	1	2	2	2	2
Total	70	87	78	78	78

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$1,642	$140	$41	$12	$1,836
FEVI	$297	$16	$4	$2	$318
FEW	$40	$1	$0	$0	$42
Total	$1,978	$158	$45	$15	$2,196
2015					
FEI	$2,053	$140	$41	$17	$2,251
FEVI	$371	$16	$4	$3	$393
FEW	$49	$1	$0	$0	$52
Total	$2,473	$158	$45	$20	$2,696
2016					
FEI	$1,847	$140	$41	$11	$2,039
FEVI	$334	$16	$4	$2	$355
FEW	$45	$1	$0	$0	$47
Total	$2,226	$158	$45	$13	$2,441
2017					
FEI	$1,847	$140	$41	$58	$2,087
FEVI	$334	$16	$4	$11	$364
FEW	$45	$1	$0	$1	$48
Total	$2,226	$158	$45	$70	$2,498
2018					
FEI	$1,847	$140	$41	$11	$2,039
FEVI	$334	$16	$4	$2	$355
FEW	$45	$1	$0	$0	$47
Total	$2,226	$158	$45	$13	$2,441
Grand Total	**$11,129**	**$788**	**$225**	**$131**	**$12,272**

Notes:

1. Every attempt has been made to provide an accurate representation of the Commercial custom design program but certain limitations must be acknowledged and understood. This program, being more complex and non-prescriptive in nature, has variable measure savings, costs, incentives and/or cash flows. The numbers presented here are based on values observed for the first 5 participants in the Beta test stage of the Commercial custom design program, projects from the PSECA Initiative, as well as a conservative estimate of measure costs. While these values represent the best available information to date, they may not be representative of program results over the longer term as these are strongly driven by the specific projects participating in the program at any given time. However, it should be understood that under the program rules no incentives will be provided for measures having a TRC less than 1.0. Thus, the Companies are confident that the program will be cost effective.

4.5.5 EnerTracker Program

Program Description	This 3-year pilot program is a subset of the continuous optimization (C.Op) program. It provides participants who are otherwise unable or unwilling to participate in the full C.Op program with access to an Energy Management Information System (EMIS). EMIS software provides customers with a detailed picture of their natural gas consumption in "near time". Timely access to this information is expected to speed up fault detection, thereby enabling more rapid corrective action to avoid wasted gas consumption, as well as to assist in the identification of additional potential natural gas conservation measures. Note that this pilot program slated to end December 31, 2015. If the program proves successful, it may be extended past 2015.	
Target Market	Commercial customers with existing AMR devices (FEI only).	
New vs. Retrofit	Retrofit	
Eligible Measures	Energy Management Information System	
Partners	N/A	
Incremental Cost ($)	$730	Actual cost of annual EMIS license and data fees. These fees are paid for by the utility for the duration of a participant's involvement in the pilot.. For example, if a customer is in the program for 3 years, the utility will pay the incentive amount each year for 3 years.
Incentive Amount, FortisBC ($)	$730	See Incremental Cost
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	245.5	Approximately 2% of annual natural gas consumption, assuming average annual participant consumption of 12,275 GJ ***Source:*** Proof of concept conducted by Pulse Energy.
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	1.0	Measure life is one year due to the nature of the pilot program being based around an annual software subscription fee
Free Rider Rate (%)	6%	Proof of concept conducted by Pulse Energy shows that approximately 6.4% of medium to large commercial buildings in BC have adopted EMIS (since January 2009) without utility incentives or grant funding.
Spillover Rate (%)	0%	

EnerTracker Program (cont'd…)

Participants[1]

Service Region	2014	2015	2016	2017	2018
FEI	405	540	0	0	0
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	405	540	0	0	0

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$296	$99	$1	$13	$409
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$296	$99	$1	$13	$409
2015					
FEI	$394	$121	$1	$26	$543
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$394	$121	$1	$26	$543
2016					
FEI	$0	$0	$0	$13	$13
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$0	$0	$13	$13
2017					
FEI	$0	$0	$0	$0	$0
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0
2018					
FEI	$0	$0	$0	$0	$0
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0
Grand Total	**$690**	**$220**	**$2**	**$52**	**$951**

Notes:
1. Participant count for this program is cumulative

4.5.6 Continuous Optimization Program

Program Description	Hidden building operational problems can result in inefficiencies and increased natural gas consumption. The Continuous Optimization Program (C.Op.), in partnership with BC Hydro's Power Smart, is designed to help Commercial sector building owners identify and correct energy wasting operational faults and continuously monitor building performance to help maintain and improve energy efficiency, resulting in reduced operating costs. Eligible customers will receive funding towards the cost of recommissioning services to study their building and recommend energy-efficiency improvements, as well as access to an EMIS to assist in tracking their building's performance after the recommissioning work is complete. In return, participants must agree to implement, at their own cost, measures identified by the recommissioning study that, when combined, will have a payback of two years or less.	
Target Market	Commercial customers with buildings >50,000 ft^2 who consume an average of 7,500 GJ of natural gas/year or natural gas is 40% of their building's total energy consumption	
New vs. Retrofit	Retrofit	
Eligible Measures	Building recommissioning and EMIS	
Partners	BC Hydro	
Incremental Cost ($)	$41,485	Includes all costs covered by the incentive (described below) as well as the customers' cost of implementing energy conserving measures as identified in the recommissioning report, and customer labour to interact with the EMIS. Incremental cost is nominal. ***Source:*** BC Hydro supplied data.
Incentive Amount, FortisBC ($)	$18,913	Based on natural gas portion of recommissioning study, meter upgrade costs, and EMIS costs over 5 years. Incentive amount is nominal. ***Source:*** BC Hydro supplied data.
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	1,074.0	***Source:*** BC Hydro supplied data based on actual program participants.
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	5.0	Based on the duration of utility support for the energy management information system, plus one year.
Free Rider Rate (%)	0%	***Source:*** BC Hydro. Some Commercial sector customers implement an EMIS without utility support. Other customers perform recommissioning work without utility support. However, to the utility's knowledge customers do not, to any significant degree, simultaneously implement both an EMIS and perform recommissioning work without utility support.
Spillover Rate (%)	0%	

Continuous Optimization Program (cont'd…)

Participants[1]

Service Region	2014	2015	2016	2017	2018
FEI	111	257	443	539	570
FEVI	5	11	19	23	24
FEW	1	3	5	6	6
Total	117	270	467	567	600

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$2,456	$142	$21	$12	$2,630
FEVI	$103	$16	$3	$1	$124
FEW	$25	$0	$0	$0	$25
Total	$2,584	$158	$24	$13	$2,779
2015					
FEI	$1,885	$142	$21	$18	$2,066
FEVI	$79	$16	$3	$2	$100
FEW	$19	$0	$0	$0	$19
Total	$1,983	$158	$24	$20	$2,185
2016					
FEI	$1,476	$142	$0	$12	$1,629
FEVI	$62	$16	$0	$1	$80
FEW	$15	$0	$0	$0	$15
Total	$1,553	$158	$0	$13	$1,724
2017					
FEI	$1,155	$142	$0	$13	$1,311
FEVI	$49	$16	$0	$2	$66
FEW	$12	$0	$0	$0	$12
Total	$1,215	$158	$0	$15	$1,389
2018					
FEI	$918	$142	$0	$12	$1,072
FEVI	$39	$16	$0	$1	$56
FEW	$9	$0	$0	$0	$9
Total	$966	$158	$0	$13	$1,137
Grand Total	**$8,301**	**$792**	**$47**	**$74**	**$9,214**

Notes:
1. Participant count for this program is cumulative
2. TRC calculations are based on NPV of cash flows from 2014-2018
3. Every attempt has been made to provide an accurate representation of this program but certain limitations must be acknowledged and understood. This program, being more complex and non-prescriptive in nature, has variable measure savings, costs, incentives and/or cash flows. Participation in the program lasts for 7 years, including approximately 12 months of baseline data collection, 24 months of recommissioning work and 48 months of monitoring and continuous improvement. Participants are recorded as soon as they are accepted into the program; however, natural gas savings and incentive expenses occur at various times throughout the 7 year period.

4.5.7 Commercial Energy Assessment Program

Program Description	This program identifies inefficiencies at the participant's facilities via an on-site walkthrough assessment by an energy-efficiency consultant. The consultant then produces a report that describes the observed inefficiencies, outlines proposed solutions, and identifies any applicable incentive programs. FortisBC then forwards the report to the participant. The program for 2014-2018 reflects revisions made in 2013 to: ● Provide dual-fuel energy assessments in the shared service territory ● Increase FortisBC brand permeation and emphasis on FortisBC Commercial sector programs in energy assessment reports ● Install an element of accountability to encourage a greater implementation of energy saving measures post-assessment ● Diversify service providers and ensure fair market value ● Re-evaluate program target audience(s) and ensure program offering is aligned with their needs	
Target Market	Commercial customers	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Medium business walkthrough energy assessment and written report (25%), Small business walkthrough energy assessment and written report (51%), Agriculture walkthrough energy assessment and written report (3%), Restaurant walkthrough energy assessment and written report (21%)	
Partners	N/A	
Incremental Cost ($)	$723	Medium business walkthrough energy assessment and written report: $1,583 - Incentive amount is the average cost of conducting an on-site energy assessment and follow-up report in the FEI service territory, Small business walkthrough energy assessment and written report: $350 (Note 1 below), Agriculture walkthrough energy assessment and written report: $2,500 (Note 2 below), Restaurant walkthrough energy assessment and written report: $350 (Note 1 below)
Incentive Amount, FortisBC ($)	$723	Medium business walkthrough energy assessment and written report: $1,583 - Incentive amount is the average cost of conducting an on-site energy assessment and follow-up report in the FEI service territory, Small business walkthrough energy assessment and written report: $350 (Note 1 below), Agriculture walkthrough energy assessment and written report: $2,500 (Note 2 below), Restaurant walkthrough energy assessment and written report: $350 (Note 1 below)
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	135.8	Medium business walkthrough energy assessment and written report: 488 GJ ***Source:*** Average derived from Friuch 2010 Energy Assessment Evaluation Small business walkthrough energy assessment and written report: 15 GJ (Note 1 below), Agriculture walkthrough energy assessment and written report: 100 GJ (Note 2 below) Restaurant walkthrough energy assessment and written report: 15 GJ (Note 2 below)
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	1.0	Medium business walkthrough energy assessment and written report: 1 yr, Small business walkthrough energy assessment and written report: 1 yr, Agriculture walkthrough energy assessment and written report: 1 yr, Restaurant walkthrough energy assessment and written report: 1 yr ***Source:*** Conservative estimates based on the implementation primarily of low-cost, simple recommendations (such as operational adjustments) from energy assessment report.
Free Rider Rate (%)	35%	Medium business walkthrough energy assessment and written report: 35%, Small business walkthrough energy assessment and written report: 35%, Agriculture walkthrough energy assessment and written report: 35%, Restaurant walkthrough energy assessment and written report: 35% ***Source:*** Derived from Friuch 2010 Energy Assessment Evaluation.
Spillover Rate (%)	0%	

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	466	466	466	466	466
	FEVI	52	52	52	52	52
	FEW	5	5	5	5	5
	Total	524	524	524	524	524

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$337	$57	$4	$12	$409
	FEVI	$38	$6	$0	$1	$46
	FEW	$4	$1	$0	$0	$5
	Total	$379	$64	$4	$13	$460
	2015					
	FEI	$337	$62	$4	$12	$415
	FEVI	$38	$7	$0	$1	$47
	FEW	$4	$1	$0	$0	$5
	Total	$379	$70	$5	$13	$466
	2016					
	FEI	$337	$57	$4	$36	$434
	FEVI	$38	$6	$0	$4	$49
	FEW	$4	$1	$0	$0	$5
	Total	$379	$64	$4	$40	$487
	2017					
	FEI	$337	$57	$4	$12	$409
	FEVI	$38	$6	$0	$1	$46
	FEW	$4	$1	$0	$0	$5
	Total	$379	$64	$4	$13	$460
	2018					
	FEI	$337	$62	$4	$12	$415
	FEVI	$38	$7	$0	$1	$47
	FEW	$4	$1	$0	$0	$5
	Total	$379	$70	$5	$13	$466
	Grand Total	**$1,894**	**$332**	**$22**	**$92**	**$2,339**

Notes:
1. Small business/Restaurant assessment incremental cost/incentive amount is based on a qualified individual conducting an on-site energy assessment and producing a report ($50/hr for 5 hours + $50 in expenses) based on findings. 15% contingency included. Savings based on conservative 5% of average annual Small business/Restaurant consumption (300 GJ).
2. Agriculture assessment incremental cost/incentive amount is based on a specialized P.Eng conducting a 1-1/2-day on-site energy assessment ($100/hr for 12 hours + $100 in expenses) and producing a detailed report (8 hours) based on findings. 20% contingency included. Savings based on 1% of average annual agricultural customer consumption (10,000 GJ). Average annual consumption is derived from total consumption of FortisBC agricultural customers (6m GJ) divided by the estimated total number of agricultural customers (600).

4.5.8 Energy Specialist Program

Program Description	This program will fund energy specialist positions, whose key priority is to identify opportunities for their organization to participate in FortisBC's EEC programs. The energy specialist reports to and supports the BC Hydro-funded energy manager on holistic energy reduction projects, while also focusing on identifying opportunities to use natural gas more efficiently. Energy specialist positions are funded by FortisBC up to $60,000 for a period of one year. This program is funded as an enabling program but claims natural gas savings for those projects completed by energy specialists that are not claimed by another EEC program and are verified by a third-party engineering firm through the annual Energy Specialist Program evaluation study. No promotional activities are planned for this program other than a presence on the FortisBC web site. New participation will be solicited through direct communications utilizing existing FortisBC and BC Hydro account management channels.	
Target Market	Large Commercial and Institutional Customers	
New vs. Retrofit	Primarily retrofit	
Eligible Measures	Energy Specialist	
Partners	BC Hydro (Energy Manager Program). Energy Specialists are typically placed in an organization with a BC Hydro funded Energy Manager. The Energy Specialist works with their respective Energy Manager as an energy management team.	
Incremental Cost ($)	$60,000	
Incentive Amount, FortisBC ($)	$60,000	
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	0[5]	
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	N/A	Not applicable
Free Rider Rate (%)	0%	Learnings from 2010/2011 Energy Specialist Pilot Program
Spillover Rate (%)	0%	

[5] Although energy savings will be reported from this program as indicated in the program description, these energy savings come from unique ad hoc projects undertaken by energy specialists and therefore cannot be forecast.

Energy Specialist Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	22	25	29	25	22
FEVI	5	6	7	6	5
FEW	0	0	0	0	0
Total	27	32	36	32	27

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$1,296	$14	$0	$86	$1,397
FEVI	$324	$4	$0	$22	$349
FEW	$0	$0	$0	$0	$0
Total	$1,620	$18	$0	$108	$1,746
2015					
FEI	$1,512	$14	$0	$101	$1,627
FEVI	$378	$4	$0	$25	$407
FEW	$0	$0	$0	$0	$0
Total	$1,890	$18	$0	$126	$2,034
2016					
FEI	$1,728	$14	$0	$115	$1,858
FEVI	$432	$4	$0	$29	$464
FEW	$0	$0	$0	$0	$0
Total	$2,160	$18	$0	$144	$2,322
2017					
FEI	$1,512	$14	$0	$101	$1,627
FEVI	$378	$4	$0	$25	$407
FEW	$0	$0	$0	$0	$0
Total	$1,890	$18	$0	$126	$2,034
2018					
FEI	$1,296	$14	$0	$86	$1,397
FEVI	$324	$4	$0	$22	$349
FEW	$0	$0	$0	$0	$0
Total	$1,620	$18	$0	$108	$1,746
Grand Total	**$9,180**	**$90**	**$0**	**$612**	**$9,882**

4.5.9 Mechanical Insulation Pilot

Program Description	The Mechanical Insulation Retrofit project is expected to commence in 2013, and is designed to identify and evaluate the energy savings associated with mechanical insulation retrofits in multi-family residential buildings. The project will be a collaboration among FortisBC, building owners and managers, and consultants. Failure to comply with mechanical insulation building codes and best practices results in wasted or excess natural gas consumption. Mechanical insulation retrofits will include the following measures: heating pipes insulated with 1 ½" thick fiberglass; domestic hot water systems pipes 2" and larger will be insulated with 1 ½" thick fiberglass insulation; piping less than 2" will be insulated with 1" thick fiberglass insulation; all insulation will be covered with service jackets and PVC fitting covers; and valves for both the heat and hot water systems will be insulated with the same thickness as the adjoining pipes. An estimated 1,400,000 GJ could be saved annually by performing mechanical insulation retrofits and improving practices and standards on new multi-unit residential buildings. This pilot is planned to commence in 2013 and is projected to deliver validated measurement data by 2015. This may provide input for a potential prescriptive Commercial program to launch in 2016.	
Target Market	Commercial - Medium and Large MURBs	
New vs. Retrofit	Retrofit	
Eligible Measures	Mechanical Insulation Retrofits	
Partners	N/A	
Incremental Cost ($)	$0	Pilot is in development stage. The input data is not available at the time of writing.
Incentive Amount, FortisBC ($)	$0	Pilot is in development stage. The input data is not available at the time of writing.
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	0.0	Pilot is in development stage. The input data is not available at the time of writing.
Elec. Savings per Participant (kWh/yr)	0.0	
Measure Life (years)	N/A	Pilot is in development stage. The input data is not available at the time of writing.
Free Rider Rate (%)	0%	
Spillover Rate (%)	0%	

Mechanical Insulation Pilot (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	0	0	0	0	0
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	0	0	0	0

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
			2014		
FEI	$0	$3	$0	$5	$8
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$3	$0	$5	$8
			2015		
FEI	$0	$3	$0	$5	$8
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$3	$0	$5	$8
			2016		
FEI	$0	$0	$0	$0	$0
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0
			2017		
FEI	$0	$0	$0	$0	$0
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0
			2018		
FEI	$0	$0	$0	$0	$0
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$0	$0	$0	$0
Grand Total	**$0**	**$6**	**$0**	**$10**	**$16**

5 Industrial Energy Efficiency Program Area

5.1 Introduction

For 2014-2018, the suite of Industrial Energy Efficiency Program Area customer offerings has been organized into the following programs:

- The Industrial Optimization program, which includes measures that allow customers to identify, assess and implement custom designed energy-efficiency projects.
- The Specialized Industrial Process Technology program, which includes prescriptive initiatives to encourage the implementation of technologies and best practices targeted at specific industrial processes.

5.2 Selected Highlights

The following changes from the previously-approved 2012-2013 EEC Plan have been incorporated into the 2014-2018 Industrial Energy Efficiency Program Area plan:

- The previously approved Industrial Technology Retrofit and Industrial Energy Audit and Analysis programs were consolidated under the Industrial Optimization Program.
- The Industrial Technology Retrofit program was renamed as Technology Implementation to reflect the inclusion of new construction projects in the Industrial Optimization Program.
- The development and implementation of the Process Heat program has been transferred from the Commercial program area, as it primarily targets industrial customers with boiler systems consuming natural gas for process heat. The initiative was renamed as "Process Boiler System" and now resides under the Specialized Industrial Process Technology program as described below.

In addition to the structural revisions noted above, the plan includes new measures and a new program which were not included in the previous 2012-2013 EEC plan. These are presented below:

- Three new measures are added to the Industrial Optimization Program:
  - **Industrial Assessment:** This measure will encourage industrial customers to perform a one day walkthrough assessment to identify, at a high level, natural gas saving opportunities.
  - **Industrial Sector Study:** This measure will encourage industrial customers to hire a consultant to study efficiency improvements of a specific sector or equipment inside an industrial facility. It differs in this respect from the Industrial Energy Audit and Analysis option which tends to focus more on whole plant studies.
  - **Small Industrial Implementation:** This measure, targeted at small and medium industrial customers, will provide funding towards custom designed projects that don't meet the Technology Implementation requirements.
- The Specialized Industrial Process Technology Program is a new program including incentives for three measures:

- **Steam Distribution:** This prescriptive measure, targeted at facilities using steam for industrial processes, will encourage surveys and the optimization of the steam distribution system by addressing leaks, steam traps and pipe insulation.

- **Process Boiler System:** This prescriptive measure, targeted at industrial customers using boilers for steam or hot water generation, will encourage customers to increase the efficiency of their boilers through retrofits or complete replacement.

- **Wood Drying Process:** This prescriptive measure, targeted at wood drying facilities, will provide funds towards control systems and heat recovery units to increase the efficiency of wood drying process.

Note: The new offerings described above are currently undergoing development. Refer to Section 5.4 Program Profiles, for any additional details

5.3 Overview of Results

Exhibit 11 and Exhibit 12 provides a summary of the estimated savings, program expenditures and cost-effectiveness results for each of the programs noted above and for the Industrial Energy Efficiency Program Area as a whole.

Exhibit 11 - Summary of Expenditures for the Industrial Sector Program Portfolio

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Industrial Optimization Program																		
FEI	996	1,245	1,406	1,464	1,464	6,576	253	298	359	406	432	1,749	1,249	1,543	1,765	1,871	1,897	8,324
FEVI	98	123	139	145	145	650	25	29	35	40	43	173	124	153	175	185	188	823
Total	1,094	1,368	1,545	1,609	1,609	7,226	278	328	394	447	475	1,922	1,373	1,696	1,939	2,056	2,084	9,148
Specialized Industrial Process Technology Program																		
FEI	177	287	342	525	500	1,830	74	74	74	74	74	368	250	360	416	599	573	2,199
FEVI	20	32	38	58	56	203	7	7	7	7	7	36	27	39	45	66	63	240
Total	196	318	380	584	555	2,034	81	81	81	81	81	405	277	399	461	665	636	2,438
Non-Program Specific Expenses																		
FEI	0	0	0	0	0	0	238	238	238	238	238	1,192	238	238	238	238	238	1,192
FEVI	0	0	0	0	0	0	24	24	24	24	24	118	24	24	24	24	24	118
Total	0	0	0	0	0	0	262	262	262	262	262	1,310	262	262	262	262	262	1,310
ALL PROGRAMS																		
FEI	1,173	1,531	1,748	1,990	1,964	8,406	565	610	671	718	744	3,309	1,738	2,142	2,419	2,708	2,709	11,715
FEVI	118	155	177	203	200	854	56	60	66	71	74	327	174	215	243	274	274	1,181
Total	**1,291**	**1,686**	**1,925**	**2,193**	**2,165**	**9,260**	**621**	**671**	**737**	**789**	**818**	**3,636**	**1,912**	**2,357**	**2,662**	**2,983**	**2,983**	**12,896**

Exhibit 12 - Summary of Savings and Cost-Effectiveness Results for the Industrial Sector Program Portfolio

Program and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios				
	2014	2015	2016	2017	2018		TRC	MTRC	Utility	Participant	RIM
Industrial Optimization Program											
FEI	75,787	170,521	277,514	388,965	500,417	3,293,986	2.86	N/A	3.84	4.06	0.79
FEVI	7,495	16,865	27,446	38,469	49,492	331,253	2.89	N/A	3.88	6.77	0.49
Total	83,282	187,385	304,960	427,434	549,909	3,625,239	2.86	N/A	3.84	4.30	0.76
Specialized Industrial Process Technology Program											
FEI	23,744	58,165	103,703	164,746	225,038	1,583,497	4.65	N/A	7.27	5.80	0.88
FEVI	2,638	6,463	11,523	18,305	25,004	179,455	4.77	N/A	7.51	10.00	0.52
Total	26,382	64,628	115,225	183,051	250,042	1,762,953	4.66	N/A	7.30	6.18	0.85
Non-Program Specific Expenses											
FEI	No Direct Savings						No Direct Savings				
FEVI											
Total											
ALL PROGRAMS											
FEI	99,531	228,686	381,217	553,712	725,455	4,877,484	3.02	N/A	4.08	4.49	0.80
FEVI	10,134	23,327	38,969	56,774	74,496	510,708	3.11	N/A	4.21	7.65	0.49
Total	**109,664**	**252,013**	**420,186**	**610,486**	**799,951**	**5,388,192**	**3.03**	N/A	**4.09**	**4.78**	**0.77**

5.4 Program Profiles

The following pages provide profiles for each of the programs shown above in Exhibit 11 and Exhibit 12.

5.4.1 Industrial Optimization Program

Program Description	This program provides financial incentives towards identifying, assessing and implementing customized cost-effective energy-efficiency projects for industrial processes using natural gas as process heat or an energy source. Three options will be available to Industrial clients to identify saving opportunities. Two implementation programs will be available to small, medium and large Industrial customers.	
Target Market	Small, Medium and Industrial Clients	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	Industrial Energy Audit (26%), Industrial Assessment (36%), Industrial sector Study (13%), Technology Implementation (7%), Small Industrial Implementation (18%)	
Partners	N/A	
Incremental Cost ($)	$85,000	Industrial Energy Audit: $34,000, Industrial Assessment: $4,000, Industrial sector Study: $20,000, Technology Implementation[2]: $805,000, Small Industrial Implementation[2]: $85,000 ***Sources:*** Technology Implementation: Based on average of 4 projects, Small Industrial Implementation: Based on other utility offerings.
Incentive Amount, FortisBC ($)	$52,700	Industrial Energy Audit: $21,000, Industrial Assessment: $4,000, Industrial sector Study: $10,000, Technology Implementation[2]: $525,000, Small Industrial Implementation[2]: $40,000 ***Sources:*** Industrial Energy Audit, Industrial Assessment, Industrial sector Study: Based on program's business case and requests from the industry. Technology Implementation: Based on average of 4 current projects, Small Industrial Implementation: Based on a review of similar offerings at other utilities.
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	4,462	Industrial Energy Audit: 0 GJ, Industrial Assessment: 0 GJ, Industrial sector Study: 0 GJ, Technology Implementation: 43,700 GJ, Small Industrial Implementation: 7,500 GJ ***Sources:*** Technology Implementation: Based on average of 4 projects, Small Industrial Implementation: Based on other utility's offerings and a reduction of the project's payback from 2 to 1 years
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	3.3	Industrial Energy Audit: 1 yrs, Industrial Assessment: 1 yrs, Industrial sector Study: 1 yrs, Technology Implementation: 10 yrs, Small Industrial Implementation: 10 yrs ***Sources:*** Industrial Energy Audit, Industrial Assessment, Industrial sector Study: Variable, Technology Implementation and Small Ind. Implementation: Industry Standard
Free Rider Rate (%)	21%	Industrial Energy Audit: 20%, Industrial Assessment: 30%, Industrial sector Study: 20%, Technology Implementation: 10%, Small Industrial Implementation: 10%. ***Source:*** Best Estimate
Spillover Rate (%)	0%	

Industrial Optimization Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	19	23	26	27	27
FEVI	2	2	3	3	3
FEW	0	0	0	0	0
Total	21	26	29	31	31

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$1,127	$166	$30	$55	$1,378
FEVI	$113	$17	$3	$5	$138
FEW	$13	$2	$0	$1	$15
Total	$1,252	$185	$33	$61	$1,531
2015					
FEI	$1,310	$171	$29	$94	$1,605
FEVI	$131	$17	$3	$9	$161
FEW	$15	$2	$0	$1	$18
Total	$1,456	$190	$33	$105	$1,783
2016					
FEI	$1,338	$188	$28	$138	$1,693
FEVI	$134	$19	$3	$14	$169
FEW	$15	$2	$0	$2	$19
Total	$1,487	$209	$32	$154	$1,881
2017					
FEI	$1,394	$193	$28	$181	$1,796
FEVI	$139	$19	$3	$18	$180
FEW	$15	$2	$0	$2	$20
Total	$1,549	$214	$31	$201	$1,995
2018					
FEI	$1,334	$197	$30	$201	$1,762
FEVI	$133	$20	$3	$20	$176
FEW	$15	$2	$0	$2	$20
Total	$1,483	$219	$33	$223	$1,958
Grand Total	**$7,226**	**$1,016**	**$162**	**$743**	**$9,148**

Notes:

1. The numbers used in this plan are based on the values from projects of the technology retrofit and the industrial energy audit programs, as well as informal conversations with energy efficiency consultants and industrial customers and professional experience. Although these values represent the best available information to date, they may not represent future projects participating in the program. However, to ensure the cost effectives of the program, no incentives will be provided for implementation projects having a TRC below 1.0.
2. The incremental costs of the Technology Implementation and Small Industrial Implementation measures are based on the capital costs of energy efficiency upgrade projects. In addition, the incentive amounts for these measures are based on a percentage of the capital costs.

5.4.2 Specialized Industrial Process Technology Program

Program Description	This program provides prescriptive incentives to Industrial customers to encourage the implementation of specific technologies and best practices targeted at particular industrial processes using natural gas as process heat or an energy source.	
Target Market	Industrial Customers	
New vs. Retrofit	Both	
Eligible Measures (% Distribution of Participants)	Steam Distribution Program (14%), Process Boiler System (64%), Wood Drying process (23%)	
Partners	N/A	
Incremental Cost ($)	$63,400	Steam Distribution Program: $9,300, Process Boiler System: $50,000, Wood Drying process: $139,000 ***Sources:*** Insulate Steam Distribution and Condensate Return Lines and Benchmark the Fuel Cost of Steam Generation 2012, U.S. Department of Energy., Understanding Steam Traps 2011, American Institute of Chemical Engineers and internal studies
Incentive Amount, FortisBC ($)	$32,200	Steam Distribution Program: $3,500, Process Boiler System: $25,000, Wood Drying process: $72,500 ***Sources:*** Reducing Energy Costs Through Boiler Efficiency, North Carolina State University. Business Programs: Deemed Savings Manual V1.0 2010, KEMA Inc.
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	4,500.0	Steam Distribution Program: 86 GJ, Process Boiler System: 1,540 GJ, Wood Drying process: 15,000 GJ ***Sources:*** UDE and AICHE Documents, NC University, KEMA Business Programs: Deemed Savings Manual V1.0
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	14.8	Steam Distribution Program: 6 yrs, Process Boiler System: 20 yrs, Wood Drying process: 10 yrs ***Sources:*** Industry and other utility experience and UDE and AICHE Documents, NC University, KEMA Business Programs: Deemed Savings Manual V1.0
Free Rider Rate (%)	18%	Steam Distribution Program: 20%, Process Boiler System: 20%, Wood Drying process: 10%. ***Source:*** Best Estimate
Spillover Rate (%)	0%	

Specialized Industrial Process Technology Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	6	9	10	16	15
FEVI	1	1	1	2	2
FEW	0	0	0	0	0
Total	7	10	11	18	17

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
			2014		
FEI	$174	$24	$24	$24	$246
FEVI	$19	$2	$2	$2	$27
FEW	$0	$0	$0	$0	$1
Total	$193	$27	$27	$27	$274
			2015		
FEI	$284	$24	$24	$24	$357
FEVI	$32	$2	$2	$2	$39
FEW	$0	$0	$0	$0	$1
Total	$316	$27	$27	$27	$397
			2016		
FEI	$344	$24	$24	$24	$417
FEVI	$38	$2	$2	$2	$45
FEW	$0	$0	$0	$0	$1
Total	$382	$27	$27	$27	$463
			2017		
FEI	$527	$24	$24	$24	$600
FEVI	$59	$2	$2	$2	$66
FEW	$0	$0	$0	$0	$1
Total	$586	$27	$27	$27	$667
			2018		
FEI	$502	$24	$24	$24	$574
FEVI	$56	$2	$2	$2	$63
FEW	$0	$0	$0	$0	$1
Total	$557	$27	$27	$27	$638
Grand Total	**$2,034**	**$135**	**$135**	**$135**	**$2,438**

Notes:
1. The numbers used in the design of this program are estimates based on the information available to date. Estimates were obtained from informal conversations with energy efficiency consultants and industrial customers and demonstration projects. Inputs will be updated if empirical results from implemented projects differ from the estimates used.

6 Low Income Energy Efficiency Program Area

6.1 Introduction

This program area was specifically created to meet the needs of low income customers. As per the Demand-Side Measures Regulation, B.C. Reg. 326/2008 (the “DSM Regulation”), a utilities’ DSM portfolio is considered adequate when there is “a demand-side measure intended specifically to assist residents of low income households to reduce their energy consumption”.[6]

Further, one of the EEC program principles is that “programs have a goal of being universal, offering access to energy efficiency and conservation for all residential and commercial customers, including low income...”.[7] The Companies are maintaining their commitment to this principle by offering a set of no-cost or low-cost programs to low income participants.

For 2014-2018, the suite of Low Income Energy Efficiency Program Area customer offerings has been organized into the following programs:

- Residential Energy Efficiency Works (REnEW)
- Energy Saving Kit (ESK)
- Energy Conservation Assistance Program (ECAP)
- Low Income Space Heat Top-Ups
- Low Income Water Heating Top-Ups
- Non-Profit Custom Program

6.2 Selected Highlights

The REnEW, ESK and ECAP programs are all expected to continue to be delivered in partnership with BC Hydro and FortisBC. These partnerships continue to create program delivery efficiencies that reach a greater number of low income participants.

As the ECAP program evolves, we expect that participation barriers will be reduced and program delivery efficiencies will be improved; consequently, we expect that participants will increasingly shift from the ESK Program to the ECAP program. This will be a positive change, as the ECAP program generates significantly larger energy savings and a larger positive impact on low income household’s financial savings, health and safety.

New Low Income initiatives designed with the non-profit housing sector in mind are planned for 2014-2018, and have yet to be approved by the Commission, include:

- **Low Income Space Heat Top-Ups:** Low income customers and housing providers will be able to receive an additional top-up incentive through the Efficient Boiler program if they indicate they are low income.

- **Low Income Water Heating Top-Ups:** Low income customers and housing providers will be able to receive an additional top-up incentive through the Commercial Water Heater program if they indicate they are low income.

[6] DSM Regulation as amended Dec 8, 2011.Section 3.a.
[7] Energy Efficiency and Conservation Programs Application, May 28, 2008, pg 47.

- **Non-Profit Custom Program:** The goal of this program is to identify and provide incentives for deeper energy-efficiency retrofits to low income housing providers and not-for-profit associations.

FortisBC works very closely with the BC Non-Profit Housing Association and these new programs will be developed to address the needs of non-profit housing providers. Further details on these programs can be found in Section 5.3 and in the program profiles in section 6.4 below.

6.3 Overview of Results

Exhibit 13 and Exhibit 14 provides a summary of the estimated savings, program expenditures and cost-effectiveness results for each of the programs noted above and for the Low Income Energy Efficiency Program Area as a whole. Results shown in Exhibit 13 and Exhibit 14 include the 30% benefits adder, as provided for in the demand-side measures regulation for Low Income programs.

It should be noted that providing energy-efficiency and conservation programs for low income customers can be challenging in terms of achieving a positive TRC result, despite the 30% benefits adder. This is because of the relatively high cost of providing conservation services to this important customer segment. The ECAP program, in particular, uses a full-service approach that the Companies believe is required to engage and install energy savings measures within this sector. This required approach makes it very difficult to achieve favourable TRC results in the ECAP program.

Exhibit 13 - Summary of Expenditures for the Low Income Sector Program Portfolio

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Energy Savings Kit																		
FEI	72	65	58	52	47	294	50	45	41	37	33	207	122	110	99	89	81	501
FEVI	24	22	19	17	16	98	13	11	10	9	8	52	37	33	30	27	24	150
Total	96	86	78	70	63	393	63	57	51	46	42	258	159	143	129	116	105	651
Energy Conservation Assistance Program																		
FEI	901	991	1,090	1,199	1,319	5,501	606	668	740	811	891	3,715	1,507	1,659	1,829	2,010	2,210	9,216
FEVI	100	110	121	133	147	611	67	74	82	90	99	413	167	184	203	223	246	1,024
Total	1,001	1,101	1,211	1,333	1,466	6,112	673	743	822	901	990	4,128	1,675	1,844	2,033	2,234	2,456	10,240
REnEW																		
FEI	0	0	0	0	0	0	41	81	81	41	81	324	41	81	81	41	81	324
FEVI	0	0	0	0	0	0	41	0	0	41	0	81	41	0	0	41	0	81
Total	0	0	0	0	0	0	81	81	81	81	81	405	81	81	81	81	81	405
Low Income Space Heat Top-Ups																		
FEI	58	64	71	56	45	295	12	13	14	12	9	60	70	77	85	68	54	355
FEVI	6	7	8	6	5	33	1	1	2	1	1	7	8	9	9	8	6	39
Total	65	71	78	63	50	327	13	15	16	13	10	67	78	86	94	76	60	394
Low Income Water Heating Top-Ups																		
FEI	10	11	12	9	7	49	4	4	4	4	4	20	14	15	16	13	12	69
FEVI	1	1	1	1	1	5	0	0	0	0	0	2	2	2	2	1	1	8
Total	11	12	13	10	8	54	5	5	5	5	5	23	15	16	17	15	13	77
Non-Profit Custom Program																		
FEI	204	224	247	272	299	1,246	81	89	97	107	118	492	285	313	344	379	417	1,738
FEVI	23	25	27	30	33	138	9	10	11	12	13	55	32	35	38	42	46	193
Total	227	249	274	302	332	1,385	89	98	108	119	131	546	316	348	383	421	463	1,931
Non-Program Specific Expenses																		
FEI	0	0	0	0	0	0	268	268	268	268	268	1,342	268	268	268	268	268	1,342
FEVI	0	0	0	0	0	0	37	37	37	37	37	183	37	37	37	37	37	183
Total	0	0	0	0	0	0	305	305	305	305	305	1,525	305	305	305	305	305	1,525
ALL PROGRAMS																		
FEI	1,245	1,355	1,477	1,589	1,718	7,385	1,062	1,169	1,246	1,279	1,405	6,160	2,307	2,524	2,723	2,869	3,123	13,545
FEVI	154	165	177	188	201	886	168	134	142	190	158	792	322	299	319	378	360	1,678
Total	**1,399**	**1,520**	**1,654**	**1,778**	**1,920**	**8,271**	**1,229**	**1,303**	**1,387**	**1,469**	**1,563**	**6,952**	**2,629**	**2,822**	**3,042**	**3,247**	**3,483**	**15,223**

Exhibit 14 - Summary of Savings and Cost Effectiveness Results for the Low Income Sector Program Portfolio

Program and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios				
	2014	2015	2016	2017	2018		TRC	MTRC	Utility	Participant	RIM
Energy Savings Kit											
FEI	7,760	14,745	21,030	26,695	31,817	182,391	5.14	N/A	3.33	12.46	0.57
FEVI	2,587	4,915	7,010	8,898	10,606	61,614	5.90	N/A	3.74	20.08	0.37
Total	10,347	19,659	28,040	35,594	42,423	244,005	5.33	N/A	3.43	14.37	0.52
Energy Conservation Assistance Program											
FEI	6,195	13,007	20,499	28,744	37,814	296,555	0.43	N/A	0.32	1.82	0.22
FEVI	688	1,445	2,278	3,194	4,202	33,610	0.43	N/A	0.32	2.37	0.18
Total	6,883	14,452	22,776	31,937	42,016	330,166	0.43	N/A	0.32	1.88	0.22
REnEW											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Low Income Space Heat Top-Ups											
FEI	2,102	4,414	6,958	8,994	10,622	107,909	2.91	N/A	3.09	3.62	0.70
FEVI	234	490	773	999	1,180	12,297	2.97	N/A	3.15	6.19	0.42
Total	2,335	4,905	7,732	9,993	11,802	120,206	2.92	N/A	3.09	3.88	0.68
Low Income Water Heating Top-Ups											
FEI	614	1,290	2,033	2,628	3,103	23,575	1.39	N/A	3.29	1.62	0.71
FEVI	68	143	226	292	345	2,667	1.41	N/A	3.33	2.79	0.42
Total	682	1,433	2,259	2,920	3,448	26,242	1.39	N/A	3.29	1.73	0.68
Non-Profit Custom Program											
FEI	5,499	11,545	18,195	25,513	33,564	334,972	2.71	N/A	2.01	4.43	0.63
FEVI	611	1,283	2,022	2,835	3,729	38,207	2.77	N/A	2.06	7.40	0.40
Total	6,110	12,828	20,217	28,348	37,294	373,179	2.72	N/A	2.02	4.72	0.61
Non-Program Specific Expenses											
FEI	No Direct Savings						No Direct Savings				
FEVI											
Total											
ALL PROGRAMS											
FEI	22,170	45,000	68,715	92,574	116,921	945,402	0.91	N/A	0.70	2.76	0.37
FEVI	4,188	8,277	12,308	16,218	20,062	148,396	1.14	N/A	0.86	5.27	0.29
Total	**26,357**	**53,277**	**81,024**	**108,792**	**136,982**	**1,093,798**	**0.94**	N/A	**0.72**	**3.06**	**0.36**

6.4 Program Profiles

The following pages provide profiles for each of the programs shown above in Exhibit 13 and Exhibit 14.

6.4.1 Energy Savings Kit

Program Description	The goal of this program is to reach a broad audience of low income customers and enable them to take some simple steps towards saving energy by installing a bundle of easy-to-install items that are delivered to their door. Promotional activities will include bill inserts, print ads, direct mail, and partnerships with government ministries and non-profits that serve the low income population.	
Target Market	Low Income Customers	
New vs. Retrofit	Retrofit	
Eligible Measures	Bundle of measures, including low-flow fixtures, water heater pipe wrap, caulking, draft proofing tape, outlet gaskets, and window film.	
Partners	BC Hydro	
Incremental Cost ($)	$14	Based on actual costs of $13.51 in 2012.
Incentive Amount, FortisBC ($)	$14	
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	2.0	Average savings derived from 2010 Conservation Potential Review and third-party studies.
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	8.0	Average based on expected life of each individual measure.
Free Rider Rate (%)	27%	Based on 2010 BC Hydro participant survey.
Spillover Rate (%)	0%	

Energy Savings Kit (cont'd…)

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	5,315	4,784	4,305	3,880	3,508
	FEVI	1,772	1,595	1,435	1,293	1,169
	FEW	0	0	0	0	0
	Total	7,087	6,378	5,740	5,174	4,677

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$72	$30	$19	$2	$122
	FEVI	$24	$7	$5	$1	$37
	FEW	$0	$0	$0	$0	$0
	Total	$96	$37	$23	$3	$159
	2015					
	FEI	$65	$28	$17	$0	$110
	FEVI	$22	$7	$4	$0	$33
	FEW	$0	$0	$0	$0	$0
	Total	$86	$35	$22	$0	$143
	2016					
	FEI	$58	$24	$15	$2	$99
	FEVI	$19	$6	$4	$0	$30
	FEW	$0	$0	$0	$0	$0
	Total	$78	$30	$19	$2	$129
	2017					
	FEI	$52	$23	$14	$0	$89
	FEVI	$17	$6	$4	$0	$27
	FEW	$0	$0	$0	$0	$0
	Total	$70	$28	$18	$0	$116
	2018					
	FEI	$47	$20	$12	$1	$81
	FEVI	$16	$5	$3	$0	$24
	FEW	$0	$0	$0	$0	$0
	Total	$63	$25	$15	$2	$105
	Grand Total	**$393**	**$155**	**$97**	**$6**	**$651**

6.4.2 Energy Conservation Assistance Program

Program Description	This program will enable deep energy savings in low income customer facilities that have moderate to high energy consumption. Promotional activities will include bill inserts, print ads, customer endorsements, and partnerships with government ministries, housing providers, and other organizations that serve the low income populations.	
Target Market	Low Income Residential Customers	
New vs. Retrofit	Retrofit	
Eligible Measures	Bundle of customized measures, which may include low-flow fixtures, water heater pipe wrap, professional draft proofing, outlet gaskets, window film, insulation, improved ventilation, and CO detectors.	
Partners	BC Hydro	
Incremental Cost ($)	$810	Based on expected average cost of the customized bundle of measures installed
Incentive Amount, FortisBC ($)	$810	Based on expected average cost of the customized bundle of measures installed
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	5.8	Based on expected savings for the customized bundle of measures installed
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	13.0	Based on average expected life of the customized bundle of measures installed
Free Rider Rate (%)	4%	
Spillover Rate (%)	0%	

Energy Conservation Assistance Program (cont'd…)

Participants	Service Region	2014	2015	2016	2017	2018
	FEI	1,113	1,223	1,346	1,481	1,629
	FEVI	124	136	150	165	181
	FEW	0	0	0	0	0
	Total	1,236	1,359	1,495	1,645	1,810

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$901	$485	$91	$30	$1,507
	FEVI	$100	$54	$10	$3	$167
	FEW	$0	$0	$0	$0	$0
	Total	$1,001	$539	$101	$34	$1,675
	2015					
	FEI	$991	$563	$106	$0	$1,659
	FEVI	$110	$63	$12	$0	$184
	FEW	$0	$0	$0	$0	$0
	Total	$1,101	$625	$117	$0	$1,844
	2016					
	FEI	$1,090	$592	$111	$37	$1,829
	FEVI	$121	$66	$12	$4	$203
	FEW	$0	$0	$0	$0	$0
	Total	$1,211	$657	$123	$41	$2,033
	2017					
	FEI	$1,199	$683	$128	$0	$2,010
	FEVI	$133	$76	$14	$0	$223
	FEW	$0	$0	$0	$0	$0
	Total	$1,333	$759	$142	$0	$2,234
	2018					
	FEI	$1,319	$713	$134	$45	$2,210
	FEVI	$147	$79	$15	$5	$246
	FEW	$0	$0	$0	$0	$0
	Total	$1,466	$792	$149	$50	$2,456
	Grand Total	**$6,112**	**$3,372**	**$632**	**$124**	**$10,240**

6.4.3 REnEW

Program Description	The goal of this program is to ensure that the energy-efficiency trade in BC is built in a way that enhances communities by enriching the skills of people that are facing barriers to employment. This program provides energy-efficiency trade training by industry experts at no cost to participants.	
Target Market	Marginalized populations and people facing employment barriers	
New vs. Retrofit	N/A	
Eligible Measures	Training	
Partners	N/A	
Incremental Cost ($)	$0	
Incentive Amount, FortisBC ($)	$0	
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	0.0	
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	N/A	Not applicable
Free Rider Rate (%)	0%	
Spillover Rate (%)	0%	

REnEW (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	10	20	20	10	20
FEVI	10	0	0	10	0
FEW	0	0	0	0	0
Total	20	20	20	20	20

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$0	$36	$2	$2	$41
FEVI	$0	$36	$2	$2	$41
FEW	$0	$0	$0	$0	$0
Total	$0	$73	$4	$4	$81
2015					
FEI	$0	$73	$4	$4	$81
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$73	$4	$4	$81
2016					
FEI	$0	$73	$4	$4	$81
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$73	$4	$4	$81
2017					
FEI	$0	$36	$2	$2	$41
FEVI	$0	$36	$2	$2	$41
FEW	$0	$0	$0	$0	$0
Total	$0	$73	$4	$4	$81
2018					
FEI	$0	$73	$4	$4	$81
FEVI	$0	$0	$0	$0	$0
FEW	$0	$0	$0	$0	$0
Total	$0	$73	$4	$4	$81
Grand Total	**$0**	**$365**	**$20**	**$20**	**$405**

6.4.4 Low Income Space Heat Top-Ups

Program Description	This program will encourage non-profit housing societies to replace standard efficiency boilers with high-efficiency boilers. The program will piggyback on the Commercial boiler program; however, it will provide an incentive that is about 30% better. Due to the fact that this program will piggyback on the Commercial space heat program, all cost, energy savings and measure life assumptions are based on the Commercial Space Heat program. The 30% bump to the customer incentive will come from the Low Income program budget. As such, the incremental costs shown here are only 30% of the full incremental costs, the incentive amounts reflect only the 30% bump, and the gas savings only reflect 30% of the total savings from the measure. Promotional activities will be delivered primarily through partnerships with BC Housing, BC Non-Profit Housing Association and other non-profit housing societies.	
Target Market	Low Income Customers	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Condensing boiler (75%), Near condensing boiler (3%), Condensing Rooftop Unit (22%)	
Partners	N/A	
Incremental Cost ($)	$4,453	Condensing boiler: $5,340, Near condensing boiler: $6,210, Condensing Rooftop Unit: $1,200
Incentive Amount, FortisBC ($)	$2,905	Condensing boiler: $3,500, Near condensing boiler: $2,000, Condensing Rooftop Unit: $1,000
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	110.2	Condensing boiler: 131.4 GJ, Near condensing boiler: 250.8 GJ, Condensing Rooftop Unit: 18.8 GJ
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	19.6	Condensing boiler: 20 yrs, Near condensing boiler: 20 yrs, Condensing Rooftop Unit: 18 yrs
Free Rider Rate (%)	5%	Condensing boiler: 5%, Near condensing boiler: 5%, Condensing Rooftop Unit: 5%
Spillover Rate (%)	0%	

Low Income Space Heat Top-Ups (cont'd…)

	Service Region	2014	2015	2016	2017	2018
Participants	**FEI**	20	22	24	19	16
	FEVI	2	2	3	2	2
	FEW	0	0	0	0	0
	Total	22	25	27	22	17

	Service Region	Incentives	Admin	Comm.	Evaluation	Total
Expenditures ($000's)				**2014**		
	FEI	$58	$5	$7	$0	$70
	FEVI	$6	$1	$1	$0	$8
	FEW	$0	$0	$0	$0	$0
	Total	$65	$5	$8	$0	$78
				2015		
	FEI	$64	$5	$7	$1	$77
	FEVI	$7	$1	$1	$0	$9
	FEW	$0	$0	$0	$0	$0
	Total	$71	$6	$8	$1	$86
				2016		
	FEI	$71	$6	$9	$0	$85
	FEVI	$8	$1	$1	$0	$9
	FEW	$0	$0	$0	$0	$0
	Total	$78	$7	$9	$0	$94
				2017		
	FEI	$56	$5	$7	$0	$68
	FEVI	$6	$1	$1	$0	$8
	FEW	$0	$0	$0	$0	$0
	Total	$63	$5	$8	$0	$76
				2018		
	FEI	$45	$4	$5	$1	$54
	FEVI	$5	$0	$1	$0	$6
	FEW	$0	$0	$0	$0	$0
	Total	$50	$4	$6	$1	$60
	Grand Total	**$327**	**$27**	**$39**	**$1**	**$394**

6.4.5 Low Income Water Heating Top-Ups

Program Description	This program will encourage non-profit housing societies to replace standard efficiency water heaters with high-efficiency water heaters. This program will piggyback on the Commercial water heating program; however, it will provide an incentive that is about 30% better. Due to the fact that this program will piggyback on the Commercial water heating program, all costs, energy savings, and measure life assumptions are based on the Commercial water heating program. The 30% bump to the customer incentive will come from the Low Income program budget. As such, the incremental costs shown here are only 30% of the full incremental costs, the incentive amounts reflect only the 30% bump, and the gas savings only reflect 30% of the total savings from the measure. Promotional activities will be delivered primarily through partnerships with BC Housing, BC Non-Profit Housing Association and other non-profit housing societies	
Target Market	Low Income Customers	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Condensing storage and volume type water heater (50%), Near condensing storage and volume type water heater (3%), Condensing on-demand water heater (47%)	
Partners	N/A	
Incremental Cost ($)	$2,334	Condensing storage and volume type water heater: $2,650, Near condensing storage and volume type water heater: $5,860, Condensing on-demand water heater: $1,770.
Incentive Amount, FortisBC ($)	$589	Condensing storage and volume type water heater: $800, Near condensing storage and volume type water heater: $800, Condensing on-demand water heater: $350
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	37.9	Condensing storage and volume type water heater: 47.7 GJ, Near condensing storage and volume type water heater: 22.5 GJ, Condensing on-demand water heater: 28.5 GJ
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	12.0	Condensing storage and volume type water heater: 12 yrs, Near condensing storage and volume type water heater: 12 yrs, Condensing on-demand water heater: 12 yrs
Free Rider Rate (%)	1%	Condensing storage and volume type water heater: 1%, Near condensing storage and volume type water heater: 1%, Condensing on-demand water heater: 1%
Spillover Rate (%)	0%	

Low Income Water Heating Top-Ups (cont'd…)

Participants	**Service Region**	**2014**	**2015**	**2016**	**2017**	**2018**
	FEI	16	18	20	16	13
	FEVI	2	2	2	2	1
	FEW	0	0	0	0	0
	Total	18	20	22	18	14
Expenditures ($000's)	**Service Region**	**Incentives**	**Admin**	**Comm.**	**Evaluation**	**Total**
				2014		
	FEI	$10	$2	$2	$0	$14
	FEVI	$1	$0	$0	$0	$2
	FEW	$0	$0	$0	$0	$0
	Total	$11	$2	$3	$0	$15
				2015		
	FEI	$11	$2	$2	$0	$15
	FEVI	$1	$0	$0	$0	$2
	FEW	$0	$0	$0	$0	$0
	Total	$12	$2	$3	$0	$16
				2016		
	FEI	$12	$2	$2	$0	$16
	FEVI	$1	$0	$0	$0	$2
	FEW	$0	$0	$0	$0	$0
	Total	$13	$2	$3	$0	$17
				2017		
	FEI	$9	$2	$2	$0	$13
	FEVI	$1	$0	$0	$0	$1
	FEW	$0	$0	$0	$0	$0
	Total	$10	$2	$3	$0	$15
				2018		
	FEI	$7	$2	$2	$0	$12
	FEVI	$1	$0	$0	$0	$1
	FEW	$0	$0	$0	$0	$0
	Total	$8	$2	$3	$0	$13
	Grand Total	**$54**	**$9**	**$13**	**$1**	**$77**

6.4.6 Non-Profit Custom Program

Program Description	This program will encourage non-profit housing societies to replace inefficient equipment and systems with high-efficiency solutions. This program will involve an energy study and will provide incentives based on the recommendations of the study. Incentives under this program will cover all of the incremental cost of the cost-effective measures. Promotional activities will include outreach to non-profit housing societies, partnerships with non-profit housing associations, and partnerships with other service organizations working within the non-profit housing sector.	
Target Market	Non-Profit Social Housing Providers (Housing Low Income Customers)	
New vs. Retrofit	Retrofit	
Eligible Measures (% Distribution of Participants)	Energy Study (55%), Capital Incentive (45%)	
Partners	N/A	
Incremental Cost ($)	$24,600	Energy Study: $12,000, Capital Incentive: $40,000 ***Source:*** Average incentives are based on the 5 studies performed in 2012, which revealed opportunities for $40,000 in incremental costs of a bundle of measures.
Incentive Amount, FortisBC ($)	$24,600	Energy Study: $12,000, Capital Incentive: $40,000
Contractor Incentive, FortisBC ($)	$0	
Incentive Amount, Other Source ($)	$0	
Gas Savings per Participant (GJ/yr)	697.5	Energy Study: 0 GJ, Capital Incentive: 1,550 GJ
Elec. Savings per Participant (kWh/yr)	0	
Measure Life (years)	9.6	Energy Study: 1 yrs, Capital Incentive: 20 yrs
Free Rider Rate (%)	5%	Energy Study: 5%, Capital Incentive: 5%
Spillover Rate (%)	0%	

Non-Profit Custom Program (cont'd…)

Participants

Service Region	2014	2015	2016	2017	2018
FEI	8	9	10	11	12
FEVI	1	1	1	1	1
FEW	0	0	0	0	0
Total	9	10	11	12	14

Expenditures ($000's)

Service Region	Incentives	Admin	Comm.	Evaluation	Total
2014					
FEI	$204	$68	$8	$4	$285
FEVI	$23	$8	$1	$0	$32
FEW	$0	$0	$0	$0	$0
Total	$227	$76	$9	$4	$316
2015					
FEI	$224	$75	$9	$4	$313
FEVI	$25	$8	$1	$0	$35
FEW	$0	$0	$0	$0	$0
Total	$249	$84	$10	$5	$348
2016					
FEI	$247	$83	$10	$5	$344
FEVI	$27	$9	$1	$1	$38
FEW	$0	$0	$0	$0	$0
Total	$274	$92	$11	$5	$383
2017					
FEI	$272	$91	$11	$5	$379
FEVI	$30	$10	$1	$1	$42
FEW	$0	$0	$0	$0	$0
Total	$302	$101	$12	$6	$421
2018					
FEI	$299	$100	$12	$6	$417
FEVI	$33	$11	$1	$1	$46
FEW	$0	$0	$0	$0	$0
Total	$332	$111	$13	$7	$463
Grand Total	**$1,385**	**$464**	**$55**	**$27**	**$1,931**

Notes:

1. The numbers presented in this plan are based on values observed in a pilot of 5 non-profit housing participants . While the values above represent the best available information to date they may not be representative of program results over the longer term as these are strongly driven by the specific projects participating in the program at any given time. It should be understood, however, that under the program rules incentives will be provided only after savings have been estimated in energy studies performed by third-party firms. Therefore, controls are in place to ensure incentives are offered on only cost effective measures.

7 Conservation Education and Outreach Initiatives

7.1 Introduction

The Conservation Education and Outreach (CEO) Initiatives provide general conservation and non-program specific communications. CEO Initiatives support the EEC's portfolio goals of energy conservation and GHG emissions reduction established by the Government of BC.

This program area is also intended to foster a culture of conservation within the province by providing education to a broad range of customers, including residential, commercial, and students. The goal of these programs is to ensure that customers learn about taking small steps towards energy conservation so that they will also be receptive to incentive programs when they are proposed.

All of the CEO Initiatives are considered to meet the DSM Regulation s.4(4) and (5), which require the cost effectiveness of "specified demand-side measures" and public awareness programs to be evaluated on a portfolio basis. Specified demand-side measures include education programs for schools or post-secondary institutions, funding of energy-efficiency training and community engagement programs.

For 2014-2018, the suite of Conservation Education and Outreach customer offerings has been organized into the following programs:

- Residential Education
- Commercial Education
- School Education

All of the 2014-2018 programs noted above are a continuation of those presented in the 2012-2013 DSM Plan.

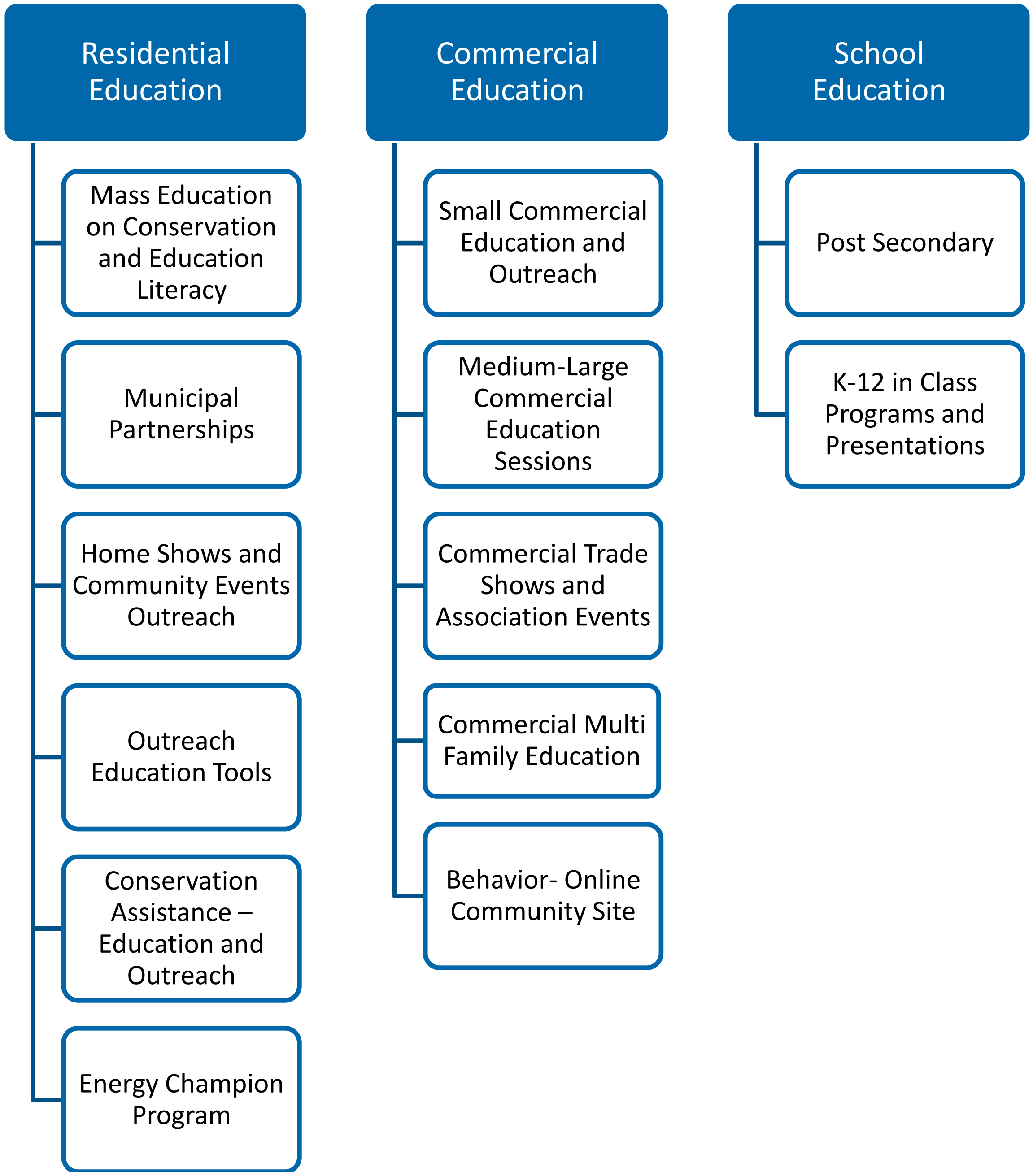
7.2 Program Consolidation

In the 2014-2018 EEC Plan, the CEO Initiatives have placed added emphasis on clustering customer offerings around the major customer segments, instead of by individual initiative. As in the Residential and Commercial sector program areas, this change will allow the FEU to streamline communications strategies. It also enhances customer targeting and messaging activities. More specifically:

- In delivering the programs in 2012 and 2013, it was found that the key educational message for each segment was generally the same. For example, the message of "taking 5 minute showers to save hot water" was the same for Residential Home Shows and Community Events as it was for the Energy Champion program.

Exhibit 15 provides a graphic representation of the revised organization of the CEO customer offerings into three programs.

Exhibit 15 - CEO Program Organization (2014-2018)



7.3 Selected Highlights

In addition to the program organization revisions noted above, the following additional highlights are provided:

- No new programs are being suggested for the CEO program area.
- CEO programs are not individually run through the California Standards Tests at a program level, and traditionally do not have any energy savings directly associated with them. However, some consulting and academic studies estimate that the impact of behaviour

change campaigns range from 0-15%. FEU will continue to explore behavioural change opportunities that may result in energy savings in the Residential and Commercial sectors and will report on this in the EEC Annual Reports to the BCUC.

- A key development in the CEO program area since 2012, and continuing into 2013, was the increased collaboration with the FortisBC Inc. electric utility in an effort to maximize cost effectiveness and efficiency. This included print communications, booth displays and production items for various events and campaigns that occurred in the shared service territory.

- Steps were also taken in 2012 to increase collaboration with BC Hydro in sharing best practices on partnership negotiations and outreach tactics. FEU will collaborate with BC Hydro in 2013 on selected outreach events in pursuit of efficiencies, which will hopefully continue into 2014 and beyond. This growing partnership with other BC utilities also addresses the Commission's directive from the 2012-13 RRA decision to pursue opportunities for increased collaboration on CEO activities.

7.4 Overview of Results

Exhibit 16 and Exhibit 17 provides a summary of the estimated savings, program expenditures and cost-effectiveness results for each of the programs noted above and for the CEO portfolio as a whole.

Exhibit 16 - Summary of Expenditures for the Conservation Education and Outreach Sector Program Portfolio

Program and Service Territory	Utility Expenditures ($1000s)																	
	Incentives						Non-Incentives						All Spending					
	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total	2014	2015	2016	2017	2018	Total
Residential Education Program																		
FEI	0	0	0	0	0	0	891	891	891	891	891	4,455	891	891	891	891	891	4,455
FEVI	0	0	0	0	0	0	99	99	99	99	99	495	99	99	99	99	99	495
Total	0	0	0	0	0	0	990	990	990	990	990	4,950	990	990	990	990	990	4,950
Commercial Education Program																		
FEI	0	0	0	0	0	0	405	405	405	405	405	2,025	405	405	405	405	405	2,025
FEVI	0	0	0	0	0	0	45	45	45	45	45	225	45	45	45	45	45	225
Total	0	0	0	0	0	0	450	450	450	450	450	2,250	450	450	450	450	450	2,250
School Education Program																		
FEI	0	0	0	0	0	0	648	648	648	648	648	3,240	648	648	648	648	648	3,240
FEVI	0	0	0	0	0	0	72	72	72	72	72	360	72	72	72	72	72	360
Total	0	0	0	0	0	0	720	720	720	720	720	3,600	720	720	720	720	720	3,600
Non-Program Specific Expenses																		
FEI	0	0	0	0	0	0	216	216	216	216	216	1,080	216	216	216	216	216	1,080
FEVI	0	0	0	0	0	0	24	24	24	24	24	120	24	24	24	24	24	120
Total	0	0	0	0	0	0	240	240	240	240	240	1,200	240	240	240	240	240	1,200
ALL PROGRAMS																		
FEI	0	0	0	0	0	0	2,160	2,160	2,160	2,160	2,160	10,800	2,160	2,160	2,160	2,160	2,160	10,800
FEVI	0	0	0	0	0	0	240	240	240	240	240	1,200	240	240	240	240	240	1,200
Total	**0**	**0**	**0**	**0**	**0**	**0**	**2,400**	**2,400**	**2,400**	**2,400**	**2,400**	**12,000**	**2,400**	**2,400**	**2,400**	**2,400**	**2,400**	**12,000**

Exhibit 17 - Summary of Savings and Cost-Effectiveness Results for the Conservation Education and Outreach Sector Program Portfolio

Program and Service Territory	Annual Gas Savings, Net (GJ/yr.)					NPV Gas Savings, Net (GJ)	Benefit/Cost Ratios				
	2014	2015	2016	2017	2018		TRC	MTRC	Utility	Participant	RIM
Residential Education Program											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Commercial Education Program											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
School Education Program											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Non-Program Specific Expenses											
FEI	No Direct Savings						No Direct Savings				
FEVI											
Total											
ALL PROGRAMS											
FEI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
FEVI	0	0	0	0	0	0	0.00	N/A	0.00	N/A	0.00
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0.00**	N/A	**0.00**	N/A	**0.00**

7.5 Program Profiles

The following pages provide profiles for each of the programs shown above in Exhibit 16 and Exhibit 17.

7.5.1 Residential Education Program

Program Description	This program will provide information to Residential customers and the general public on natural gas conservation and energy literacy by seeking opportunities to engage with customers directly (either face-to-face or through online programs). This audience will also include low income and ethnic customers. Promotional activities will include print and online communications and engagement campaigns as well as educational seminars, participation in home shows and community events. The Program also includes the cost of production of materials for events and prizing for audience engagement such as 5-minute shower timers or weather stripping samples that are utilized at events targeting Residential customers and children. In addition, continuing partnerships with the regional Canadian Home Builders' Associations and local sports organizations will expand outreach opportunities to engage with Residential customers. Furthermore, FEU will continue to focus on behavioural change opportunities that may result in energy savings. Lastly, collaborations between internal departments and with other utilities will be sought to achieve cost efficiencies in the budget, particularly for advertising and for outreach events.
Target Market	Residential and general public
New vs. Retrofit	Both
Participants[1]	

Service Region	2014	2015	2016	2017	2018
FEI	89,000	89,000	89,000	89,000	89,000
FEVI	10,900	10,900	10,900	10,900	10,900
FEW	100	100	100	100	100
Total	100,000	100,000	100,000	100,000	100,000

Residential Education Program (cont'd…)

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$0	$396	$396	$88	$881
	FEVI	$0	$45	$45	$10	$99
	FEW	$0	$4	$4	$1	$10
	Total	$0	$446	$446	$99	$990
	2015					
	FEI	$0	$396	$396	$88	$881
	FEVI	$0	$45	$45	$10	$99
	FEW	$0	$4	$4	$1	$10
	Total	$0	$446	$446	$99	$990
	2016					
	FEI	$0	$396	$396	$88	$881
	FEVI	$0	$45	$45	$10	$99
	FEW	$0	$4	$4	$1	$10
	Total	$0	$446	$446	$99	$990
	2017					
	FEI	$0	$396	$396	$88	$881
	FEVI	$0	$45	$45	$10	$99
	FEW	$0	$4	$4	$1	$10
	Total	$0	$446	$446	$99	$990
	2018					
	FEI	$0	$396	$396	$88	$881
	FEVI	$0	$45	$45	$10	$99
	FEW	$0	$4	$4	$1	$10
	Total	$0	$446	$446	$99	$990
	Grand Total	**$0**	**$2,228**	**$2,228**	**$495**	**$4,950**

Notes:
1. Indicates the estimated number of customers the program will reach directly through face-to-face and online engagement.

7.5.2 Commercial Education Program

Program Description	This program will provide ongoing communication and education about energy conservation initiatives as well as encouraging behavioural changes that help Commercial customers reduce their organization's energy consumption. The Commercial sector is made up of small and large businesses in a variety of sub sectors such as retail, offices, multi-family residences, schools, hospitals, hospitality services and municipal/institutions. Promotional activities will include print and online communications, event support of industry trade shows, industry association meetings, award events, and development of online tools to assist with education and engagement such as the Cut the Carbon ("C3") online community web site, which engages employees at health authorities and health organizations in carbon-cutting actions and environmental conservation. In addition, the Companies will be furthering partnerships with organizations such as Small Business of BC and Business Improvement Associations of BC, which work with small to medium-sized businesses, and working with Natural Resources Canada to deliver education workshops on natural gas equipment. Lastly, this area will also guide and support behaviour education campaigns delivered by energy specialists (or an energy manager) in their respective organizations. Collaborations between internal departments, as well as with other utilities, will be pursued to achieve cost efficiencies in the budget, in particular on advertising and outreach events.
Target Market	Commercial customers, multi-family, energy specialists, energy management staff
New vs. Retrofit	Retrofit

Participants[1]

Service Region	2014	2015	2016	2017	2018
FEI	13,500	13,500	13,500	13,500	13,500
FEVI	1,500	1,500	1,500	1,500	1,500
FEW	0	0	0	0	0
Total	15,000	15,000	15,000	15,000	15,000

Commercial Education Program (cont'd…)

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$0	$240	$120	$40	$401
	FEVI	$0	$27	$14	$5	$45
	FEW	$0	$3	$1	$0	$5
	Total	$0	$270	$135	$45	$450
	2015					
	FEI	$0	$240	$120	$40	$401
	FEVI	$0	$27	$14	$5	$45
	FEW	$0	$3	$1	$0	$5
	Total	$0	$270	$135	$45	$450
	2016					
	FEI	$0	$240	$120	$40	$401
	FEVI	$0	$27	$14	$5	$45
	FEW	$0	$3	$1	$0	$5
	Total	$0	$270	$135	$45	$450
	2017					
	FEI	$0	$240	$120	$40	$401
	FEVI	$0	$27	$14	$5	$45
	FEW	$0	$3	$1	$0	$5
	Total	$0	$270	$135	$45	$450
	2018					
	FEI	$0	$240	$120	$40	$401
	FEVI	$0	$27	$14	$5	$45
	FEW	$0	$3	$1	$0	$5
	Total	$0	$270	$135	$45	$450
	Grand Total	**$0**	**$1,350**	**$675**	**$225**	**$2,250**

Notes:
1. Indicates the estimated number of customers the program will reach directly through face-to-face and online engagement.

7.5.3 School Education Program

Program Description	This program responds to section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in [K-12] schools and post-secondary schools in the Companies' service area. Activities will include building partnerships and funding support for a variety of in-class and online programs related to conserving energy for K-12 students, delivered both internally and externally by third parties such as non-profit organizations or local sports teams. Some of these programs may include, but are not limited to: Energy is Awesome, Destination Conservation, BC Green Games, Green Bricks, Energy Champion assembly presentations, Vancouver Aquarium Aquaguide, and Beyond Recycling. Some of these programs may also include distribution of low-flow fixtures, shower timers, colouring books, and educational playing cards as part of the program. Partnerships and funding support for post-secondary programs would include in-class programs, in-residence and on-campus education campaigns.
Target Market	Students
New vs. Retrofit	Retrofit
Eligible Measures	N/A
Participants[1]	

Service Region	2014	2015	2016	2017	2018
FEI	45,000	45,000	45,000	45,000	45,000
FEVI	5,000	5,000	5,000	5,000	5,000
FEW					
Total	50,000	50,000	50,000	50,000	50,000

School Education Program (cont'd…)

Expenditures ($000's)	Service Region	Incentives	Admin	Comm.	Evaluation	Total
	2014					
	FEI	$0	$384	$192	$64	$641
	FEVI	$0	$43	$22	$7	$72
	FEW	$0	$4	$2	$1	$7
	Total	$0	$432	$216	$72	$720
	2015					
	FEI	$0	$384	$192	$64	$641
	FEVI	$0	$43	$22	$7	$72
	FEW	$0	$4	$2	$1	$7
	Total	$0	$432	$216	$72	$720
	2016					
	FEI	$0	$384	$192	$64	$641
	FEVI	$0	$43	$22	$7	$72
	FEW	$0	$4	$2	$1	$7
	Total	$0	$432	$216	$72	$720
	2017					
	FEI	$0	$384	$192	$64	$641
	FEVI	$0	$43	$22	$7	$72
	FEW	$0	$4	$2	$1	$7
	Total	$0	$432	$216	$72	$720
	2018					
	FEI	$0	$384	$192	$64	$641
	FEVI	$0	$43	$22	$7	$72
	FEW	$0	$4	$2	$1	$7
	Total	$0	$432	$216	$72	$720
	Grand Total	**$0**	**$2,160**	**$1,080**	**$360**	**$3,600**

Notes:
1. Indicates the estimated number of students the program will reach directly through face-to-face and online engagement.

8 Innovative Technologies Program Area

8.1 Introduction

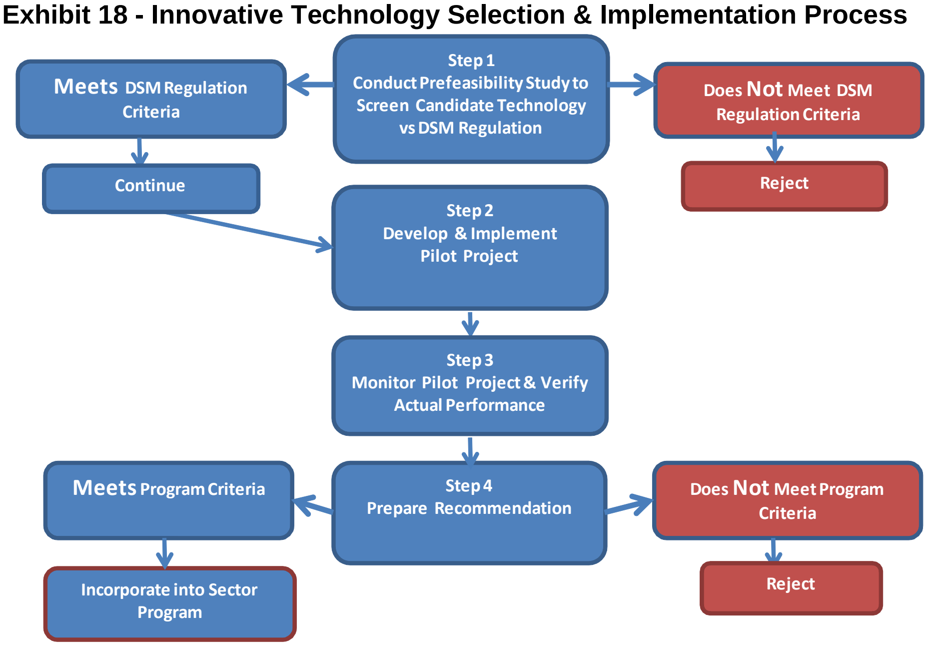
The Innovative Technologies[8] Program Area evaluates market-ready technologies and conducts pilot studies to validate manufacturers' claims related to equipment and system performance. The program area also assesses actual savings and customer acceptance of these newer technologies. Technologies that successfully emerge from the Innovative Technologies Program Area are considered for inclusion within the applicable sector programs within the larger EEC portfolio.

Innovative Technologies are a "specified demand-side measure" under the DSM Regulation, which means that the program and the technologies are only subject to the cost-benefit test at the portfolio level. As such, the expenditures are evaluated as part of the DSM portfolio as a whole. Also, Innovative Technologies are not subject to the 33% portfolio MTRC cap, by Section 4(4) of the Regulation.[9]

8.2 The Innovative Technology Selection & Implementation Process

Exhibit 18 shows the main steps employed in the selection and implementation process for candidate technologies included in the Innovative Technologies program. As illustrated, the process is organized into four main steps:

Exhibit 18 - Innovative Technology Selection & Implementation Process



[8] The DSM Regulation defines a technology innovation program as:
(a) to develop, use or support the increased use of a technology, a system of technologies, a building design or an industrial facility design that is:
(i) not commonly used in British Columbia, and
(ii) the use of which could directly or indirectly result in significant reductions of energy use or significantly more efficient use of energy,
(b) to do what is described in paragraph (a) and to give demonstrations to the public of any results of doing what is described in paragraph (a), or
(c) to gather information about a technology, a system of technologies, a building design or an industrial design referred to in paragraph (a) .

[9] This was confirmed by the Commission in its letter dated July 17, 2012 in response to the FEU's request for clarification ofOrder G-44-12.

- **Step 1: Conduct Prefeasibility Study to Screen Candidate Technologies**
The process begins with the screening of candidate technologies. Prefeasibility studies are used in this step to determine the market availability of the technology, estimate the current adoption rate, evaluate any technical barriers, gather measure assumption data, determine the target customers and assess the market opportunity. The data is used to determine whether the technology meets the requirements of a technology innovation program as defined in the DSM Regulation. Those candidate technologies that do not pass this screen are rejected; those that do pass are considered further through the development of a pilot project.

- **Step 2: Develop and Implement Pilot Project**
Pilot projects are used to gather actual operational experience with the candidate technologies. The development and implementation of a typical pilot project for those technologies that pass Step 1 takes approximately two to three years, depending on the complexities of the pilot design, program controls and participation requirements.

- **Step 3: Monitor Pilot Project and Verify Actual Performance**
A monitoring and verification (M&V) plan is developed for each pilot project. The plan includes details on the monitoring responsibilities, monitoring equipment and meter specifications, procedures for establishing and monitoring the baseline conditions of the site, procedures for monitoring the candidate technology performance, establishing the analysis procedure, and highlighting the reporting period. This step includes the purchase and installation of monitoring equipment, data analysis, and results reporting. This plan complies with the International Performance Measurement & Verification protocol (IPMVP).

  Once the performance data have been compiled over an acceptable period, they are analyzed to determine actual costs and savings as well as any other relevant operational considerations defined in the M&V plan.

- **Step 4: Prepare Recommendation**
A recommendation is prepared based on the results of Step 3. Those pilot technologies that demonstrate acceptable levels of technical performance and cost-effective energy savings are typically considered favourably for inclusion into the applicable sector programs. Those technologies that do not meet those criteria are typically rejected.

8.3 Expenditure Overview

The funding proposed for Innovative Technologies will allocated primarily among three of the activity areas described above:

1. Conducting prefeasibility studies to screen candidate technologies
2. Capital contributions to fund development and implementation of pilot projects deemed to be feasible pursuant to screening study outcomes
3. M&V to confirm savings claims from the pilot projects

Exhibit 19 shows the proposed annual expenditure by activity area over the five-year period.

Exhibit 19 Expenditure by Activity Area

	Expenditures ($1000s)					
Activity Area	***2014***	***2015***	***2016***	***2017***	***2018***	***TOTAL***
Prefeasibility Studies	180	180	180	180	180	900
Pilot Project Expenditures	580	708	867	804	776	3,735
M&V	447	330	186	234	254	1,451
TOTAL	**1,207**	**1,218**	**1,233**	**1,218**	**1,210**	**6,086**

8.3.1 Planned Activities 2014-2018

The following table provides a brief description of the technologies that are being evaluated for pilot projects over the period 2014-2018.

#	Technology	Description
1	Condensing Unit Heaters	Condensing unit heaters are more efficient than their conventional counterparts because they extract additional useful heat out of the latent heat of water vapor in the flue gas. Because natural gas is a hydrocarbon, it produces water vapor as a product of combustion. In a conventional non-condensing boiler, the burner operates at atmospheric pressure and the water vapor is exhausted through the flue along with other combustion products via natural convection. A condensing boiler's rated maximum efficiency increases to about 95% by capturing some of the latent heat of condensation of water vapor in the exhaust stream. This produces a projected 12% increase in efficiency over non-condensing heaters.
2	Radiant Tube Heaters	Radiant tube heaters use a variety of heating element types, such as quartz or carbon tubes, in order to emit radiated heat in a specific direction. Some types use reflectors to focus the heat, while others simply allow the heat to radiate in the direction the heater is facing. Radiant heat provides warmth in the same way that the sun's rays or a warm fireplace does, which means that an object must be within the heater's line of sight to feel the heat. As such, radiant heaters are better suited to heating objects (usually people) than entire spaces. Radiant heaters are particularly effective where the space is frequently unoccupied. Occupants also generally feel warmer at lower ambient air temperatures when heated by radiant heating systems. Energy savings can be realized if thermostat set points are lowered accordingly. Radiant heaters eliminate fan energy required with conventional heating systems. Estimates indicate that radiant tube heaters may save up to 17% of warehouse space heating energy consumption.
3	Recirculating Demand Controls	A standard recirculating pump with no controls continuously moves hot water throughout the recirculation loop to provide the customer with hot water at any fixture without a delay. This method of recirculating hot water wastes energy because the recirculation loop acts as a heat exchanger losing heat to its surroundings. A demand pump is a recirculating pump designed to save energy and water by accelerating the hot water recirculation only when there is demand at a fixture. This pump system is used for domestic hot water recirculation in multi-unit commercial buildings, such as apartments, hotels and offices. Existing installations in the United States show an average 10%-30% savings in natural gas and 84% savings in electricity consumption.

#	Technology	Description
4	Combination Space/Water Heating Units	Combination boilers combine central heating with domestic hot water (DHW) in one device. When DHW is used, a combination boiler stops pumping water to the space heating circuit and diverts the boiler's entire power to heating DHW. Some combination boilers have small internal water storage vessels, combining the energy of the stored water and the gas burner to give faster DHW at the taps or to increase the DHW flow rate. Combination boilers are rated by heat output and the DHW flow rate. High DHW flow-rate models can simultaneously supply two showers. Combination boilers require less space than conventional tanked systems, and are significantly cheaper to install, since water tanks and associated pipes and controls are not required. Another advantage is that more than one unit may be used to supply separate heating zones or multiple bathrooms, providing greater time and temperature control.
5	Residential High-Efficiency Water Heaters	0.80 EF technologies are varied, but four important methods for achieving 0.80 efficiency levels are: (1) On-demand or tankless water heaters heat water only as it is needed. This equipment may incorporate condensing technology with resulting efficiencies higher than 0.90 EF. (2) Condensing water heaters are similar to a standard efficiency gas storage water heater but have an improved heat exchanger that allows thermal efficiency ratings as high as 96% and recovery rates as much as 4 GPM. As such, condensing water heaters can deliver continuous hot water in high demand households. (3) Hybrid systems combine boiler or on-demand heater mounted on or beside a small hot water storage tanks. (4) Combination systems are appliances that perform more than one function, such as providing DHW and space heating within one unit by employing an additional heat exchanger.
6	ENERGY STAR© 0.67 Storage Tank Water Heaters	There are three different water heater types that meet a minimum of 0.67EF-0.70EF available within BC: B-Vent with flue damper, P-Vent (Power Vent), and PD-Vent (Power Direct Vent). As the majority of the market would be targeting B-Vent to B-Vent, the focus is on B-Vent technology. The name B-Vent refers to a traditional "B" type pipe used to evacuate combustion gases. B-Vent water heaters draw air from inside the home through ports in the firebox. Venting occurs through a flue damper which commonly runs out through the roof of the house. B-Vents can use a shared venting pipe, which can also be used by B-Vent boilers or B-Vent furnaces. Habart and Associates Consulting Inc. estimates energy savings to be an annual 2 GJ per installation.
7	Condensing Gas-Fired Ventilation Units	Standard efficiency natural gas-driven ventilation units ensure that buildings meet regulatory ventilation standards. They heat outside air to a specified temperature before it is injected into the building interior. The average efficiency factor for such standard units ranges from 0.78 to 0.82. Condensing units reach an average efficiency factor of 0.91 by employing a heat exchanger in order to remove and put to use excess heat from the exhaust gases that originate in the thermal combustion process. This brings the exhaust gases below their dew point and thus condenses their water vapor component into acidic water. Condensing units are projected to deliver 10% natural gas savings over standard natural gas-driven ventilation units.
8	Fireplace Inserts	Older decorative (non-heating) fireplace inserts can be replaced with new high-efficiency heating appliances to reduce space heating and whole building energy consumption in residential buildings.

#	Technology	Description
9	City of Vancouver Green MURBs	The City of Vancouver has set in motion a Green MURB Pilot intended to encourage carbon reductions through mechanical controls, condensing rooftop units, piping insulation, common area lighting and fireplace and DHW metering. Mechanical ventilation controls are used to save energy through the better management of hydronic heating pumps, outside air temperatures and through optimizing existing hydronic heating and DHW systems. Condensing rooftop units save energy by recovering heat that is ordinarily lost through the exhaust of conventional rooftop units. A condensing rooftop unit uses a heat exchanger to recover heat from the exhaust, improving the overall efficiency of the unit. The use of condensing rooftop units is recognized as a potential energy conservation opportunity. Condensing rooftop units are a relatively new technology in British Columbia and, at the present time, only two manufacturers offer this technology in the province. The estimated market penetration is estimated to be less than 5% for new construction and retrofits. Pipe insulation is used to prevent heat loss and gain from pipes, to save energy and improve effectiveness for thermal systems. Piping insulation will be added on MURBs that don't have insulation on their DHW pipes. This measure will reduce annual natural gas consumption associated with pipe heat loss.
10	Kiln Control	Ordinarily, lumber kilns use traditional pneumatic controls and manual assessments of lumber conditions (dry and wet bulb temperature, elapsed drying time) to produce final dried lumber products. Advanced energy management systems are able to adapt the drying schedule based on the usual control metrics, while also accounting for measured humidity, fuel and electrical consumption, to precisely control drying rate, venting and circulation fan speed for optimal energy consumption and drying quality.
11	Ozone Commercial Laundry	The ozone laundry system is a piece of equipment added onto a new or existing commercial washing machine. The add-on system generates ozone, a naturally occurring molecule that helps clean fabrics by chemically reacting with soils in cold water. Adding an ozone laundry system reduces the amount of chemicals, detergents and hot washing and drying times, producing considerable energy savings. Individual case studies suggest average 43% reductions in hot water consumption for commercial laundry facilities.
12	De-aerator Vent Steam Recovery	Ordinary de-aerator vents generally use an atmospheric vent line that expels excess steam and non-condensable gases dissolved in the boiler feed water. This means that energy is lost via the hot steam and gases expelled from the vent. Modifications would allow for the vent to be rerouted to the hot well, which collects boiler feed water. This uses excess steam and hot gases to pre-heat the boiler feed water, lessening the heat load on the de-aerator. Hotter feed water also has less capacity for dissolved gases. Non-condensing gases can vent from the existing hot well vent.
13	Residential HVAC Zoning	Most residential HVAC systems treat the home as a single zone. Single zone control consists of one thermostat located in a central area of the house that controls HVAC operation. In a single zone system, all of the vent registers are open, distributing air into all areas of the house at once. Single zone control wastes energy because all rooms are being conditioned even when they are not occupied and individual rooms may not be kept at a temperature comfortable for their occupants. Improved control across multiple zones can be achieved via the use of multiple thermostats, variable HVAC fans, ducts and vents.
14	Thermal Bridging Measures	Design and/or installation measures that reduce thermal bridges in building envelopes.

#	Technology	Description
15	Water Spray Kiln Misting System	There are two types of lumber kilns: specialty kilns and dimensional lumber kilns. Specialty lumber kilns complete the lumber drying process by introducing high heat provided by air heaters and moisture provided by stream boilers. If wood is dried without the introduction of moisture the wood can split and crack. The ideal condition for drying is produced by maintaining a relative humidity of as close to 100% as possible. The problem with the current process is that the humidification process (steam) also introduces heat. This makes control difficult and requires the removal of excess heat. Opening and closing dampers for heat removal affects the relative humidity and the outcome is wasted energy and poor quality control. Water spray misting systems are a relatively new method and consist of high-pressure water being pushed through very fine spray nozzles, creating a very fine mist or fog. This mist is so fine that it immediately evaporates and thereby raises the relative humidity in the kiln. As opposed to steam, which adds heat to the kiln, the mist actually adsorbs heat as it evaporates. This allows control of the kiln temperature by adding heat directly via the air heater. According to a report conducted through Catamount Consulting, and verified by our technical support team and ICF Marbek, substantial natural gas savings may be associated with the adoption of this measure. Catamount Consulting claims that primary natural gas savings are due to the reduced need for steam in the drying process. Additional gas and electric savings are associated with reducing the overall kiln run time by 15%.
16	Occupancy Sensors for MURBs	Occupancy sensors automatically turn off lighting, HVAC, and/or electricity once a room is vacant. The occupancy sensors can be installed on the wall or the ceiling based on room size and recommended coverage. For space heating, occupancy sensors apply to MURBs that use either hydronic baseboards that can be set back, or ventilation air that is provided directly to the suite whose fan can be controlled. According to a recent study conducted by ICF Marbek on behalf of FortisBC, Enbridge and SaskPower, occupancy sensors represent a significant opportunity for gas savings for MURBs with claims of up to 20% per installation.
17	Ice Rink Efficiency	REALice, a Swedish technology now widely applied in Switzerland, generates natural gas and electricity savings because hot water is not required in the ice making process. Besides the energy and electricity savings, the result of this process is a harder and better ice surface.
18	Air Curtains	Air curtains are mechanical devices that blow a stream of air across a passageway to reduce heat and moisture transfer between conditioned and non-conditioned spaces. Manufacturers design these devices to replace many of the functions otherwise handled by solid doors, including reduced infiltration of dirt, air pollutants, insects and wind gusts. Applications range in size from drive-through windows to large truck dock doors, but systems are most commonly seen over entranceways to commercial buildings such as supermarkets.
19	Transpired Solar Collectors	Transpired solar collectors pre-heat ventilation supply air by using solar energy. They work by transforming the exterior façade of a building into a solar absorber. The main components include an absorber plate, a perforated exterior surface, an air space, and an intake fan. These components are typically located on the roof or south-facing surfaces (in the Northern hemisphere) to maximize exposure to incidental solar energy. The perforated plate acts as a means for air to pass through the exterior surface and into the air space, which is in contact with the solar absorber. The absorber is typically painted black and is heated by incoming solar energy. This heat is then transferred to the supply air in the air space. This pre-heated air is ducted into the supply air intake of the building's mechanical system to provide tempered outdoor air. The technology can be applied to new or retrofit conditions.

#	Technology	Description
20	Ceramic Manufacturing Microwave Assist	Microwave assist technology (MAT) is a dual fuel or hybrid process developed for the ceramics industry. MAT is applied during the heat treatment process, which exposes the object simultaneously to microwave energy and radiant conventional heat. This technique significantly reduces the heating time as the object experiences volumetric heating through microwaves and convective heating at the same time. The main benefits are reduced energy consumption of about 50% due to reduced heating time of approximately 50% and lowered heating temperature. The quality of the end product is similar or improved when compared to standard convection heating since the object is heated more evenly over the complete profile.
21	Catalytic Radiant Burners	Convection heating is carried out by heating the air surrounding the object to be dried off or cured. This is generally done by having a heating chamber where air is heated and then circulated inside the oven chambers by fans. Normal sources used to heat the inlet air are electricity, gas, steam or oil. One limitation of the convection type oven is that it usually needs to be started 20-30 minutes before actual product operations so that the air inside the oven can reach the required temperature. Unlike convection, which first heats air to transmit energy to the part, IR energy may be absorbed directly by the coating. It may also be reflected or transmitted to the substrate. When the equipment is properly matched with the application, either absorption (to heat the coating) or transmission (to heat the part) may become the primary method used to achieve cure. Because the energy is radiant, IR cure is known to have limitations based on line of sight. That is, the energy only travels in a straight line, to be absorbed by sections of the part facing the source. Catalytic "burners" consist of a porous ceramic material impregnated with a catalyst, such as platinum black, through which a combustible air/natural gas mixture is fed. Typically, the catalytic IR source offers a temperature of 600-1,000°F and an intensity of 2,000 to 7,500 BTU/h per ft^2. They typically appear to have little color during operation, heat up in 180 to 600 seconds and are resistant to thermal and physical shock. Through the catalytic reaction, natural gas and air are converted into infrared heat without combustion or flame.
22	Heat Reflectors	Heat reflectors are PVC panels with an aluminized surface designed to reflect radiant heat. They are installed in between the baseboard/hot water space heater unit and the wall to reduce heat loss and reflect the heat back into the room. This raises comfort levels and enables building occupants to reduce heating requirements in their home.

9 Enabling Activities

9.1 Introduction

Enabling Activities are initiatives that support and supplement the Companies' EEC program development and delivery. These programs, activities and projects provide resources common to the support and delivery of all program area activities.

Most of the activities listed are a continuation from 2013 or a re-application of a study previously conducted in order to get up-to-date information. New activities proposed under enabling activities include a joint market saturation study with BC Hydro and FortisBC Electric, development and maintenance of a home energy-efficiency web portal, and energy management education funding. Further details on these activities can be found in the activity profiles section below.

Note that the activities listed are not individually run through the California Standards Tests and do not have energy savings directly associated with them.[10] However, costs are included at the portfolio level in the overall EEC portfolio TRC.

The suite of Enabling Activities included in this 2014-2018 EEC Plan are:

- EEC Labour
- Efficiency Partners Program
- Codes & Standards
- TrakSmart Maintenance
- Conservation Potential Review
- Residential End-Use Study
- Commercial End-Use Study
- Market Saturation Study
- New Homes Study
- Home Energy-Efficiency Web Portal
- Energy Management Education Funding

[10] The Codes and Standards program area has not claimed any energy savings in this plan but intends to claim energy savings at some point over 2014 to 2018. An explanation for this is included in the Codes and Standards activity profile.

9.2 Activity Profiles

#	Activity Name	Timing	Estimated Cost	Description
1	EEC Labour	2014-2018	$3.5 million/year	Covers all labour costs coded to EEC. Represents 36.7 EEC-funded FTEs (22 reside directly in EEC).
2	Efficiency Partners Program	2014-2018	$500,000/year	This program develops and manages a contractor network to promote EEC programs and energy-efficiency messaging. FEU identifies efficiency partners as equipment manufacturers, service contractors, distributors and retailers, and recognizes the influence these industry groups have with the end-use Residential, Commercial and Industrial customers who make energy-efficiency decisions. This program also supports funding energy efficiency training as outlined in the DSM Regulation.
3	Codes & Standards	2014-2018	$35,000/year	Utilities have a unique understanding of energy supply and customer demand cycles, which can be of assistance in the development of codes and standards. The content and timing of code implementation directly affects market transformation in all program areas. FEU's level of regulatory involvement typically includes one of three involvement classifications: monitoring, stakeholder engagement and developing regulations. The Codes & Standards area "supports the development of or compliance with specified standard or a measure respecting energy conservation or the efficient use of energy" as referred to in the definition of "specified demand-side measures" in the DSM Regulation. Compared to previous years, FEU is seeking a slightly increased budget as it expects to see increased work over this period in research and development, training and awareness as it pertains to building codes, and envelope design along with equipment/appliance standards. FortisBC believes its work in helping to advance national, provincial and municipal level codes and standards does generate energy savings. At this time, the Companies are exploring methodologies with which we can reasonably and effectively measure and claim the energy savings resulting from this activity. As we have not yet determined a methodology for measuring these savings, we have not claimed such savings to date but may do so in 2014 or later. The Companies will continue to investigate options for measuring and attributing savings from codes and standards work and will claim such savings when an appropriate methodology can be identified. Note that savings claims would accrue to the programs supporting the codes/standards.
4	TrakSmart Maintenance	2014-2018	$80,000/year	Ongoing IT maintenance costs related to the EEC TrakSmart program and portfolio DSM tracking system. $60k for unlimited technical support, plus $20k for software protection/upgrade subscription.

#	Activity Name	Timing	Estimated Cost	Description
5	Conservation Potential Review	2015	$500,000 one-time	FEU considers the CPR to be an important tool for use in developing, supporting, and assessing current and future EEC expenditure applications, as well as for directional input into program development. The purpose of a CPR study is to examine available technologies and determine their conservation potential, which includes the amount of energy savings that can be achieved through energy-efficiency and conservation programs over the study period. The CPR does this by comparing the economic and achievable potential of viable measures to a base case scenario. FEU plans to conduct its next CPR in 2015 and is planning to do so in collaboration with FortisBC Inc. (electric) and BC Hydro.
6	Residential End-Use Study (REUS)	2016	$55,000 one-time	The REUS provides a snapshot of the FortisBC Residential customer base. It provides information about the building characteristics, the fuel choice for heating, cooling and cooking, the types and ages of appliances installed, energy-use behaviours, and customer attitudes towards energy issues. The REUS also includes a billing analysis to determine natural gas consumption by appliance type. This study is shared with other FEU departments. The cost listed here represents only EEC's portion.
7	Commercial End-Use Study (CEUS)	2017	$30,000 one-time	The CEUS provides a snapshot of the FortisBC Commercial customer base including multi-family residential buildings. The survey collects information about the building, the business(es) occupying the building, the fuel choice for heating, cooling and cooking, the types and ages of appliances installed, energy-use behaviours, and customer attitudes towards energy issues. This study is shared with other FEU departments. The cost listed here represents only EEC's portion.
8	Market Saturation Study	2014-2015	$300,000 one-time	This study would be in collaboration with BC Hydro and FortisBC Inc. (electric) to construct a market baseline of the installation saturation rates of the different energy end-use technologies currently operating in commercial buildings and small-medium industrial facilities in BC. The results of the study would be used to better understand the opportunities for DSM program interventions, provide a basis for later comparisons of the status of the market in order to help evaluate the impact of DSM programs and codes and standards, and serve as an input to help calibrate the CPR.
9	New Homes Study	2017	$30,000 one-time	The New Home Study is similar to the REUS, except that it focuses on homes built in the previous five years, while the REUS looks at the total housing stock. The aim of the study is to determine emerging trends in new construction: building characteristics, fuel choice for heating, cooling and cooking, types and ages of appliances installed, energy-use behaviours, and customer attitudes towards energy issues.
10	Home Energy Efficiency Web Portal	2014-2018	$100,000/year	This project will develop a home energy-efficiency web portal with content, energy saving tips, online calculators, and a "one-stop rebate shop" for the entire Province of BC. Partners would include the provincial government, BC Hydro and FortisBC Inc. (electric). Budget will cover building of the site, communications to launch the site, and ongoing support of a "community" manager to keep the content fresh and programs updated.
11	Energy Management Education Funding	2014-2018	$150,000/year	Funding to support post-secondary energy management programs such as the UBC Masters in Clean Energy and the BCIT Sustainable Energy Management Advanced Certificate.

10 Summary

The information presented in this EEC Plan provides:

- A comprehensive suite of programs for each of the previously approved EEC activity areas.
- Descriptions of each of the programs, including target markets, eligible measures, expected levels of participation, energy savings and forecast expenditures by administrative category.
- A full reporting of the cost effectiveness of those programs at the level of individual program, program area and total portfolio.

The EEC plan illustrates that there remain significant cost-effective opportunities for energy efficiency within FortisBC's service territory, which is consistent with the results provided in FortisBC's Conservation Potential Review 2010[11] and the previous EEC Plan Report for 2012-2013. This remaining opportunity reflects, in part, how the continued technology cost and performance improvements have increased the availability of energy-efficiency options. This is particularly the case in the Commercial sector. The CPR 2010 study concluded that this sector accounted for more than 40% of the total near term achievable energy savings potential; this emphasis is reflected in the current EEC plan, which forecasts that about 40% of the NPV savings for 2014-2018 will be from the Commercial sector programs.

However, some markets are challenged. More specifically:

- The scope for program-induced natural gas savings in the Residential sector are challenged by the impacts of new space and water heating equipment performance standards, as well as those due to new residential construction standards. Consequently the residential program portfolio has a TRC value of 0.71.
- The low income portfolio is somewhat challenged as well, with a TRC of 0.94. This is due largely to the labour intensive nature of the programs relative to the size of available energy savings.

Overall, the portfolio of programs contained in the EEC Plan provide a TRC value of 0.93, which is almost positive. Based on section 4(1.1) of the DSM Regulation, the Modified TRC (MTRC) has been calculated for the measures with a TRC below 1.00. Section 4(1.5) of the amendment limits expenditures on measures that require the MTRC to be cost effective to 33% of the total DSM portfolio expenditure. Based on the cost-effectiveness results presented herein, the expenditures for these programs total $42,856,000[12] over the test period, which represents only 24% of the total DSM portfolio expenditures. Considering the MTRC adder only for the programs that require it, the portfolio cost effectiveness was calculated at 1.30.

[11] The annual energy savings reported in CPR 2010 include the cumulative effects of technologies implemented in prior years, which provides an accurate comparison with FortisBC's load forecast. However, the annual savings calculation method used for the purpose of this EEC Plan does not include the effects of those prior year technologies. Consequently, the reported savings from each approach are not directly comparable.

[12] Based on 2014 dollars. Does not include inflation.

Attachment I2

FEU 2012 EEC ANNUAL REPORT

FORTIS BC™

Diane Roy
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March 28, 2013

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Erica M. Hamilton, Commission Secretary

Dear Ms. Hamilton:

Re: FortisBC Energy Utilities[1]

Energy Efficiency and Conservation Program - 2012 Annual Report

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Attached please find the Energy Efficiency and Conservation Program – 2012 Annual Report (the "Report") for the FortisBC Energy Utilities.

If you have any questions regarding the information contained in the Report, please contact Ken Ross, Integrated Resource Planning Manager at 604-576-7343. .

Yours very truly,

on behalf of the FORTISBC ENERGY UTILITIES

Original signed by: Ilva Bevacqua

For: Diane Roy

Attachment

cc: EEC Stakeholder Group

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1 comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy Whistler Inc. ("FEW").

The FortisBC Energy Utilities

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

Energy Efficiency and Conservation Program - 2012 Annual Report

March 28, 2013

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1 REPORT OVERVIEW

The FortisBC Energy Utilities ("FEU" or the "Companies"),[1] are committed to delivering a broad portfolio of cost-effective Energy Efficiency and Conservation ("EEC") measures that address the expectations of customers while meeting the requirements for public utilities to pursue cost-effective demand-side measures ("DSM"). Overall, this Report demonstrates that the FEU were successful in achieving their EEC goals for 2012, both in terms of cost-effectiveness and progress. While the FEU's EEC programming continues to evolve, the evidence demonstrates that the FEU have come a long way in retaining qualified staff, developing cost-effective programs and delivering incentives to customers. With an overall portfolio TRC of 1.0 on expenditures of almost $24 million, and numerous programs added, refined or under development, 2012 paved the way for continued success in 2013 and beyond.

1.1 Background

On May 28, 2008, FEI (then TGI) and FEVI (then TGVI) collectively filed their EEC Programs Application (the "EEC Application"), seeking approval of increased funding of EEC programs for the timeframe of 2008-2010. On April 16, 2009, the Commission issued Order No. G-36-09 (the "EEC Decision"), which approved funding of $41.5 million over the 2009-2010 time period ($34.4 million for FEI and $7.1 million for FEVI). A further $32.4 million in EEC expenditure for FEI and $6.1 million for FEVI was approved on November 26, 2009 as part of the Negotiated Settlement Agreements ("NSAs") in the 2010-2011 Revenue Requirements Applications ("RRA") for FEI and FEVI by Commission Order Nos. G-141-09 and G-140-09 respectively.

The Companies subsequently submitted requests for EEC funding for activity over the 2012-2013 time period as part of the 2012-2013 RRA. Commission Order No. G-44-12 approved expenditures of $29.1 million in 2012 and $35.6 in 2013 for existing and new programs.[2] With this Order, the Commission also approved the FEU's request to expand EEC program eligibility to interruptible industrial, FEW and FEI Fort Nelson Service Area customers.

This EEC Annual Report (the "Report") outlines the Companies' actual results and expenditures for 2012 but does not cover any planned activities for the next year, as the Companies submitted a detailed 2012-2013 EEC Plan in the 2012-2013 RRA that is still guiding EEC activity. The format of this Report relies on detailed tables to demonstrate EEC Program results and expenditures.

1 Comprised of FortisBC Energy Inc. ("FEI"), FortisBC Energy (Vancouver Island) Inc. ("FEVI") and FortisBC Energy Whistler Inc. ("FEW").

2 Does not include High Carbon Fuel Switching costs for which the Commission directed FortisBC to treat as current period expenses rather than as EEC expenditures.

1.2 Purpose of Report: Transparency, Accountability and Update on Progress

This Report serves two purposes. First, this Report outlines the Companies' activities in each Program Area and on a portfolio level as requested by the Commission in the EEC Decision. Total Resource Cost ("TRC") calculations and the remaining California Standard Practice Test results (Ratepayer Impact Measure ("RIM"), Participant Cost Test ("PCT"), and Utility Cost Test "UCT") are provided for the overall portfolio and each Program Area in Section 2, and for each program or measure in the respective Program Area sections. In accordance with British Columbia's Demand-Side Measures Regulation, modified TRC ("MTRC") calculations are also provided where appropriate. An explanation of the Portfolio Level MTRC calculation is provided in Section 2.2.

Second, this Report demonstrates that the Companies are meeting the accountability mechanisms accepted by the Commission in Order No. G-36-09. One such mechanism was the requirement to file EEC Annual Reports, which states:

> *"A requirement that Terasen submit annually to the Commission, by the end of the first quarter following year-end, for each year of the funding period, a report on all EEC initiatives and activities, expenditures and results for TGI and TGVI."*

In its decision regarding the 2012-2013 RRA (Order No. G-44-12), the Commission further directed the Companies to continue filing an EEC Annual Report, and to include additional details regarding EEC Stakeholder Group activities. A discussion of the EEC Advisory Group activities is provided in Section 4.

1.3 Organization of the EEC Annual Report

The following describes how each section of the Report presents the results of 2012 EEC activities:

Section 1: Report Overview

- Provides a high-level background for the Report.

Section 2: Portfolio Overview

- Provides a summary and detail regarding the actual 2012 expenditures for EEC activities, along with an explanation of expenditures held in both the EEC deferral account and another deferral account set up for EEC incentive amounts provided to Alternative Energy Services ("AES") projects in which the FEU are a participant.

Section 3: Funding Transfers

- Provides a summary and detail regarding funding transfers that occurred in 2012.

Section 4: EEC Advisory Group Activities

- Provides information regarding EEC Advisory Group ("EECAG") activities in 2012, including a summary of meetings and accountability considerations.

Sections 5 - 9 provide information on:

- Residential Energy Efficiency Program Area;
- Low Income Energy Efficiency Program Area;
- Commercial Energy Efficiency Program Area;
- Innovative Technologies Program Area; and
- Industrial Energy Efficiency Program Area.

Each of the above mentioned sections contain a table summarizing the planned and actual expenditures for the respective Program Area in 2012, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results. Additional tables outline the individual 2012 programs, including program and measure descriptions and a breakdown of non-incentive spending. Details on program closures or planned programs that were not launched in 2012 are also included in these program detail sections.

Section 10: Conservation, Education and Outreach Initiatives

- Provides both summary and detail regarding actual 2012 expenditures for the Conservation, Education and Outreach ("CEO") Program Area.

Section 11: Enabling Activities

- Provides both summary and detail regarding actual 2012 expenditures for the Enabling Activities that support the work of the EEC portfolio as a whole.

Section 12: Evaluation

- Provides both summary and detail regarding pending and actual expenditures for 2012 program evaluation activities, as well as summary results from evaluations and studies completed in 2012.

Section 13: Data Gathering, Reporting and Internal Control Processes

- Provides a summary of the Companies' data tracking, process control and reporting for 2012 EEC activities, and a high level description of the Companies' internal approval process for programs.

Section 14: 2012 EEC Annual Report Summary

- Summarizes the Report and the Companies' 2012 EEC activity.

2 PORTFOLIO OVERVIEW

2.1 Portfolio Level TRC Results

In this Section, the Companies provide their EEC energy savings, expenditures and cost-effectiveness test results on an overall portfolio level for 2012. A summary of the overall portfolio results is provided in Table 2-1, demonstrating that the Companies achieved a portfolio level MTRC result of 1.1 and TRC result of 1.0. EEC expenditures were almost $24 million and recorded natural gas savings were over 450,000 GJ/yr. These are positive outcomes resulting from the Companies' EEC activity over 2012, and the FEU are pleased with the progress made to date.

Table 2-1: Overall EEC Portfolio Results for 2012

Indicator - 2012 Results		Service Territory		Total
		FEI	FEVI	
Annual Gas Savings (GJ/yr.)		404,921	47,642	452,563
NPV of Gas Savings (GJ)		3,026,608	358,465	3,385,073
Utility Expenditures, Incentives ($000s)		12,659	1,765	14,424
Utility Expenditures, Non-Incentives ($000s)		8,083	1,252	9,335
Utility Expenditures, Total ($000s)		20,742	3,017	23,759
Benefit/Cost Ratios	TRC	1.0	1.0	1.0
	MTRC	1.1	1.1	1.1
	Utility	1.5	1.2	1.4
	Participant	2.1	2.4	2.2
	RIM	0.5	0.4	0.5

Table 2-2 provides the cost-effectiveness test results by Program Area for the overall EEC portfolio.

Table 2-2: Overall EEC Portfolio Level Results by Program Area

Portfolio and Service Territory	Annual Gas Savings (GJ/yr.)		NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Portfolio Level Activities														
FEI				0	0	0	3,464	0	3,464					
FEVI	No Direct Savings			0	0	0	581	0	581	No Direct Savings				
Total				0	0	0	4,045	0	4,045					
Residential Sector (includes Enabling Activities)														
FEI	123,987	185,307	1,832,035	5,871	8,733	2,032	1,467	7,902	10,199	1.0	1.2	1.8	1.9	0.6
FEVI	17,232	16,997	168,438	792	832	270	264	1,061	1,096	1.0	1.1	1.5	2.3	0.5
Total	141,218	202,304	2,000,473	6,662	9,564	2,301	1,731	8,963	11,295	1.0	1.2	1.8	1.9	0.6
Low Income														
FEI	27,169	12,432	72,937	2,753	195	1,698	330	4,450	525	1.6	n/a	1.6	n/a	0.5
FEVI	3,019	4,680	27,802	306	45	204	33	519	78	4.6	n/a	4.0	n/a	0.5
Total	30,188	17,112	100,739	3,058	240	1,911	363	4,969	603	2.1	n/a	1.9	n/a	0.5
Commercial Sector														
FEI	272,726	136,815	643,841	6,444	3,346	702	599	7,326	3,945	1.3	n/a	1.5	3.3	0.4
FEVI	49,138	25,926	161,815	995	869	98	51	1,197	920	1.5	n/a	1.7	3.3	0.5
Total	321,863	162,741	805,656	7,439	4,215	800	650	8,523	4,865	1.3	n/a	1.5	3.3	0.4
Innovative Technologies														
FEI	0	367	3,608	0	92	0	261	0	353	0.1	n/a	0.1	1.3	0.1
FEVI	0	39	410	0	9	0	31	0	40	0.1	n/a	0.1	4.0	0.1
Total	0	406	4,018	0	102	0	292	0	394	0.1	n/a	0.1	1.4	0.1
Industrial Sector														
FEI	72,587	70,000	474,187	1,155	293	129	54	1,284	347	2.3	n/a	4.7	2.1	1.4
FEVI	0	0	0	23	10	0	0	24	10	n/a	n/a	n/a	n/a	n/a
Total	72,587	70,000	474,187	1,179	303	129	54	1,308	358	2.3	n/a	4.7	2.1	1.4
Conservation, Education, and Outreach														
FEI				0	0	2,998	1,909	2,998	1,909					
FEVI	No Direct Savings			0	0	337	291	337	291	No Direct Savings				
Total				0	0	3,335	2,200	3,335	2,200					
TOTAL PORTFOLIOS														
FEI	**496,468**	**404,921**	**3,026,608**	**16,223**	**12,659**	**7,559**	**8,083**	**23,960**	**20,742**	**1.0**	**1.1**	**1.5**	**2.1**	**0.5**
FEVI	**69,389**	**47,642**	**358,465**	**2,116**	**1,765**	**909**	**1,252**	**3,138**	**3,017**	**1.0**	**1.1**	**1.2**	**2.4**	**0.4**
Total	**565,857**	**452,563**	**3,385,073**	**18,338**	**14,425**	**8,476**	**9,335**	**27,098**	**23,760**	**1.0**	**1.1**	**1.4**	**2.2**	**0.5**

Notes:

- Throughout this Report, cost-effectiveness test results are reported to one decimal point.
- In the above tables, and throughout this Report, any difference in totals between the Portfolio Overview, Program Areas and individual program tables is due to rounding.
- Portfolio Level Activities are those activities for which the costs cannot be assigned to an individual Program Area such as the program tracking tool, Energy Efficiency and Conservation Advisory Group ("EECAG") activities and EEC Energy Solutions Managers.
- In the above tables, and in the Program Area Results Summary tables, FEW is included in the FEI service territory. This is consistent with the 2012-2013 EEC Plan.
- In the above tables, and throughout this Report, planned annual gas savings and program expenditures may differ from those in the 2012-2013 EEC Plan. This is due to several factors:
    - Programs listed in the 2012-2013 EEC Plan that were not implemented in 2012 were removed from the planned Program Area totals, resulting in revised planned annual gas savings and program expenditures where applicable.
    - In its 2012-2013 RRA Decision, the Commission approved 40 percent of the requested expenditures for new programs in existing Program Areas in 2012. The planned annual gas savings and program expenditures were adjusted accordingly to 40 percent of what was listed in the 2012-2013 EEC Plan. New programs are indicated as "new" above the applicable program tables.
    - The Furnace Replacement Pilot Program in the Residential Energy Efficiency Program Area was not included in the 2012-2013 EEC Plan, and has no planned value for annual gas savings. The Commission approved expenditures of $2 million for this pilot program in the 2012-2013 RRA Decision.
    - A number of Innovative Technologies Program Area activities implemented in 2012 were not listed in the 2012-2013 EEC Plan and therefore have no planned annual gas savings or program expenditures for 2012 (see Section 8).

It is the view of the Companies that the savings reported herein are conservative and lower than the savings experienced in the marketplace as a result of the Companies' EEC activities, causing the cost-effectiveness test results reported to be lower than they would be otherwise, for the following reasons:

- <u>Net to Gross Ratio</u> - The Net-to-Gross ratio that the Companies are using to report energy savings from EEC activity is highly conservative in that it includes the free ridership impact, which serves to reduce reported energy savings, but does not include the energy savings benefits of spillover[3] effect. In the future, the Companies intend to

[3] Free ridership refers to individuals who participate in a program who would have participated in the absence of an incentive. Spillover refers to individuals that adopt efficiency measures because they are influenced by program-related information and marketing efforts, though they do not actually participate in the program. These can be included in the Net-to-Gross ratio employed in the cost-effectiveness analysis to capture the additive effects of spillover to balance the reductive effects of free ridership.

begin incorporating spillover effects on a program-by-program basis, where spillover can be supported, into reporting of energy savings impacts from EEC activity.

- Attribution from Government Regulation – the introduction of many municipal, provincial and federal minimum equipment and system performance standards is supported by the Companies' EEC activity, yet the Companies have not historically claimed any energy savings from the implementation of these standards. It is the intent of the Companies to begin to account for these standards-related savings on a program-by-program basis in the future, where such accounting can be supported, in accordance Section 4(1.4) of the BC Demand-Side Measures Regulation.

- Ramp Up – The Companies have made great strides in expanding their EEC portfolio, and in 2012 achieved a new level of EEC programming. While the bulk of this ramp up period is now past, a number of new programs introduced in 2012 were launched later in the year as a result of the timing of the Commission's 2012-2013 RRA Decision in April 2012. Although program development and design work was underway prior to the release of the Decision, the Companies were not able to actively promote these programs to customers until certainty was provided on which would be approved. This impacted the Companies' ability to attract participants.

- Conservation, Education and Outreach – CEO activities had costs of $2.7 million in 2012. These activities do result in energy savings; however, since these savings remain difficult to quantify, the Companies do not currently attribute energy savings to them. Thus, these benefits are not reflected in the TRC.

- Enabling Activities – Enabling Activities similarly had costs of $0.6 million in 2012 for the Efficiency Partners Program and Codes and Standards work that contribute to energy savings that cannot currently be quantified. Since these savings cannot currently be included in the TRC calculation, the Companies believe the energy savings benefits are higher than reported.

The Companies' EEC activities include a number of specified demand side measures. The Demand-Side Measures Regulation defines "specified demand-side measure" as:

a) a demand-side measure referred to in section 3 (c) or (d),

b) the funding of energy efficiency training,

c) a community engagement program,

d) a technology innovation program, or

e) financial or other resources provided

i. to a standards-making body to support the development of standards respecting energy conservation or the efficient use of energy, or

ii. *to a government or regulatory body to support the development of or compliance with a specified standard or a measure respecting energy conservation or the efficient use of energy in the Province;*

These measures cannot be determined by the Commission to be not cost-effective under the Utility Cost Test. Further, by Section 4(4) of the Regulation, the cost-effectiveness of specified demand-side measures must be determined by the cost-effectiveness of the portfolio as a whole. Specified demand-side measures are therefore not subject to the 33 percent MTRC cap. Section 8 describes the FEU's technology innovation programs, Section 10 describes the FEU's education and community engagement programs and Section 11 describes the FEU's Codes and Standards related EEC activity, all of which are considered specified demand-side measures according to the definition above. In summary, the Companies' 2012 EEC expenditures, including specified DSM, were cost-effective under the BC Demand-Side Measures Regulation.

2.2 Portfolio Level MTRC Calculation and Results

In 2012, the FEU successfully met the conditions of the Province's Demand-Side Measures Regulation, achieving a portfolio MTRC value of 1.1 with 13 percent of the portfolio enabled by the MTRC cost-effectiveness test. While the FEU strive for TRC test results that approach or exceed 1.0 within each program and across all programs, there are benefits to implementing programs that do not meet this threshold. Some of these benefits include making programs available to those customers that would otherwise be underserved (such as low income and residential customers), water savings, increased human health and comfort and economic benefits such as job creation. These benefits were recognized in 2011 amendments to the Demand-Side Measures Regulation, which enable the use of an MTRC. The MTRC uses a zero-emission energy alternative ("ZEEA") as the avoided cost of natural gas and allows for the inclusion of non-energy benefits ("NEBs").

Utilities can implement DSM with TRC values less than 1.0 but that meet an MTRC threshold of 1.0 as long as expenditures on these activities do not exceed 33 percent of the total portfolio expenditure. The FEU refer to this 33 percent as the MTRC Cap. Table 2-3 shows both the TRC and MTRC of those programs that do not meet the TRC, with the MTRC-enabled activity making up 13% of total portfolio spending. Table 2-2 shows that the portfolio MTRC is 1.1, in accordance with the Demand-Side Measures Regulation and the Commission's approval to assess cost-effectiveness on an overall portfolio basis[4].

[4] The Commission approved the assessment of the cost effectiveness using an MTRC of 1 or greater on an overall portfolio basis as part its decision on the 2012-2013 RRA, page 174.

Table 2-3: Programs Subject to MTRC and the Relative Proportion of Portfolio Spending

Measure	TRC	MTRC	Expenditure ($000s) subject to cap	% of Portfolio Spending
ENERGY STAR® Washers and Other Measures for DHW Conservation (FEI)	0.4	1.0	$98	0.4%
ENERGY STAR® Washers and Other Measures for DHW Conservation(FEVI)	0.4	1.0	$35	0.1%
New Construction – EnerGuide 80 and Energy Efficient Appliances (FEI)	0.2	0.4	$205	0.9%
New Construction – EnerGuide 80 and Energy Efficient Appliances (FEVI)	0.2	0.5	$8	0%
Furnace Replacement Pilot Program (FEI)	0.8	1.6	$2,652	11%
Furnace Replacement Pilot Program (FEVI)	0.7	1.3	$127	0.5%
Total	**n/a**	**n/a**	**$3,125**	**13%**

2.3 Meeting Approved Spending Levels

The Companies were successful in cost-effectively spending within approved levels for EEC expenditures. In its 2012-2013 RRA Decision, the Commission approved an EEC spending limit of just over $29 million for 2012 with $15 million of that included in rate base additions for 2012. Any remaining expenditures above this $15 million up to the $29 million spending cap would be recorded in a non-rate base deferral account and the FEU would propose the method of recovery as part of the next RRA. This mechanism functioned well with 2012 EEC expenditures over the approved $15 million immediate addition to rate base by approximately $8.8 million. This amount will remain in the deferral account through 2013 and the method of recovery will be proposed as part of the next RRA.

The Companies also managed their 2012 EEC activity within the funding limits set out by the Commission[5] for each Program Area, with the exception of the funding transfer discussed in Section 4 to assist the delivery of a number of successful Residential programs. Actual spending in each Program Area is shown in Table 2.2 and each of the Program Area Summary Tables (Sections 5 through 10).

2.4 EEC Deferral Account for Alternative Energy Projects

Commission Order No. G-44-12 directed the FEU to hold all EEC incentives that are provided for AES or related technologies for projects in which the FEU are a participant in a separate

[5] Approved funding amounts for each Program Area can be found on page 169 of the Commission's decision.

deferral account. At the end of 2012, the cumulative gross additions to this deferral account were $119 thousand as a result of spending commitments made and reported in previous years that were actually paid out in 2012. No new incentives related to thermal energy projects in which the FEU are participants were committed during 2012, thus there were no further additions to this deferral account.

2.5 Meeting Adequacy Requirements of the Demand-Side Measures Regulation

The Demand-Side Measures Regulation has the following requirements for a utility's portfolio of EEC activity to be considered adequate:

"A public utility's plan portfolio is adequate for the purposes of Section 44.1 (8) c of the Act only if the plan portfolio includes all the following:

a) A demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
b) If the plan portfolio is introduced on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
c) An education program for students enrolled in schools in the public utility's service area;
d) If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area."

The Companies believe that they have met all the requirements for adequacy. There are a number of programs for low income customers, which are discussed in their own section (see Section 7). A number of the Commercial Energy Efficiency programs are intended for use by owners of rental buildings (see Section 8). Similarly, all Residential Energy Efficiency programs are available to rental properties (see Section 5).

In terms of education programs, the Companies fund a variety of initiatives for K-12 students, including BC Green Games, BC Lions Energy Champion School Assembly Presentations and Beyond Recycling. The Companies also fund post-secondary student engagement delivered by Go Beyond and Northwest Wildlife Preservation Society, encouraging students to learn and apply their knowledge of natural gas energy conservation through fun and interactive competitions (see Section 10).

2.6 Collaboration & Integration

The Companies are taking ever-greater steps toward collaboration and integration with both FortisBC Inc., (the electric utility) and BC Hydro, as well as with other entities such as governments and industry associations. The Companies recognize that doing so will maximize program efficiency and effectiveness. Collaborative activity is captured in the individual Program Area sections and program descriptions found in Sections 5 through 11.

As well as program-level collaborative activity, the FEU and BC Hydro entered into a voluntary Memorandum of Understanding (“MOU”) to develop enhanced utility integration in support of government legislation, policy and direction. The 3 year MOU, which was executed in July 2009, and extended for another 3 years in July 2012, provided shared objectives, areas of focus, guiding principles and administrative guidance. A summary report, attached as Appendix A, summarizes key accomplishments achieved during the timeframe of the 2009-2012 MOU.

Another area of collaboration is for the attribution of energy savings from programs that are integrated with other utilities. In its decision on the 2012-2013 RRA, the Commission directed FEU to develop attribution rules for all integrated programs which prevent the double counting of savings[6]. These discussions have been initiated and the Companies intend complete this work in 2013. In 2012, there were no issues with double counting as the Companies only claimed gas savings while to the best of the Companies’ knowledge the electric utilities only claimed electricity savings within the respective utility service territories.

2.7 Summary

The Companies are proud that they have achieved the overall portfolio TRC value of 1.0 and MTRC value of 1.1. The Companies are of the view that both energy savings accounted for in the portfolio and the resulting TRC are conservative. Benefits from additional activities, such as CEO, play a very important role in supporting the development and delivery of programs, while creating a culture of conservation in British Columbia. The Companies expect that with a more complete approach to the Net-to-Gross ratio, the incorporation of attribution from the introduction of government-mandated minimum performance standards, and with the recent changes to the Demand-Side Measures Regulation, the EEC portfolio will be continue to be cost effective.

[6] Section 8.7.2, page 180 of the Commission Decision

3 FUNDING TRANSFERS

The Companies incurred only one funding transfer between Program Areas in 2012. A funding transfer of $2.0 Million was made in 2012 from the Commercial Energy Efficiency Program Area to the Residential Energy Efficiency Program Area. The required transfer was due to greater than forecasted participation in a number of Residential programs, including the Furnace Replacement Pilot Program, LiveSmart BC and the ENERGY STAR Washers Program. Additional detail on these programs is provided in Section 5.3.

The 2012-2013 RRA Decision approved the movement of funding to a maximum of 25 percent from one Program Area to another Program Area for approved programs without prior Commission approval.[7] The funding transfer represents approximately 23 percent of the approved expenditure of $8.8 million for the Commercial Energy Efficiency Program Area, and approximately 22 percent of the approved expenditure of $9.3 million for the Residential Energy Efficiency Program Area. The Companies presented details on the funding transfer to the EECAG for comment and input at the November EECAG workshop, and no concerns were raised by the group (see Section 4 for a summary of EECAG activities in 2012).

[7] Proposed transfers greater than 25 percent of an approved Program Area require prior Commission approval. The transfer of funds to new programs, programs not approved in the 2012-2013 RRA Application or to the Innovative Technologies Program Area continue to require prior Commission approval.

4 EEC ADVISORY GROUP ACTIVITIES

4.1 Overview

As part of the accountability mechanisms established during the 2008 EEC Application regulatory review process, the Companies continue to hold bi-annual workshops with the EECAG, named the EEC Stakeholder Group in EEC reports for previous years. The objective of this advisory body is to provide insight and feedback on the Companies' EEC activities and related issues. This includes EEC program and portfolio performance, development and design; funding transfers; policy and regulations that may impact EEC activities; and other issues and activities as they may arise.

Members may be appointed based on their personal capacity, representation of a common interest shared by stakeholders or representation of a particular organization/group. This representation includes, but is not limited to, governments, geographical regions, First Nations, customers, suppliers, industry associations, non-governmental organizations, research institutes and other groups that have historically intervened in the Companies' regulatory proceedings.

Since the formation of the EECAG in 2009, the Companies have had the opportunity to gain valuable insight on EEC and develop stronger relationships with stakeholders. This input continues to be instrumental as the Companies move forward with EEC activities, helping to ensure that efforts are aligned with the interests of stakeholders.

4.2 Summary of 2012 Workshops

EECAG workshops provide a forum for stakeholders to engage in constructive dialogue with the Companies. Two EECAG workshops were held in 2012, on June 27 ("spring workshop") and November 27 ("fall workshop"). Both took place in Vancouver and were well attended by EEGAG members as well as occasional alternates and guests. Copies of all materials and minutes for these meetings were distributed to EECAG members and other workshop attendees.

4.2.1 SPRING WORKSHOP

During the spring workshop, updates were presented on regulatory, program-specific and other issues. The Companies provided updates on Commission Directives on the 2012-2013 RRA regarding EEC, carbon offsets, the Energy Efficiency Financing ("EEF") Pilot Program and EEC Program evaluation. A representative from the BC Ministry of Energy, Mines and Natural Gas also presented an overview of the Demand-Side Measures Regulation and its requirements. Discussion sessions followed each of these presentations, allowing attendees to both ask clarifying questions and to voice their opinions.

Distinct from the updates was a more participatory breakout session seeking feedback on the EECAG Terms of Reference (“ToR”). This provided attendees with the opportunity to provide general feedback and priority recommendations for the ToR. Both written and verbal feedback was recorded for consideration.

4.2.2 FALL WORKSHOP

The fall workshop centered around gathering feedback on two draft documents: the Evaluation, Measurement & Verification (“EM&V”) Framework and the ToR. Feedback from these discussions was gathered for consideration during the revision of these documents.

Additional updates were presented on the new Home Energy Calculator, Furnace Replacement Pilot Program, Long Term Resource Plan (“LTRP”), gas and electric program integration and On-Bill Financing Pilot Program. As always, these presentations were followed by discussion sessions where feedback was recorded for future consideration.

Following the Furnace Replacement Pilot Program presentation, attendees had the opportunity to express their views on the funding transfer that took place in 2012 between the Commercial and Residential Energy Efficiency Program Areas (see Section 3). No concerns were raised about this funding transfer and the group generally agreed that this practice is acceptable, allowing for greater process efficiency and flexibility. Certain members expressed a desire for more information regarding the issue of potential cross-subsidization of EEC funding between Program Areas/customer groups. This request was noted and will be discussed in greater depth at future meetings.

4.3 Accomplishments

In addition to enabling general constructive dialogue with stakeholders, the 2012 EECAG workshops resulted in several accomplishments. These are summarized below:

4.3.1 TERMS OF REFERENCE

ToR were developed for the EECAG in order to clarify the role, purpose and responsibilities of both members and the Companies. Feedback on the draft ToR was first sought in 2011, and finalization of the document became a priority for 2012. Following extensive consultation with the EECAG during the bi-annual workshops and a final written consultation period, the ToR was finalized in Q1, 2013. Membership in the EECAG will also be formalized through the signing of these ToR in 2013.

Notable outcomes of the EECAG ToR review included the following:

- Decision Making: the EECAG functions as an advisory group, not a decision making body. The goal of discussions is not primarily to reach consensus, but to facilitate open dialogue and obtain feedback on EEC activities.

- Confidentiality: The Companies and EECAG members alike highly value the open and frank discussions that are encouraged during workshops. Confidentiality and the attribution of comments to individual members created some concern; however, in the end the group agreed that confidentiality agreements would restrict the open discussions and therefore confidentiality agreements should not be implemented at this time. Rather, EECAG participation should continue to be based on trust and mutual respect among members.
- Independent Facilitator: Through the ToR discussions, EECAG members raised the idea of having an independent, third-party chairperson or facilitator for EECAG activities. This discussion resulted in the creation of the Independent Facilitator role discussed in more detail in Section 4.3.3 below.
- Membership: the EECAG is intended to be a consortium representing the broad constituency of FEU stakeholders. Members may be appointed based on their personal capacity, representation of a common interest shared by stakeholders or representation of a particular organization/group. There was general consensus that a review of EECAG membership should be conducted on a periodic basis.

4.3.2 EVALUATION, MEASUREMENT & VERIFICATION FRAMEWORK

The Evaluation, Measurement and Verification ("EM&V") Framework documents the background, objectives, principles and general practices that guide the Companies' approach, resources and timeframes for EM&V activities.

The need for such a framework was recognized by the BCUC, which in its decision with respect to the Companies' 2012-2013 RRA provided the following directive:

> *"The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework."*

The EM&V Framework, also a priority for 2012, was introduced conceptually to the EECAG during the spring workshop. The draft Framework was then presented at the fall workshop, where attendees had the opportunity to provide feedback. This feedback was recorded and considered by the Companies. The Framework will be released in a draft format for a final written consultation period in 2013.

4.3.3 INDEPENDENT FACILITATOR

During the spring workshop, EECAG members expressed interest in seeing an independent third party play a role in facilitating group activities. This feedback was recorded and considered by the Companies, which concluded that an Independent Facilitator would be a valuable addition to the EECAG.

At the fall 2012 workshop, the Companies announced their intent to appoint an Independent Facilitator to help ensure that all stakeholders have a fair and balanced opportunity to understand issues and provide input. The responsibilities of the Independent Facilitator include acting as a facilitator at EECAG meetings and advising the Companies on EECAG activity plans, memberships, reporting and other activities as needed.

A representative of the Fraser Basin Council was selected to fill this role based on the nature of the organization's principles of stakeholder engagement as well as the individual experience of the selected representative with both stakeholder engagement and the EECAG. Implementation of the Independent Facilitator role will follow in 2013.

4.4 Feedback & Lessons Learned

In addition to feedback on specific topics presented, EECAG members are encouraged to provide general feedback on the workshops, membership or any other issues. This feedback is typically submitted to the Companies via evaluation forms distributed at each workshop. The results from these evaluation forms are compiled and all comments considered.

Feedback on the 2012 EECAG workshops was largely positive. At both the spring and fall events, 100 percent of evaluation form respondents indicated that they found the workshop interactive and engaging and that they had sufficient opportunity to ask questions and provide input. At the spring workshop, 82 percent indicated that they feel their participation in the EECAG is valued and their input is being considered. This rose to 86 percent at the fall workshop.

Feedback from participants has also been very constructive. Lessons learned from prior meetings have led the Companies to increase their efforts to maximize group participation and feedback through breakout groups and discussion.

Other feedback indicated a strong interest in increased collaboration with First Nations, open dialogue and improved clarity on how feedback is being utilized. The Companies take this feedback seriously and are working hard to make improvements for 2013.

5 RESIDENTIAL ENERGY EFFICIENCY PROGRAM AREA

5.1 Overview

The Residential Energy Efficiency Program Area was successful in reducing annual natural gas consumption by over 200,000 GJ and achieving an overall TRC of 1.0 in 2012. Over $11.3 million was invested in Residential Energy Efficiency upgrades in 2012, 85 percent of which was incentive spending.

Table 5-1 summarizes the projected and actual expenditures for the Residential Energy Efficiency Program Area in 2012, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results. Enabling Activities' expenditures were included in the Residential Program Area in 2012. However, due to the importance of these activities in supporting Residential and all other Program Areas, the Companies have discussed Enabling Activities in a separate section (see Section 11).

Residential programs serve over 860,000 homes in the FEU service territories. For EEC purposes, these customers include end-use customers living in residential single-family homes, row houses, townhomes or mobile homes.[8] These programs serve retrofit and new home applications. Residential programs, in combination with the Companies' education and outreach activities, play an important role in driving the culture of conservation in British Columbia.

[8] Programs for Multifamily Dwellings served under Rate Schedule 2 or 3 are included in the Commercial Energy Efficiency Program Area (please refer to Section 8).

Table 5-1: 2012 Residential Energy Efficiency Program Area Results Summary

Program and Service Territory	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s) Incentives		Non-Incentives		All Spending		Benefit/Cost Ratios				
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
FEI				0	0	0	224	0	224					
FEVI	No Direct Savings			0	0	0	59	0	59	No Direct Savings				
Total				0	0	0	283	0	283					
ENERGY STAR® Domestic Hot Water "DHW" Technologies														
FEI	8,100	874	8,716	486	59	157	39	643	98	0.4	1.0	0.9	0.9	0.4
FEVI	900	436	4,440	54	30	18	5	72	35	0.4	1.0	1.3	1.1	0.4
Total	9,000	1,310	13,156	540	89	175	44	715	133					
Enerchoice Fireplace Program														
FEI	22,599	14,059	121,900	875	714	347	202	1,221	917	2.5	n/a	1.3	n/a	0.4
FEVI	5,301	4,347	39,095	205	234	82	58	287	291	2.7	n/a	1.3	11.9	0.3
Total	27,900	18,406	160,995	1,080	948	428	260	1,508	1,208					
"Give your Furnace/Fireplace Some TLC" – Service Campaign														
FEI				394	428	169	174	563	602					
FEVI	No Direct Savings			44	81	19	23	63	105	No Direct Savings				
Total				438	510	188	197	626	706					
LiveSmart BC - April 1, 2011 through March 31, 2012														
FEI	63,180	106,275	1,080,555	1,610	3,506	432	115	2,042	3,621	1.1	n/a	3.2	n/a	0.7
FEVI	7,020	7,470	77,434	179	243	48	14	227	256	1.1	n/a	3.0	n/a	0.7
Total	70,200	113,745	1,157,989	1,790	3,749	480	128	2,270	3,877					
LiveSmart BC - April 1, 2012 through March 31, 2013 1														
FEI	21,060	30,245	308,408	537	976	144	0	681	976	1.2	n/a	3.2	7.4	0.7
FEVI	2,340	2,833	29,415	60	88	16	0	76	88	1.1	n/a	3.4	5.1	0.7
Total	23,400	33,078	337,823	597	1,064	160	0	757	1,064					
ENERGY STAR® Washers and Other Measures for DHW Conservation														
FEI	4,590	8,899	74,271	153	561	36	48	189	609	1.4	n/a	1.2	2.4	0.4
FEVI	510	779	6,733	17	48	4	3	21	51	1.6	n/a	1.4	2.9	0.4
Total	5,100	9,678	81,004	170	610	40	50	210	660					
Furnace Replacement Pilot Program														
FEI	0	24,473	232,741	1,575	2,322	225	330	1,800	2,651	0.8	1.6	0.9	1.5	0.4
FEVI	0	1,088	10,791	175	103	25	24	200	127	0.7	1.3	0.8	1.6	0.3
Total	0	25,561	243,532	1,750	2,425	250	353	2,000	2,778					
New Construction - EnerGuide 80 and Energy Efficient Appliances														
FEI	4,458	482	5,445	240	167	72	38	312	205	0.2	0.4	0.3	0.9	0.2
FEVI	1,161	44	530	58	5	8	3	66	8	0.2	0.5	0.8	0.6	0.3
Total	5,618	526	5,975	298	171	80	41	378	212					
Enabling Activities														
FEI				0	0	450	274	450	274					
FEVI	No Direct Savings			0	0	50	75	50	75	No Direct Savings				
Total				0	0	500	349	500	349					
On-Bill Financing														
FEI				0	0	0	24	0	24					
FEVI	No Direct Savings			0	0	0	0	0	0	No Direct Savings				
Total				0	0	0	24	0	24					
ALL PROGRAMS														
FEI	**123,987**	**185,307**	**1,832,035**	**5,871**	**8,733**	**2,032**	**1,467**	**7,902**	**10,199**	**1.0**	**1.2**	**1.8**	**1.9**	**0.6**
FEVI	**17,232**	**16,997**	**168,438**	**792**	**832**	**270**	**264**	**1,061**	**1,096**	**1.0**	**1.1**	**1.5**	**2.3**	**0.5**
Total	**141,218**	**202,304**	**2,000,473**	**6,662**	**9,564**	**2,301**	**1,731**	**8,963**	**11,295**	**1.0**	**1.2**	**1.8**	**1.9**	**0.6**

Notes:

- The Residential Program Area exceeded the approved expenditure level by 22 percent or $2.0 million in 2012 due to three major factors:
  - LiveSmart BC invoicing for the LiveSmart BC program iteration launched April 1, 2011 was delayed due to technical issues experienced by the Ministry of Energy, Mines and Natural Gas. Therefore, incentives for retrofits that were completed between April 1, 2011 and December 31, 2011 were not received until the fall of 2012 and were not reported in 2011. The 2011 portion of this expenditure is estimated to be about $1 million.
  - The Furnace Replacement Pilot Program was oversubscribed within eight weeks of the September 1, 2012 launch date resulting in about $780,000 expended over the projected budget. Eighty-seven percent of pilot program expenditures are attributed to customer incentives.

  - In Table 8.4 of the 2012-2013 RRA Decision, the ENERGY STAR® Washers and Other Measures for DHW Conservation Program was listed as a new program, and was approved for only 40 percent of the requested expenditure of $0.5 million. In fact, the program had been in market since April 1, 2011. As a result of the program's success and momentum from 2011 activity, spending on incentives exceeded the approved amount by $440,000.
- The transfer of funds related to these expenditures is outlined in Section 3.
- LiveSmart BC and the ENERGY STAR® Washers and Other Measures for DHW Conservation Program were formerly included in the Joint Initiatives Program Area, but were moved into the Residential Energy Efficiency Program Area as approved in the 2012-2013 RRA Decision. The Furnace Replacement Pilot Program was also approved for inclusion in the Residential Energy Efficiency Program Area.
- See Section 11 for a discussion of the Enabling Activities.

5.2 Residential TRC and MTRC Results

EEC Program Principles state that programs should be universal, offering access to EEC for all customers. Although many Residential EEC programs are challenged in meeting a conventional TRC test in today's low market gas cost environment, these programs, with their broad reach, are cost-effective from a greenhouse gas ("GHG") emissions reduction perspective. This was recognized in the 2011 amendments to the Demand-Side Measures Regulation that enabled the inclusion of lower TRC programs through the application of the MTRC.

Even without the MTRC, the overall 2012 Residential Program Area TRC was 1.0 while the programs evaluated using the MTRC had a combined MTRC result of 1.2. The use of the MTRC enabled three new Residential Energy Efficiency programs to be launched in 2012; the ENERGY STAR® Domestic Hot Water ("DHW") Technologies Program; the New Construction – EnerGuide 80 and Energy Efficient Appliances Program; and the Furnace Replacement Pilot Program.

5.3 2012 Residential Energy Efficiency Programs

Tables 5-2 through 5-10 outline the specific Residential Energy Efficiency programs undertaken in 2012, including program and measure descriptions and a breakdown of non-incentive spending.

Table 5-2: ENERGY STAR® Domestic Hot Water "DHW" Technologies Program Summary (new)

Program Description	This program promotes the replacement of standard efficiency water heaters with efficient ENERGY STAR® models. As part of a longer term market transformation strategy, the program will introduce 0.67 EF storage tank water heaters and new technologies with energy factors (EF) greater than 0.80. The new technologies include condensing and non-condensing tankless water heaters, hybrids and condensing storage tanks. The program is available to both retrofit and new construction markets. The program supports upcoming federal and provincial Efficiency Act Standards for gas and propane-fired water heaters.				
Target Market	Residential customers				
New vs Retrofit	Both				
Eligible Measures	ESTAR 0.67 EF Storage Tank	Non-Condensing Tankless	Condensing Tankless	Hybrids	Condensing Storage Tank
Incremental Measure Cost					
Retrofit	$250	$1,519	$2,337	$2,219	$3,771
New Construction	$100	$425	$825	$1,478	$2,771
Incentive Amount	$200	$400	$500	$500	$1,000
Savings Per Participant	3 GJ	6.5 GJ	8.3 GJ	7.3 GJ	5 GJ
Measure Life	13 years for tanks on FEI and 10 years on FEVI, 20 years for tankless - Manufacturers, CANETA and OPA studies				
Sources of Assumptions	Manufacturers and other utilities ACEEE Emerging Hot Water Technologies and Practices for Energy Efficiency as of 2011. October 2011. Report Number A112. Canadian Residential Water Heater Market Assessment. 2009. Caneta Research Inc Residential High Efficiency Water Heater Pilots - preliminary results				
Free Rider Rate & Source	10% Weighted average based on estimates of market penetration of total water heater market from manufacturers and CANETA				

Participants

Service Region	2012 Total Projected	2012 Actual: ESTAR 0.67 EF Storage Tank – Retrofit	ESTAR 0.67 EF Storage Tank – New Construction	Non-Condensing Tankless – Retrofit	Non-Condensing Tankless – New Construction	Condensing Tankless & Hybrids – Retrofit	Condensing Tankless & Hybrids – New Construction	Condensing Storage Tank – Retrofit	Condensing Storage Tank – New Construction
FEI	1,816	0	1	6	0	79	31	0	0
FEVI	204	0	1	14	12	34	3	1	0
FEW	20	0	0	0	0	2	0	0	0
Total	2,040	0	2	20	12	115	34	1	0

Expenditures ($,000s)

Service Region	Incentives	Non- Incentives: Dealer Incentives	Admin	Communication	Research & Evaluation	Total
FEI	58	5	8	22	4	97
FEVI	30	2	1	1	1	35
FEW	1	0	0	0	0	1
Total	89	8	9	23	4	133

Notes:

- Incentives for tankless, hybrid and condensing storage tank water heater technologies were launched in July, 2012. The 0.67 EF storage tank water heater measure was launched September 1, 2012 as manufacturers first introduced these products into the BC market.
- The water heater program uptake was lower than forecasted. Water heater programs tend to take longer to gain awareness in the market (in comparison to furnace programs, for example). The new technologies represent only 7-10 percent of the total water heater market and are more expensive than standard water heaters. The original estimations in the 2012-2013 EEC Plan were based on 58 percent of the units represented by 0.67 EF tanks which were only recently introduced into the BC market (September 2012).
- Dealer Sales Promotion Incentive Fund ("SPIF") is broken out as non-incentive expenditures.

Table 5-3: EnerChoice Fireplace Program

Program Description	This program provides rebates to customers that install an energy efficient EnerChoice fireplace. To help drive program awareness and participation, the program also provides a dealer incentive. The goal is to educate consumers and dealers about the importance of selecting natural gas fireplaces based on energy efficient performance that provides zone heating rather than just decorative features.
Target Market	Residential customers
New vs Retrofit	Both
Eligible Measures	EnerChoice Fireplace
Incremental Measure Cost	$150 Hearth Manufacturers – based on the manufacturer's cost of installing energy efficient technology.
Incentive Amount	$300 + $50 SPIF*
Savings Per Participant	7.75 GJ Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates
Measure Life	15 years
Sources of Assumptions	Impact of Terasen Gas Pilot Fireplace Program (2004) by Habart and Associates Hearth Manufacturers and Hearth Patio and BarBQue Association 2010 Conservation Potential Review Data from prior program participants
Free Rider Rate & Source	24% - Findings of previous programs. In this competitive industry it is challenging to access market share data. Starting to be higher market saturation of EnerChoice models across North America however there is anecdotal evidence from industry that low cost lower efficiency base models are taking on a higher market share in the retrofit market. Free Ridership in New Construction is very low (less than 10%) based on anecdotal evidence from industry. Note: Participant feedback of 12% ensures that 24% is a conservative estimate.

Participants

	2012 Projected	2012 Actual		Retrofit	New Construction
Service Region		$150 Program	$300 Program	Total	Total
FEI	2,880	15	2,364	2,379	2
FEVI	684	1	738	739	40
FEW	36	0	8	8	0
Total	3,600	16	3,110	3,126	42

Expenditures ($,000s)

	Incentives	Non-Incentives				Total
Service Region		Dealer Incentives	Admin	Communication	Research & Evaluation	
FEI	712	118	26	59	0	914
FEVI	234	37	6	15	0	291
FEW	2	0	0	0	0	3
Total	948	155	32	74	0	1,209

Notes:

- SPIF is broken out as non-incentive expenditures.

Table 5-4: "Give your Furnace/Fireplace Some TLC" – Service Campaign

Program Description	This program educates customers about the benefits of ensuring that their natural gas appliances are operating as efficiently as possible through regular appliance maintenance. In addition, this program creates opportunities for contractors to engage in dialogue with customers about upgrading appliances to more efficient models. The 2010 Program evaluation determined that 4% of participants' heating systems had gas leaks and 15% were advised to either upgrade or replace their appliance. The 2011 Program evaluation identified 16% of participants' heating systems had gas leaks or safety issues and 11% were advised to either upgrade or replace their appliance.
Target Market	Residential customers
New vs Retrofit	Retrofit
Eligible Measures	Furnace service and fireplace service
Incremental Measure Cost	$150 was the average furnace service cost based on participant data
Incentive Amount	$25 value to participant
Savings Per Participant	Unknown
Measure Life & Source	N/A
Free Rider Rate & Source	N/A

Participants

Service Region	2012 Projected	2012 Actual	Service Type: Furnace	Service Type: Fireplace
FEI	15,575	19,027	14,356	4,671
FEVI	1,750	3,617	1,782	1,835
FEW	175	1	1	0
Total	17,500	22,645	16,139	6,506

Expenditures ($,000s)

Service Region	Incentives	Non-Incentives: Admin	Non-Incentives: Communication	Non-Incentives: Research & Evaluation	Total
FEI	428	126	35	13	602
FEVI	81	18	4	1	105
FEW	0	0	0	0	0
Total	510	144	39	14	706

Table 5-5: Energy Efficient Home Retrofit Programs – Joint Initiatives with Governments and Utilities (LiveSmartBC and other opportunities) – Government F12

Program Description	**April 1, 2011 through March 31, 2012** This program promotes energy efficiency home retrofits involving collaboration with utility partners, as well as provincial, federal and municipal governments. The major initiative is LiveSmartBC, for which economic modeling data is presented below. Other initiatives include capacity building for weatherization and initiatives with individual municipalities. Program partners share investments in administration, evaluation and communications to engage the province in energy efficient home retrofits in a cost-effective program. Due to technical issues with customer payment processing, the Ministry of Energy, Mines and Natural Gas could not provide invoices for 2011 payments. Therefore, this 2012 EEC Annual Report includes all expenditures and savings for April 2011 to March 31, 2012. Note: The NRCan EcoAction program was back in market from June 2011 through March 31, 2012. The increased federal incentives and advertising resulted in participation rates higher than forecasted.						
Target Market	Residential customers						
New vs Retrofit	Retrofit						
Eligible Measures	Air Sealing and Draft-Proofing	Attic Insulation	Basement Insulation	Wall Insulation	Crawl Space and Misc	Windows	Certified Installation
Incremental Measure Cost	$989	$1,357	$1,186	$1,398	$684	$35/ window	N/A
Incentive Amount - FBC	$279	$276	$364	$402	$176	$27	$50
Incentive Amount- LiveSmart	$22	$186	$281	$651	$305	$31	$50
Incentive Amount -NRCan	$200	$462	$645	$1,053	$481	$40	N/A
Savings Per Participant	6.4 GJ	11.7 GJ	9.4 GJ	20.8	5.9 GJ	1.2 GJ	N/A
Measure Life & Source	20 year average assumed (10-15 years for Air Sealing, 20-25 years for Insulation, and 20-25 years for Windows); Consultations with BC Hydro, Habart & Hood, 2010 Conservation Potential Review and Dunsky Energy Consulting.						
Sources of Assumptions	Habart and Hood, Hot 2000 Energy Modeling Reports 2010, 2011 2010 Conservation Potential Review Dunsky Energy Consulting, Hot 2000 Modelling 2012, 2013 Note: At time of writing BC Hydro LiveSmart BC evaluation was not complete. Results will be included in the 2014 RRA.						
Free Rider Rate & Source	20% average assumed based on past program analysis and NRCan evaluation. *Final Report: Analysis of Net-to-gross Survey Results for the ecoENERGY Retrofit for Homes Program.* Bronson Consulting Group. August, 2010						
Participants	Service Region	2011 - 2012 Projected	2011 -2012 Customers				
	FEI	6,008	8,000				
	FEVI	675	473				
	FEW	68	0				
	Total	6,750	8,473				
Expenditures ($,000s)	Service Region	Building Envelope	Certified Installation	Non-Incentive Expenditures			Total
				Admin	Communication	Research & Evaluation	
	FEI	3,374	132	38	27	50	3,621
	FEVI	239	4	4	6	3	256
	Total	3,613	136	42	33	53	3,877

Notes:

- In 2011, LiveSmart BC was reported separately in the Joint Initiatives Program Area, but is now combined with the Residential Energy Efficiency Program Area as approved in the 2012-2013 RRA Decision.
- The results in this table represent invoices received in 2012 for retrofits that occurred between April 1, 2011 and March 31, 2012. Retrofits that occurred between April 1, 2012 and December 31, 2012 are included in Table 5-6.

- Each of the measures (air sealing, insulation and windows) is comprised of a number of sub-categories. For reporting purposes, weighted averages based on the number of participants in each sub-category for each measure type are used.
- The FEU incentive was supplemented by a Ministry of Energy, Mines and Natural Gas incentive and NRCan's EcoEnergy Program, which was in market from June 2011 through March 2012. In most cases, NRCan incentives matched the total LiveSmart BC payment.
- Measure costs and energy savings were based on Hot 2000 modelling provided by Dunsky Energy Consulting. A full program evaluation has been initiated in collaboration with BC Hydro with the purpose of validating energy savings claims with billing consumption data. At the time of writing the full report was not available, but results will be incorporated into the 2014-2018 EEC Plan if available.

Table 5-6: Energy Efficient Home Retrofit Programs – Joint Initiatives with Governments and Utilities (LiveSmartBC and other opportunities) – Government F13

Program Description	**April 1, 2012 through March 31, 2013** This program promotes energy efficiency home retrofits involving collaboration with utility partners, as well as provincial, federal and municipal governments. The major initiative is LiveSmartBC, for which economic modeling data is presented below. Other initiatives include capacity building for weatherization and initiatives with individual municipalities. Program partners share investments in administration, evaluation and communications to engage the province in energy efficient home retrofits in a cost-effective program.						
Target Market	Residential customers						
New vs Retrofit	Retrofit						
Eligible Measures	Air Sealing and Draft-Proofing	Attic Insulation	Basement Insulation	Wall Insulation	Crawl Space and Miscellaneous	Windows	Certified Installation
Incremental Measure Cost	$989	$1,357	$1,186	$1,398	$684	$35/ window	N/A
Incentive Amount - FBC	$297	$268	$346	$400	$150	$27	$50
Incentive Amount - LiveSmart	$22	$172	$231	$612	$171	$28	$50
Savings Per Participant	6.4 GJ	11.7 GJ	9.4 GJ	20.8	5.9 GJ	1.2 GJ	N/A
Measure Life & Source	20 year average assumed (10-15 years for Air Sealing, 20-25 years for Insulation, and 20-25 years for Windows); Consultations with BC Hydro, Habart & Hood, 2010 Conservation Potential Review and Dunsky Energy Consulting.						
Free Rider Rate & Source	20% average assumed based on past program analysis and NRCan evaluation. *Final Report: Analysis of Net-to-gross Survey Results for the ecoENERGY Retrofit for Homes Program.* Bronson Consulting Group. August, 2010						
Sources of Assumptions	Habart and Hood, Hot 2000 Energy Modeling Reports 2010, 2011 2010 Conservation Potential Review Dunsky Energy Consulting, Hot 2000 Modeling 2012,2013 Note: At time of writing BC Hydro LiveSmart BC evaluation was not complete. Results will be included in the 2014 RRA.						
Participants	Service Region	2012 - Projected	2012 Customers				
	FEI	2,003	2390				
	FEVI	225	195				
	FEW	23	0				
	Total	2,250	2,585				
Expenditures ($,000s)				Non-Incentive Expenditures			
	Service Region	Building Envelope Incentives	Certified Installation	Admin	Communication	Research & Evaluation	Total
	FEI	936	39	0	0	0	976
	FEVI	86	2	0	0	0	88
	FEW	0	0	0	0	0	0
	Total	1,022	42	0	0	0	1,064

Notes:

- In 2011, LiveSmartBC was reported separately in the Joint Initiatives Program Area, but is now combined with the Residential Energy Efficiency Program Area as approved in the 2012- 2013 RRA Decision.
- The results in this table represent invoices received in 2012 for retrofits that occurred between April 1, 2012 and December 31, 2012. Retrofits that occurred between April 1, 2011 and March 31, 2012 are included in Table 5-5.
- The FEU incentive is supplemented by a Ministry of Energy, Mines and Natural Gas incentive.
- Measure costs and energy savings were based on Hot 2000 modelling provided by Dunsky Energy Consulting. A full program evaluation has been initiated in collaboration with BC Hydro with the purpose of validating energy savings claims with billing consumption data. At the time of submission, the full report was not available, but results will be incorporated into the 2014-2018 EEC Plan if available.
- Non-incentive expenditures were captured in the April 1, 2011 to Mar 31, 2012 iteration as presented in Table 5.5. Additional administrative expenses will be reported in 2013.

Table 5-7: ENERGY STAR® Washers and Other Measures for DHW Conservation

Program Description	This program provides rebates on qualifying high efficiency ENERGY STAR® clothes washers in collaboration with electric utility partners.
Target Market	Residential customers
New vs Retrofit	Retrofit
Eligible Measures	Select ENERGY STAR® Washing Machines
Incremental Measure Cost	$102
Incentive Amount	$50 + $25 BC Hydro or FortisBC Inc. (electric utility) for a total customer incentive of $75
Savings Per Participant	1.0 GJ natural gas plus 0.25 GJ electric - Based on 2010 Conservation Potential Review
Measure Life & Source	14 years - 2010 Conservation Potential Review and Ontario Power Authority "2010 Prescriptive Measures and Assumptions: Release 1"
Free Rider Rate & Source	20% - BCHydro, based on market share of eligible washers

Participants

Service Region	2012 Projected	2012 BCH	2012 FBC - Electric	2012 FBC - Dishwasher Pilot
FEI	3,026	10,489	635	206
FEVI	340	974	0	0
FEW	34	1	0	0
Total	3,400	11,464	635	206

Expenditures ($,000s)

Service Region	Incentives	Non-Incentive Expenditures: Admin	Non-Incentive Expenditures: Communication	Non-Incentive Expenditures: Research & Evaluation	Total
FEI	561	45	2	0	609
FEVI	48	3	0	0	51
FEW	0	0	0	0	0
Total	610	48	2	0	660

Notes:

- The ENERGY STAR Washers Program, formerly included in the Joint Initiatives Program Area was moved to the Residential Program Area as approved in the 2012-2013 RRA Decision.
- FEI conducted a small ENERGY STAR Dishwashers Pilot with FortisBC Inc. PowerSense. Because the market is transformed and incremental natural gas savings are limited, the program will not be continued in 2013. The percentage of participants is small relative to the total number

of participants in the washer program, therefore the costs were included in the washer program but no energy savings were claimed.

Table 5-8: New Construction – EnerGuide 80 and Energy Efficient Appliances (new)

Program Description	This program provides education and financial incentives to new home builders that attain EnerGuide for Homes (EG) 80 through building envelope measures. This program supports the pending efficiency updates to the BC Building Code (2013) and also educates consumers about the benefits of purchasing energy efficient new homes. The Companies are collaborating with the BC Hydro Power Smart New Homes and FortisBC PowerSense programs. Although promoted within the New Home program, water heaters and fireplaces are recorded in their respective individual programs.				
Target Market	Builders of residential properties – single family homes and townhomes				
New vs Retrofit	New Construction				
Eligible Measures	EG80 Single Family Dwellings	EG80 Townhome/Rowhome		Boilers	
Incremental Measure Cost	$8,294	$200		$1,350	
Incentive Amount	$1500 + $500 from BCHydro	$100 + $100 from BCHydro		$1,000	
Savings Per Participant	16.3 GJs	2.6 GJs		8.4 GJs	
Measure Life	25+ years	25+ years		18 years	
Sources of Assumptions	*New Construction Costs and Savings and Life Cycle Costs,* 2011, Cooper and Habart, and Dunsky Energy Consulting, Consultations with BCHydro and FortisBC PowerSense				
Free Rider Rate & Source	10% - In 2013, builder focus groups will help determine current EG 80 market share.				

Participants

Service Region	2012 Projected	2012 Actual EG80 SFD	2012 Actual EG80 Rowhome	2012 Actual Boiler
FEI	1,359	11	245	8
FEVI	279	3	0	0
FEW	0	0	0	0
Total	1,638	14	245	8

Expenditures ($,000s)

Service Region	Incentives	Non-Incentive Expenditures: Program Administration	Non-Incentive Expenditures: Communication	Non-Incentive Expenditures: Research & Evaluation	Total
FEI	167	5	20	12	205
FEVI	5	0	2	1	8
FEW	0	0	0	0	0
Total	171	6	22	13	212

Notes:

- Energy savings and participant costs were derived from the study, *New Construction Costs and Savings and Life Cycle Costs*, 2011, Cooper and Habart. Further analysis of energy savings and participant costs will be conducted in 2013.
- Row home totals include 128 units from the EG80 Quadra Pilot that was initiated in 2010. In addition to EG80, the units include tankless condensing water heaters. The additional costs and savings for these appliances were factored into the cost-effectiveness tests.

Table 5-9: Furnace Replacement Pilot Program (new)

Program Description	The Furnace Replacement Pilot Program targets customers with functioning furnaces (standard or mid-efficiency) or boilers and encourages them, through a combination of marketing and incentives, to replace the furnace now rather than waiting for the furnace to fail at some point in the future. Evidence suggests that British Columbia has the lowest installation of high efficiency furnaces out of any province in Canada, likely representing over 500,000 standard and mid-efficiency furnaces in operation. In the 2012-2013 RRA Decision, the BCUC approved expenditures of $2 Million for each of 2012 and 2013 for the Furnace Replacement Pilot Program. This pilot will help determine if an incentive program can influence homeowners to advance their furnace replacement decision. Within eight weeks of the pilot launching September 1, 2012, over 3000 participants replaced standard and mid-efficiency furnaces, indicating that there is a strong market demand for a furnace replacement incentive. At the time of writing, more in-depth evaluation is under way and the 2013 pilot program is being developed with improvements based on experience gained in the 2012 pilot. A detailed program design and funding request for 2014 and subsequent years will be submitted with the 2014-2018 RRA.
Target Market	Residential customers
New vs Retrofit	Retrofit
Eligible Measures / % of participants	Standard efficiency (80%) / Mid - Efficiency (18%) / Boilers (2%)
Incremental Measure Cost*	$1,483 / $1,483 / $4,413
Incentive Amount	$800
Savings Per Participant **	10 GJs / 5.5 GJs / 8.8 GJs
Measure Life & Source	Furnace - 18 years and Boiler - 18 years -Navigant Consulting report, BC Hydro Power Smart QA Standard,
Free Rider Rate & Source	A precise estimate of free ridership is under development. A preliminary estimate is 8% based on 8% of participants with repair costs greater than $1000 .
Sources of Assumptions	2012 Furnace Replacement Pilot Program Evaluation - Preliminary Report, by Habart and Associates.

Participants

Service Region	2012 Projected	2012 Actual	Dealer Incentive
FEI	0	2,899	2,233
FEVI	0	129	83
FEW	0	3	3
Total	2,000	3,031	2,319

Expenditures ($,000s)

Service Region	Incentives	Non-Incentives				Total
		Dealer Incentive	Admin	Communication	Research & Evaluation	
FEI	2,319	223	22	32	53	2,649
FEVI	103	8	2	7	6	127
FEW	2	0	0	0	0	3
Total	2,425	232	24	40	58	2,779

Notes:

- Two significant factors contributed to the success of the Pilot. The first was a Program Design Workshop on May 30, 2012 where experienced furnace industry representatives provided their feedback into successful program design elements. The second factor was engagement by the FEU contractor program network, which was instrumental in driving program participation.
- At the time this Report was submitted, the 2012 pilot evaluation was in progress. Inputs for savings analysis are based on the preliminary evaluation of program participants as of December 15, 2012. Further evaluation results and a comprehensive program design for 2014-2018 will be submitted with the next RRA.

Table 5-10: On-Bill Financing Pilot Program

Program Description	A loan of up to $10,000 to implement energy efficient measures. This pilot program is available to FortisBC electric-only customers or customers who receive both natural gas and electric services in the South Okanagan and who undertake energy upgrades for their homes under the guidance of a certified Energy Advisor. Loans carry a 4.5% interest rate and are amortized over 10 years. This program is operated by FortisBC electric. Any natural gas customers participating in the program are cross charged to FortisBC natural gas accordingly.				
Target Market	South Okanagan residential customers				
New vs Retrofit	Retrofit				
Eligible Measures	Primary space heating, air sealing and insulation, hot water heating, window and door replacement				
Incremental Measure Cost	To be determined by pilot				
Incentive Amount	Loan administration and reduced interest rate (4.5% vs. FEI weighted average cost of capital).				
Savings Per Participant	To be determined by pilot				
Measure Life & Source	To be determined by pilot				
Free Rider Rate & Source	To be determined by pilot				
Participants	Service Region	2012 Projected	2012 Actual		
	FEI	4	0		
	FEVI	n/a	n/a		
	FEW	n/a	n/a		
	Total	4	0		
2012 Expenditures ($,000s)	2012 Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	24	0	0	24
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	24	0	0	24

Notes:

- The Companies began implementation of the On-Bill Financing Pilot Program following the enactment of the Improvement Financing Regulation under section 17.1 of British Columbia's *Clean Energy Act*. Learning outcomes from this pilot program will be provided to the British Columbia Ministry of Energy, Mines and Natural Gas to assist it with developing any future financing programs.

5.4 2012 Residential Energy Efficiency Programs Planned But Not Launched

5.4.1 HOME ENERGY EFFICIENCY WEB PORTAL

The intention of this program is to develop a home energy efficiency web portal with content, energy saving tips and a "one-stop rebate shop" for the Province of British Columbia. Web requirements were developed in 2011, and the Companies are now determining the best time to launch this activity within the collaborative utility partner and government framework.

5.4.2 CUSTOMER ENGAGEMENT TOOL FOR CONSERVATION BEHAVIOURS

The intention of this program is to develop a communications tool that engages customers in behaviour change utilizing Home Energy Reports that track energy consumption trends. However, in 2012 the Companies made the decision to focus primarily on core programs that generate significant energy savings. The FEU are currently researching options that will provide the most benefit to customers at the least cost. In addition, the Companies will be investigating solutions that may be valuable for both electric and natural gas customers and the potential for a province-wide collaborative approach.

5.5 2012 Residential Energy Efficiency Program Closures

5.5.1 0.62 EF Efficient Water Heater Program

Due to the provincial *Energy Efficiency Act* minimum standards for water heaters, the 0.62 EF Water Heater Program has met its objectives and was officially closed on December 31, 2011. Some costs were incurred in 2012 to close off the program. These expenditures were included in non-program admin expenses in the ENERGY STAR® DHW Technologies Program Summary (Table 5-2).

5.6 Summary

Residential Energy Efficiency Program Area activity in 2012 resulted in over 200,000 GJ/year of natural gas savings. Residential Energy Efficiency programs enabled customers to upgrade appliances and capture energy savings, supporting the introduction of new provincial regulations and establishing relationships with the trades for education and program awareness. The combination of financial incentives, policy support, contractor outreach and effective marketing is instrumental to the ongoing success of these programs in generating natural gas savings and fostering market transformation in the residential sector.

Universality is a key guiding principle for the Companies' EEC initiatives. Amendments to the Demand-Side Measures Regulations have enabled more programs to be developed, resulting in significant energy savings benefits for residential customers. The Province, in turn, benefits from the resulting GHG emissions reductions in the residential building sector.

6 LOW INCOME ENERGY EFFICIENCY PROGRAM AREA

6.1 Overview

The Low Income Program Area made significant progress in 2012. The Companies saw continued success with the Energy Savings Kit ("ESK") Program, implemented two inspiring Residential Energy Efficiency Works ("REnEW") sessions and in June launched the long anticipated Energy Conservation Assistance Program ("ECAP"). All three of these programs are partnerships with BC Hydro. The FortisBC Inc. electric utility is already a partner in the REnEW program and will be fully integrated in to the ESK and ECAP partnerships in 2013 as well.

In addition to the Companies' own Low Income programs, progress continues to be made on investing the $5.2 million in funds granted to the Companies by the Ministry of Energy, Mines and Natural Gas. In 2012, the Companies invested $320,408, primarily in retrofits in low income buildings.

Table 6-1 summarizes the projected and actual expenditures for the Low Income Program Area in 2012, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results. The cost-effectiveness test for low income EEC programs uses a value of 130% of the benefits in accordance with Section 4(2)(b) of the Demand-Side Measures Regulation.

Table 6-1: 2012 Low Income Program Results Summary

Program and Service Territory	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
FEI	No Direct Savings			0	0	0	11	0	11	No Direct Savings				
FEVI				0	0	0	0	0	0					
Total				0	0	0	11	0	11					
Residential Energy Efficiency Works (REnEW)														
FEI	No Direct Savings			0	0	145	91	145	91	No Direct Savings				
FEVI				0	0	40	0	40	0					
Total				0	0	185	91	185	91					
Energy Saving Kit (ESK)														
FEI	14,164	11,971	69,628	165	120	135	86	300	207	4.6	n/a	3.8	n/a	0.6
FEVI	1,574	4,627	27,415	18	36	6	17	34	53	7.1	n/a	5.8	n/a	0.5
Total	15,738	16,598	97,043	183	156	151	103	334	260					
Energy Conservation Assistance Program (ECAP)														
FEI	13,005	461	3,309	2,588	75	1,418	142	4,005	217	0.2	n/a	0.2	n/a	0.2
FEVI	1,445	53	387	288	9	158	15	445	24	0.2	n/a	0.2	n/a	0.2
Total	14,450	514	3,696	2,875	84	1,575	157	4,450	241					
ALL PROGRAMS														
FEI	**27,169**	**12,432**	**72,937**	**2,753**	**195**	**1,698**	**330**	**4,450**	**525**	**1.7**	**n/a**	**1.6**	**n/a**	**0.5**
FEVI	**3,019**	**4,680**	**27,802**	**306**	**45**	**204**	**33**	**519**	**78**	**4.6**	**n/a**	**4.0**	**n/a**	**0.5**
Total	**30,188**	**17,112**	**100,739**	**3,058**	**240**	**1,911**	**363**	**4,969**	**603**	**2.1**	**n/a**	**1.9**	**n/a**	**0.5**

6.2 2012 Low Income Programs

Tables 6-2 through 6-4 outline the specific Low Income programs undertaken in 2012, including program and measure descriptions and a breakdown of non-incentive spending.

Table 6-2: Residential Energy Efficiency Works (REnEW) Program

Program Description	This program provides energy efficiency trade training by industry experts at no cost to participants. The participants are selected by the delivery agents in the community and this program is specifically targeted to marginalized populations and people facing employment barriers. The training program is based on materials developed by the Companies and is focused on the Energy Efficiency trade industry. The program also includes First Aid, Workplace Hazardous Materials Information System ("WHMIS"), Construction Safety Training Systems ("CSTS"), Fall Protection, and other trade industry certifications, a set of tools and a tool belt, and two meals per day during training. This training program is offered in partnership with BC Hydro and FortisBC Inc. (electric utility).				
Target Market	Low income individuals facing barriers to employment				
New vs Retrofit	Retrofit				
Eligible Measures	N/A				
Incremental Measure Cost	N/A				
Incentive Amount	N/A				
Savings Per Participant	N/A				
Measure Life & Source	N/A				
Free Rider Rate & Source	N/A				
Participants	Service Region	2012 Projected	2012 Actual		
	FEI	43	22		
	FEVI	12	0		
	FEW	0	0		
	Total	55	22		
Expenditures ($,000s)	2012				
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	85	4	2	91
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	85	4	2	91
Expenditures ($)	2012				
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	84,710	4,320	1,650	90,680
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	84,710	4,320	1,650	90,680

Table 6-3: Energy Saving Kit (ESK) Program

Program Description	This program provides a bundle of easy-to-install energy efficiency measures for low-income households, and is offered in partnership with BC Hydro. FortisBC Inc. (electric utility) currently services their customers through an ESK program of their own and in 2013 FEU will begin a partnership in the shared services territory.
Target Market	Low Income Residential Customers
New vs Retrofit	Retrofit
Eligible Measures	Faucet aerators, Low Flow Showerhead, Water Heater Pipe Wrap, Caulking, Draft proofing, Outlet Gaskets, Window Film
Incremental Measure Cost	$13.51 - Average based on the full cost of the gas measures included in the ESK and pro-rated by the proportion of participants that use natural gas for space or water heating.
Incentive Amount	$13.51 - Since the program is free to participants, the incentive equals the incremental cost
Savings Per Participant	2 GJ - Updated savings to align with 2011 CPR results.
Measure Life & Source	8 years - Average based on the individual gas measures included in the Energy Saving Kit
Free Rider Rate & Source	27% - Based on participant survey

Participants

Service Region	2012 Projected	2012 Actual
FEI	16,287	8,413
FEVI	1,830	3,169
FEW	183	0
Total	18,300	11,582

Expenditures ($,000s)

2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	120	51	35	0	207
FEVI	36	13	5	0	53
FEW	0	0	0	0	0
Total	156	64	39	0	260

Table 6-4: Energy Conservation Assistance Program (ECAP)

Program Description	This is a full-service direct-install program that provides opportunities for deep energy savings in low-income households. Offered in partnership with BC Hydro, the program targets low-income homes with moderate to high gas consumption and installs a customized assortment of energy saving measures. The program also installs measures that improve the health and safety of participants, such as improving ventilation and installing carbon monoxide detectors.
Target Market	Low Income Residential Customers
New vs Retrofit	Retrofit
Eligible Measures	Basic Stream of measures includes direct Installation of: Faucet aerators, Low Flow Showerheads, Water Heater Pipe Wrap, Caulking, Draftproofing, Outlet Gaskets, Window Film, and Basic Draftproofing. Advanced Stream of measures includes all the above and, in some cases: Ceiling/Wall/Crawl Insulation, Advanced Draftproofing, Carbon Monoxide Detectors and Ventilation.
Incremental Measure Cost	$438 - Average based on the full cost of the gas measures installed in gas heated homes
Incentive Amount	$438 - Since the program is free to participants, the incentive equals the incremental cost
Savings Per Participant	3 GJ
Measure Life & Source	13 years - Average based on the individual gas measures included in ECAP
Free Rider Rate & Source	4% - Primarily third-party studies

Participants

Service Region	2012 Projected	2012 Actual
FEI	2,225	172
FEVI	250	19
FEW	25	0
Total	2,500	191

Expenditures ($,000s) — 2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	75	81	52	9	217
FEVI	9	9	5	1	24
FEW	0	0	0	0	0
Total	84	90	57	10	241

Expenditures ($) — 2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	74,649	80,666	52,039	9,322	216,676
FEVI	8,962	9,140	5,201	1,036	24,338
FEW	0	0	0	0	0
Total	83,611	89,806	57,239	10,358	241,014

Notes:

- The TRC for the ECAP is lower for 2012 than the Companies expect it to be in future years. In 2012 the program was under development for the first five months of the year and, once launched, it took several months of outreach to engage this hard-to-reach customer segment. Further, the engagement period with the program is sometimes several months (i.e. participants apply for the program, and then sometimes receive multiple visits by contractors to install various energy savings measures). The Companies do not count the participants until all measures have been installed. Because of these reasons, there were only 191 participants included in the 2012 program results. The Companies expect growth in participation in the program in 2013, and have already attracted over 100 participants in the first two months of 2013. This will improve the TRC moving forward.

6.3 Summary

The Low Income Program Area has been an important priority for the Companies since the initial creation of the EEC Program Principles. The goal of creating programs that are accessible to all has already been achieved through the launch of the ESK Program, the REnEW Program and the new ECAP launched in June of 2012. Continued increase in investment and a deeper level of savings for our low income customers is expected for 2013.

7 COMMERCIAL ENERGY EFFICIENCY PROGRAM AREA

7.1 Overview

In 2012, Commercial Energy Efficiency programs continued to successfully encourage commercial customers to reduce their overall consumption of natural gas and their associated energy costs. The Commercial Energy Efficiency Program Area was successful in reducing annual natural gas consumption by over 160,000 GJS and achieving an overall TRC of 1.2, despite incurring some significant program development costs required to launch new programs. Nearly $5 Million was invested in Commercial Energy Efficiency, approximately 87% of which was incentive spending.

Table 7-1 summarizes the projected and actual expenditures for the Commercial Energy Efficiency Program Area in 2012, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results.

Table 7-1: 2012 Commercial Energy Efficiency Program Results Summary

Program and Service Territory	Annual Gas Savings (GJ/yr.) 2012-2013 EEC Plan	Annual Gas Savings (GJ/yr.) 2012 Actual	Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s) Incentives 2012-2013 EEC Plan	Incentives 2012 Actual	Non-Incentives 2012-2013 EEC Plan	Non-Incentives 2012 Actual	All Spending 2012-2013 EEC Plan	All Spending 2012 Actual	Benefit/Cost Ratios TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
FEI	No Direct Savings			0	0	0	157	0	157	No Direct Savings				
FEVI				0	0	0	4	0	4					
Total				0	0	0	161	0	161					
Efficient Boiler Program														
New Construction														
FEI	26,725	2,683	26,759	620	67	19	4	638	71	2.3	n/a	3.7	4.3	0.6
FEVI	3,207	317	3,310	69	28	2	1	71	29	1.0	n/a	1.1	2.5	0.4
Retrofit														
FEI	72,420	43,001	428,868	1,924	1,176	105	101	2,030	1,277	2.9	n/a	3.3	5.6	0.5
FEVI	8,160	12,475	130,127	214	402	12	11	226	413	2.7	n/a	3.1	4.9	0.6
Total	110,512	58,476	589,064	2,827	1,673	138	117	2,965	1,790					
Light Commercial Boiler Program														
New Construction														
FEI	888	180	1,799	9	3	3	0	14	3	2.2	n/a	6.1	3.7	0.6
FEVI	0	0	0	1	0	0	0	3	0	n/a	n/a	n/a	n/a	n/a
Retrofit														
FEI	7,400	433	4,318	86	6	28	1	115	7	1.1	n/a	6.0	1.9	0.6
FEVI	1,184	19	197	10	1	3	0	14	1	0.4	n/a	2.5	0.8	0.5
Total	9,472	632	6,314	106	10	34	1	146	11					
Efficient Commercial Water Heater Program														
New Construction														
FEI	800	2,265	22,588	17	56	2	8	20	64	1.1	n/a	2.5	2.5	0.4
FEVI	89	308	3,211	3	2	0	1	4	3	4.9	n/a	6.8	12.2	0.5
Retrofit														
FEI	6,230	6,092	60,762	156	93	23	28	178	121	0.9	n/a	3.6	2.1	0.5
FEVI	1,068	585	6,104	27	13	4	3	31	15	1.1	n/a	2.8	2.5	0.5
Total	8,188	9,250	92,665	203	163	29	40	233	204					
Commercial Energy Assessment Program														
FEI	55,632	77,080	77,080	143	412	45	21	188	432	1.7	n/a	1.1	n/a	0.3
FEVI	18,544	10,785	10,785	48	59	15	5	63	64	1.6	n/a	1.1	n/a	0.3
Total	74,176	87,865	87,865	191	471	60	26	250	497					
Spray Valve Program														
New Construction														
FEI	28	0	0	0	0	0	0	0	0	n/a	n/a	n/a	n/a	n/a
FEVI	0	0	0	0	0	0	0	0	0	n/a	n/a	n/a	n/a	n/a
Retrofit														
FEI	2,933	1,259	5,056	42	9	2	11	44	20	2.2	n/a	2.1	n/a	0.5
FEVI	333	230	937	5	2	0	2	5	4	2.2	n/a	2.1	n/a	0.5
Total	3,294	1,489	5,993	47	11	2	13	51	23					
Commercial Custom Design Program														
New Construction														
FEI	5,058	0	0	400	13	17	5	492	19	n/a	n/a	n/a	n/a	n/a
FEVI	1,264	0	0	100	0	2	1	152	1	n/a	n/a	n/a	n/a	n/a
Retrofit														
FEI	43,928	0	0	1,318	34	86	8	1,507	41	n/a	n/a	n/a	n/a	n/a
FEVI	11,560	0	0	330	11	21	3	401	14	n/a	n/a	n/a	n/a	n/a
Total	61,810	0	0	2,148	58	126	17	2,553	74					
Continuous Optimization Program														
FEI	41,454	2,462	9,886	704	739	86	1	790	740	0.1	n/a	0.1	1.1	0.1
FEVI	1,692	620	2,529	29	159	6	0	34	159	0.1	n/a	0.1	1.1	0.1
Total	43,146	3,082	12,415	733	898	92	1	825	899					
Efficiency à la Carte (Commercial Kitchen Program)														
New Construction														
FEI	56	149	1,134	2	5	0	48	2	53	0.2	n/a	0.2	2.9	0.1
FEVI	0	139	1,094	0	5	0	7	0	12	0.7	n/a	0.8	3.1	0.4
Retrofit														
FEI	506	0	0	22	0	3	0	24	0	n/a	n/a	n/a	n/a	n/a
FEVI	56	448	3,521	2	10	0	4	2	13	2.2	n/a	2.5	5.5	0.5
Total	618	736	5,749	26	19	4	60	28	79					
MURB Program														
New Construction														
FEI	1,620	0	0	30	0	2	0	32	0	n/a	n/a	n/a	n/a	n/a
FEVI	360	0	0	8	0	0	0	8	0	n/a	n/a	n/a	n/a	n/a
Retrofit														
FEI	6,300	130	878	119	4	9	0	128	4	2.2	n/a	2.0	n/a	0.5
FEVI	1,620	0	0	30	0	2	0	32	0	n/a	n/a	n/a	n/a	n/a
Total	9,900	130	878	186	4	14	0	200	4					

Table 7-1: 2012 Commercial Energy Efficiency Program Results Summary (Continued)

Program and Service Territory	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Fireplace Timers Pilot Program														
FEI		No Direct Savings		0	0	68	9	68	9			No Direct Savings		
FEVI				0	0	8	1	8	1					
Total				0	0	76	10	75	10					
Radiant Tube Heaters Pilot Program														
FEI	748	0	0	12	0	8	1	20	1	n/a	n/a	n/a	n/a	n/a
FEVI	0	0	0	0	0	0	0	0	0	n/a	n/a	n/a	n/a	n/a
Total	748	0	0	12	0	8	1	20	1					
EnerTracker Program														
FEI		No Direct Savings		0	0	0	122	0	122			No Direct Savings		
FEVI				0	0	0	0	0	0					
Total				0	0	0	122	0	122					
Energy Specialist Program														
FEI	0	1,081	4,713	840	729	195	71	1,035	800			n/a		
FEVI	0	0	0	120	180	22	8	142	188					
Total	0	1,081	4,713	960	909	217	79	1,177	989					
PSECA Program														
FEI		No Direct Savings		0	0	0	2	0	2			No Direct Savings		
FEVI				0	0	0	0	0	0					
Total				0	0	0	2	0	2					
ALL PROGRAMS														
FEI	**272,726**	**136,815**	**643,841**	**6,444**	**3,346**	**702**	**599**	**7,326**	**3,945**	**1.3**	**n/a**	**1.5**	**3.3**	**0.4**
FEVI	**49,138**	**25,926**	**161,815**	**995**	**869**	**98**	**51**	**1,197**	**920**	**1.5**	**n/a**	**1.7**	**3.3**	**0.5**
Total	**321,863**	**162,741**	**805,656**	**7,439**	**4,215**	**800**	**650**	**8,523**	**4,865**	**1.3**	**n/a**	**1.5**	**3.3**	**0.4**

Notes:

- In 2012 the Commercial Energy Efficiency Program Area incurred expenditures of $1,793.87 under the Public Sector Energy Conservation Agreement ("PSECA") Program. These expenditures were related to performing post-completion site audits of the participants' projects as per the program's terms and conditions.

7.2 2012 Commercial Energy Efficiency Programs

The following tables outline the specific Commercial Energy Efficiency programs undertaken in 2012, including program and measure descriptions and a breakdown of non-incentive spending.

Table 7-2: Efficient Boiler Program

Program Description	This program provides rebates for the installation of high efficiency boilers in commercial applications. Note that the program was relaunched in May of 2012 and now provides incentives for boilers previously incented under the Light Commercial Boiler Program.
Target Market	Commercial
New vs Retrofit	Both
Eligible Measures	Boilers sized 300 MBH and higher: Mid-efficiency boilers 85% ≤ T.E. ≤ 90% and condensing boilers 90% ≤ T.E. Boilers sized up to 299 MBH: Must be ENERGY STAR rated (mid-efficiency boilers 85% ≤ AFUE ≤ 90% and condensing boilers 90% ≤ AFUE). Note: T.E = Thermal Efficiency, AFUE = Annual Fuel Utilitization Efficiency.

	FEI		FEVI	
	Retrofit	New Construction	Retrofit	New Construction
Incremental Measure Cost	$18,107	$33,452	$17,164	$12,317
Incentive Amount	$12,786	$16,694	$12,175	$9,218
Savings Per Participant	570 GJ	818 GJ	461 GJ	129 GJ
Measure Life & Source	20 years - ASHRAE Handbook and Conservation Potential Review			
Free Rider Rate & Source	18% - From Efficient Boiler Program Impact Evaluation, June 12, 2003			

Participants	Service Regior	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit
	FEI	25	141	4	92
	FEVI	3	16	3	33
	FEW	0	1	0	0
	Total	28	158	7	125

Expenditures ($,000s) New Construction	2012					
	Service Regior	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	67	1	1	2	71
	FEVI	28	0	0	1	29
	FEW	0	0	0	0	0
	Total	94	1	1	3	100

Expenditures ($,000s) Retrofit	2012					
	Service Regior	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	1,176	21	24	55	1,277
	FEVI	402	0	3	8	413
	FEW	0	0	0	0	0
	Total	1,578	22	27	63	1,690

Notes:

- The Efficient Boiler Program re-launch was designed to simplify the program, reducing the burden on both program participants and the Companies, while also bringing transparency to the rebate amounts. The following improvements were made to the program with the re-launch:
  - eliminated the pre-approval process and made right sizing an optional bonus incentive;
  - reduced the number of required supporting documents by eliminating uneccessary data collection;
  - posted the rebate amounts per boiler on FortisBC.com; and
  - harmonized the boiler incentives across all boiler sizes, including between larger boiler and smaller boilers previously incented under the Light Commercial Boiler Program

Table 7-3: Light Commercial Boiler Program

Program Description	This program provided, until May of 2012, rebates for the installation of high efficiency (AFUE > 85%) commercial boilers with less than 300 MBH input. After May of 2012, rebates for boilers less than 300 MBH input were provided via the revised Efficient Boiler Program. NOTE: AFUE = Annual Fuel Utilization Efficiency, 1 MBH = 1,000 British Thermal Units per hour					
Target Market	Commercial customers					
New vs Retrofit	Both					
Eligible Measures	Near condensing boilers 85% ≤ AFUE ≤ 90% and condensing boilers AFUE ≥ 90% with input < 300 MBH.					
	FEI		FEVI			
	Retrofit	New Construction	Retrofit	New Construction		
Incremental Measure Cost	$6,101	$6,225	$5,133	$0		
Incentive Amount	$1,067	$1,338	$630	$0		
Savings Per Participant	88 GJ	110 GJ	23 GJ	0 GJ		
Measure Life & Source	20 years - ASHRAE Handbook and Conservation Potential Review					
Free Rider Rate & Source	18% - Estimated from Efficient Boiler Program					
Participants	Service Region	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit	
	FEI	3	25	2	6	
	FEVI	0	3	0	1	
	FEW	0	0	0	0	
	Total	3	28	2	7	
Expenditures ($,000s) New Construction	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	3	0	0	0	3
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	3	0	0	0	3
Expenditures ($,000s) Retrofit	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	6	0	1	0	7
	FEVI	1	0	0	0	1
	FEW	0	0	0	0	0
	Total	7	0	1	0	8

Notes:

- This program was closed in May of 2012. Refer to Section 7.2 for additional information.

Table 7-4: Efficient Commercial Water Heater Program

Program Description	This program provides rebates for the installation of high efficiency commercial water heaters with thermal efficiency greater than or equal to 84%.				
Target Market	Commercial customers				
New vs Retrofit	Both				
Eligible Measures	Near condensing storage and volume type water heaters 84% ≤ T.E. ≥ 90%; Condensing storage and volume type water heaters 90% ≤ T.E.; Condensing on demand water heaters 90% ≤ T.E. Note: T.E.= Thermal Efficiency				
	FEI		FEVI		
	Retrofit	New Construction	Retrofit	New Construction	
Incremental Measure Cost	$8,460	$9,232	$5,319	$1,216	
Incentive Amount	$1,748	$3,496	$1,788	$710	
Savings Per Participant	121 GJ	149 GJ	88 GJ	38 GJ	
Measure Life & Source	12 years - Conservation Potential Review, Consortium for Energy Efficiency data, Other Utility progran				
Free Rider Rate & Source	5% - Ontario Energy Board Approved DSM assumptions				

Participants					
	Service Region	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit
	FEI	8	70	16	53
	FEVI	1	12	3	7
	FEW	0	1	0	0
	Total	9	83	19	60

Expenditures ($,000s) New Construction	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	56	0	7	2	64
	FEVI	2	0	1	0	3
	FEW	0	0	0	0	0
	Total	58	0	8	2	68

Expenditures ($,000s) Retrofit	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	93	1	22	6	121
	FEVI	13	0	2	0	15
	FEW	0	0	0	0	0
	Total	105	1	24	6	136

Table 7-5: Commercial Energy Assessment Program

Program Description	This program identifies inefficiencies at the participant's facilities via an onsite walkthrough assessment by an energy efficiency consultant. The consultant then produces a report describing the observed inefficiencies, outlining proposed solutions and identifying any applicable incentive programs. The Companies then forward the report to the participant.					
Target Market	Commercial customers with an average annual consumption of 2,000 GJ or greater.					
New vs Retrofit	Retrofit					
Eligible Measures	Walkthrough energy assessment and written report					
	FEI	FEVI				
Incremental Measure Cost	$1,694	$1,747				
Incentive Amount	$1,694	$1,747				
Savings Per Participant	488 GJ					
Measure Life & Source	1 year – Conservative estimate					
Free Rider Rate & Source	35% - 2010 Friuch Energy Assessment Evaluation					
Participants	Service Region	2012 Projected	2012 Actual			
	FEI	112	234			
	FEVI	38	34			
	FEW	2	9			
	Total	152	277			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	396	17	3	0	417
	FEVI	59	5	0	0	64
	FEW	15	0	0	0	15
	Total	471	22	4	0	497

Table 7-6: Spray Valve Program

Program Description	This program offers the direct installation of low flow pre-rinse spray valves at no charge to the participant in order to reduce the natural gas consumption of commercial food service customers.					
Target Market	Commercial customers					
New vs Retrofit	Both					
Eligible Measures	Low flow pre-rinse spray valves					
Incremental Measure Cost	FEI: $55.95 FEVI: $55.95					
Incentive Amount	FEI: $55.95 FEVI: $55.95					
Savings Per Participant	9 GJ					
Measure Life & Source	5 years - Food Service Technology Center and Ontario Energy Board approved DSM assumptions					
Free Rider Rate & Source	12 % - Food Service Technology Center and Ontario Energy Board approved DSM assumptions					
Participants	Service Region	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit	
	FEI	3	322	0	159	
	FEVI	0	36	0	29	
	FEW	0	4	0	0	
	Total	3	362	0	188	
Expenditures ($,000s) New Construction	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	0	0
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	0	0	0	0
Expenditures ($,000s) Retrofit	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	9	11	0	0	20
	FEVI	2	2	0	0	4
	FEW	0	0	0	0	0
	Total	11	13	0	0	23

Table 7-7: Commercial Custom Design Program (new)

Program Description	This program provides eligible customers with funding towards the completion of a detailed Energy Study, to identify energy saving opportunities specific and customized to their facilties, and subsequent capital incentive funding to encourage the implementation of any cost effective measures identified therein. The program seeks to capture energy savings associated with measures that are otherwise difficult to incent as part of a prescriptive program because they are complex, and one project may include multiple measures with interactive effects. The expected energy savings, measures, capital cost, incentives etc, will neccessarily vary depending on the customer, though each project is submitted to a TRC test and must be approved by the utility.
Target Market	Commercial customers
New vs Retrofit	Both
Eligible Measures	Utility funded energy study, and utility incented Energy Saving Measures as identified in the energy study and approved by the utility. Energy Saving Measures are variable.
Incremental Measure Cost	Variable. Dependent upon participant's proposed Energy Saving Measures.
Incentive Amount	If TRC ≥ 1.0 then $5 / discounted GJ saved over 50% of the Energy Measure Life (EML), up to 10 yrs.
Savings Per Participant	Dependent upon participant's proposed Energy Saving Measures.
Measure Life & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.
Free Rider Rate & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.

Participants

Service Region	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit
FEI	4	19	1	2
FEVI	1	5	0	1
FEW	0	0	0	0
Total	5	24	1	3

Expenditures ($,000s) New Construction — 2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	13	1	5	0	19
FEVI	0	0	1	0	1
FEW	0	0	0	0	0
Total	13	1	5	0	19

Expenditures ($,000s) Retrofit — 2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	34	7	1	0	41
FEVI	11	3	0	0	14
FEW	0	0	0	0	0
Total	44	10	1	0	55

Notes:

- The Commercial Custom Design Program is complex in nature and has variable measure savings, costs, incentives and/or cash flows which, unlike in prescriptive programs, occur over a period of years. Consequently, providing results for this program within an annual report format has some limitations. In general, the savings in these types of programs occur in later years while some program costs are incurred at the outset. As a result, despite having paid out incentives and incurred some costs, there are no savings attributable to the program in 2012, as may be seen in the table above.
- *New Construction Program*:
  - Participation in this program can last for approximately five years. This is broken down into approximately 12 months to prepare the required whole building energy simulation, followed by up to 48 months to build the proposed building. The program incurs incentive expenditures upon the successful completion of the energy simulation, as well as upon

completion of the building, while natural gas savings are only obtained upon completion of the proposed building.

- This program is operated in partnership with BC Hydro Power Smart, with Power Smart acting as the lead utility guiding participants and their chosen consultants through the requisite Energy Study. By year end, one completed and reviewed Energy Study was received from BC Hydro. Note, however, that there are 10 additional energy studies which are currently in development, and another three seeking approval of their project proposals. These will be recorded as program participants when the Energy Studies are completed, approved and received from BC Hydro, at which point a portion of the incentive funding becomes payable.

- *Retrofit Program*:
  - This program remains in 'Beta' testing designed to identify and correct any significant faults before the program goes live to the market. The three participants noted in the table above represent three out of the original five Beta test applicants who successfully completed their energy studies in 2012. All three intend to proceed with the implementation of Energy Saving Measures. This program is expected to be completed and launched in 2013.

Table 7-8: Continuous Optimization Program (new)

Program Description	The Continuous Optimization Program (C.Op.), in partnership with BC Hydro Power Smart, is designed to help commercial building owners identify and correct energy wasting operational faults and continuously monitor building performance to help maintain and improve energy efficiency, resulting in reduced operating costs. The program funds re-commissioning services to study the participant's building and recommend energy efficiency improvements, as well as access to an energy management information system (EMIS) to assist in tracking the building's performance after the re-commissioning work is complete. In return, participants must implement, at their cost, measures identified by the re-commissioning study that when combined have a payback period of two years or less.
Target Market	Commercial customers with buildings >50,000 sqft who consume an average of 7,500 GJ of natural gas per year or natural gas is 40% of their building's total energy consumption.
New vs Retrofit	Retrofit
Eligible Measures	Re/Retro commissioning study, employee training, and "near time" energy consumption monitoring.
Incremental Measure Cost	Average nominal program duration incremental cost (7 years): $41,485 2012 observed average incremental cost: $5,809.93
Incentive Amount	Average nominal program duration incentive amount (7 years): $18,913 2012 observed average incentive amount: $5,477.59
Savings Per Participant	Average expected annual natural gas savings: 1,074 GJ/year 2012 observed natural gas savings: 20.74 GJ/year
Measure Life & Source	5 years - the duration of utility support for the energy management information system, plus one year.
Free Rider Rate & Source	0% - BC Hydro

Participants

Service Region	2012 Projected	2012 Actual
FEI	145	131
FEVI	6	29
FEW	2	4
Total	153	164

Expenditures ($,000s)

2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	718	1	0	0	718
FEVI	159	0	0	0	159
FEW	22	0	0	0	22
Total	898	1	0	0	899

Notes:

- The Continuous Optimization program is complex in nature and has variable measure savings, costs, incentives and/or cash flows which, unlike in prescriptive programs, occur over a period of years. Consequently, providing results for this program within an annual report format has some limitations. In general, the savings in these types of programs occur in later years while some program costs are incurred at the outset. As a result, the cost-effectiveness results shown in table 7-1 are necessarily low in these initial program years.

Table 7-9: Efficiency à la Carte (Commercial Kitchen Program (new)

Program Description	This program, launched in September of 2012, offers a suite of rebates for the installation of high efficiency commercial cooking appliances.				
Target Market	Commercial customers				
New vs Retrofit	Both				
Eligible Measures	High efficiency deep fryers, griddles, ovens (rack, combination, convection and conveyor), and steam cookers whose performance in terms of energy consumption meets or exceeds the standards outlined in the applicable ASTM Standard (per appliance).				
	FEI		FEVI		
	Retrofit	New Construction	Retrofit	New Construction	
Incremental Measure Cost	$0	$9,460	$13,745	$4,160	
Incentive Amount	$0	$5,000	$9,500	$2,250	
Savings Per Participant	0 GJ	186 GJ	560 GJ	87 GJ	
Measure Life & Source	12 years - The Food Service Technology Center and OEB DSM Assumptions				
Free Rider Rate & Source	20% - OEB DSM Assumptions				

Participants	Service Region	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit
	FEI	4	36	1	0
	FEVI	0	4	2	1
	FEW	0	0	0	0
	Total	4	40	3	1

Expenditures ($,000s) New Construction	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	5	0	48	0	53
	FEVI	5	0	7	0	12
	FEW	0	0	0	0	0
	Total	10	0	55	0	65

Expenditures ($,000s) Retrofit	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	0	0
	FEVI	10	0	4	0	13
	FEW	0	0	0	0	0
	Total	10	0	4	0	13

Table 7-10: MURB Program (new)

Program Description	This program focuses primarily on "In-Suite" gas saving measures for multi-unit residential buildings (MURBs). In 2012, energy saving measures were limited to the direct installation of low flow shower heads on a limited scale via a partnership with the City of Vancouver.					
Target Market	Commercial customers					
New vs Retrofit	Both					
Eligible Measures	Low flow showerheads					
Incremental Measure Cost	$33.19 per showerhead					
Incentive Amount	$33.19 per showerhead					
Savings Per Participant	1.2 GJ/yr per showerhead					
Measure Life & Source	5 years - OEB approved DSM assumptions and Conservation Potential Review					
Free Rider Rate & Source	10% - OEB approved DSM assumptions					
Participants	Service Region	2012 Projected - New Construction	2012 Projected - Retrofit	2012 Actual - New Construction	2012 Actual - Retrofit	
	FEI	9	35	0	120	
	FEVI	2	9	0	0	
	FEW	0	0	0	0	
	Total	11	44	0	120	
Expenditures ($,000s) New Construction	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	0	0
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	0	0	0	0
Expenditures ($,000s) Retrofit	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	4	0	0	0	4
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	4	0	0	0	4

Notes:

- The forecasted participants in the 2012-2013 EEC Plan represented estimated participating buildings. Conversely, the number presented here represents the number of showerheads installed.
- Program activities in 2012 consisted of a pilot direct install program in partnership with the City of Vancouver. In this initial foray, 120 low flow showerheads were installed in 12 buildings.

Table 7-11: Fireplace Timers Pilot Program

Program Description	This pilot program assesses the natural gas savings potential of fireplace "time-of-operation" controllers in multi-unit residential buildings.					
Target Market	Commercial customers					
New vs Retrofit	Both					
Eligible Measures	Electronic fireplace "time-of-operation" controller					
Incremental Measure Cost	$50					
Incentive Amount	$50					
Savings Per Participant	3 GJ					
Measure Life & Source	5 years - Assumed value. No similar equipment is known to exist.					
Free Rider Rate & Source	0% - Pilot Program assumption.					
Participants	Service Region	2012 Projected	2012 Actual			
	FEI	0	0			
	FEVI	0	0			
	FEW	0	0			
	Total	0	0			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	9	9
	FEVI	0	0	0	1	1
	FEW	0	0	0	0	0
	Total	0	0	0	10	10

Notes:

- There were no participants in 2012, as the pilot was closed to new participants. Expenditures are entirely associated with impact evaluation efforts. Refer to the Evaluation section of this Report (Section 13) for additional details.

Table 7-12: Radiant Tube Heaters Pilot Program

Program Description	This pilot program assesses the incremental costs and savings potential of radiant tube heaters when used for space heating in place of standard unit heaters.					
Target Market	Commercial customers					
New vs Retrofit	Both					
Eligible Measures	Radiant tube heaters					
Incremental Measure Cost	Variable. Dependent upon individual participant's facility / building.					
Incentive Amount	If TRC ≥ 1.0 then up to 75% of incremental cost between radiant tube heaters and standard unit heaters.					
Savings Per Participant	Variable. Dependent upon individual participant's facility / building.					
Measure Life & Source	20 years - OEB approved DSM assumptions					
Free Rider Rate & Source	0% - Pilot Program assumption					
Participants	Service Region	2012 Projected	2012 Actual			
	FEI	13	0			
	FEVI	0	0			
	FEW	0	0			
	Total	13	0			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	1	1
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	0	0	1	1

Notes:

- Expenditures are for the removal of sub-metering equipment. Refer to the Evaluation section of the report (Section 13) for additional details.
- Henceforth, the Innovative Technologies group will be continuing investigation on radiant tube heater technology as part of the Condensing Unit Heater Pilot. Refer to the Innovative Technologies section (Section 9) for additional details.

Table 7-13: EnerTracker Program

Program Description	This three year pilot program provides customers with access to an energy management information system (EMIS). EMIS software provides customers with a detailed picture of their natural gas consumption in "near time." Timely access to this information is expected to speed up fault detection, thereby enabling more rapid corrective action to avoid wasted gas consumption, as well as assisting in the identification of additional potential natural gas conservation measures.				
Target Market	Commercial customers with existing AMR device.				
New vs Retrofit	Retrofit				
Eligible Measures	Energy management information system				
Incremental Measure Cost	$720.50 / yr (Average)				
Incentive Amount	$720.50 / yr (Average)				
Savings Per Participant	2% of annual natural gas consumption				
Measure Life & Source	1 year – Measure life is based on annual EMIS software subscription				
Free Rider Rate & Source	6.4% - Proof of concept study				
Participants	Service Region	2012 Projected	2012 Actual		
	FEI	0	0		
	FEVI	0	0		
	FEW	0	0		
	Total	0	0		
Expenditures ($,000s)	2012				
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	122	1	0	122
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	122	1	0	122

Notes:

- This program was formally rolled out to customers on January 7, 2013. 2012 expenditures represent development costs incurred prior to program launch.
- As there is currently insufficient Automated Meter Reader ("AMR") infrastructure in the FEVI service territory to support the roll out of this pilot, program availability is limited to the FEI service territory.

Table 7-14: Energy Specialist Program

Program Description	This program funds Energy Specialist positions, whose key priority is to identify opportunities for their organization to participate in FortisBC's EEC programs. The Energy Specialist reports to the Customer's BC Hydro funded Energy Manager on holistic energy reduction projects, while also focusing on identifying opportunities to use natural gas more efficiently. Energy Specialist positions are funded by FortisBC up to $60,000 for a period of one year. This Program has been funded as an enabling program.					
Target Market	Service Region					
New vs Retrofit	Retrofit					
Eligible Measures	Energy Specialist position					
Incremental Measure Cost	$60,000					
Incentive Amount	$60,000					
Savings Per Participant	Total 2012 verified (non-EEC program) annual natural gas savings = 1,081 GJs/year					
Measure Life & Source	N/A					
Free Rider Rate & Source	0% - Learnings from 2012/2011 Energy Specialist Pilot Program					
Participants	Service Region	2012 Projected	2012 Actual			
	FEI	14	16			
	FEVI	2	3			
	FEW	0	0			
	Total	16	19			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	729	3	0	68	800
	FEVI	180	1	0	8	188
	FEW	0	0	0	0	0
	Total	909	3	0	76	989

Notes:

- Some organizations had Energy Specialists for part of the year only.
- The Prince George Community Energy Manager funding has been included in the Energy Specialist Program for both projected and actual expenditures. The Prince George Community Energy Manager was a joint funding partnership between the City of Prince George, FEI, BC Hydro and NRCan. FEI's funding contribution was $25,000 per year. FEI discontinued funding of this position in May 2012 after the City of Prince George decided it would no longer support the position.
- The energy savings listed apply only to third party verified natural gas projects completed by Energy Specialists in 2012 which did not directly receive incentive funding from another EEC program. These energy savings are only reported and have not been included in the calculations for the benefit/cost tests as the required inputs are not available.

7.3 Other Commercial Energy Efficiency Program Area Initiatives

In addition to the formal programs detailed in the tables above, the Commercial Energy Efficiency group also invested funding and a considerable amount of time in collaborative initiatives with the FortisBC Inc. electric utility in the shared services territory. More specifically, 2012 saw the launch of both the Product Rebate Program and the On-Line Energy Advisor, described immediately below.

- The Product Rebate Program (to be rebranded as the Energy Rebate Centre in March of 2013) represents the EEC group's initial attempt at allowing rebate applications to be filled out online. It allows customers in the shared services territory to apply for both electric and natural gas rebates via a single, online portal. This reduces the administrative burden that program participants would have otherwise faced when having to apply to multiple programs independently. It is expected that this will also decrease the administrative burden on program administrators.
- The Online Energy Advisor provides small and mid-sized business customers in the shared services territory with an online interactive energy assessment to identify their energy management issues and provides customers with an initial, high level conservation action plan. The Online Energy Advisor also highlights any applicable FortisBC rebates (from either the natural gas or electric utility) and directs participants to the Product Rebate Program in order to apply.

As these are not programs in the traditional sense (with attributable GJ savings, incremental measure costs, measure lives, free ridership etc.) they are not presented in tabular format below. EEC funds invested in the development and launch of both the Product Rebate Program and the Online Energy Advisor have been captured under the Commercial Energy Efficiency Program Area's general administration and communications expenditures.

7.4 2012 Commercial Energy Efficiency Programs Planned but not Launched

7.4.1 PROCESS HEAT PROGRAM

The Process Heat Program could not be launched in 2012 as Commercial Energy Efficiency Program Area resources were fully committed to other initiatives. Development of this program has been assigned to the Industrial Energy Efficiency Program Area. See Section 9 for additional details.

7.5 2012 Commercial Energy Efficiency Program Closures

7.5.1 LIGHT COMMERCIAL BOILER PROGRAM

The Light Commercial Boiler Program was folded into the Efficient Boiler Program upon its re-launch in May of 2012. This was done for several reasons, listed below:

- There appeared to be little need to have a boiler incentive program specifically dedicated to smaller boilers.
- To harmonize the boiler incentives across all boiler sizes.

- To reduce confusion and administrative burden among potential program participants, as well as to reduce the administrative burden on the Companies.

7.6 Summary

Commercial Energy Efficiency Program Area activity in 2012 successfully achieved over 150,000 GJ/year of natural gas savings and a positive TRC of 1.2. The Efficient Boiler Program was considerably simplified, reducing the burden on both program participants and the Companies, while clarifying the rebate amounts. Additional programs, such as the Commercial Kitchen Program, the Continuous Optimization Program and the EnerTracker Program, were either rolled out or are set to be rolled out early in 2013. In addition, new collaborative efforts with the FortisBC Inc. electric utility were rolled out over the course of the year, providing customers with online tools including a self-assessment tool (Online Energy Advisor) and an application portal (Product Rebate Program).

8 INNOVATIVE TECHNOLOGIES PROGRAM AREA

8.1 Overview

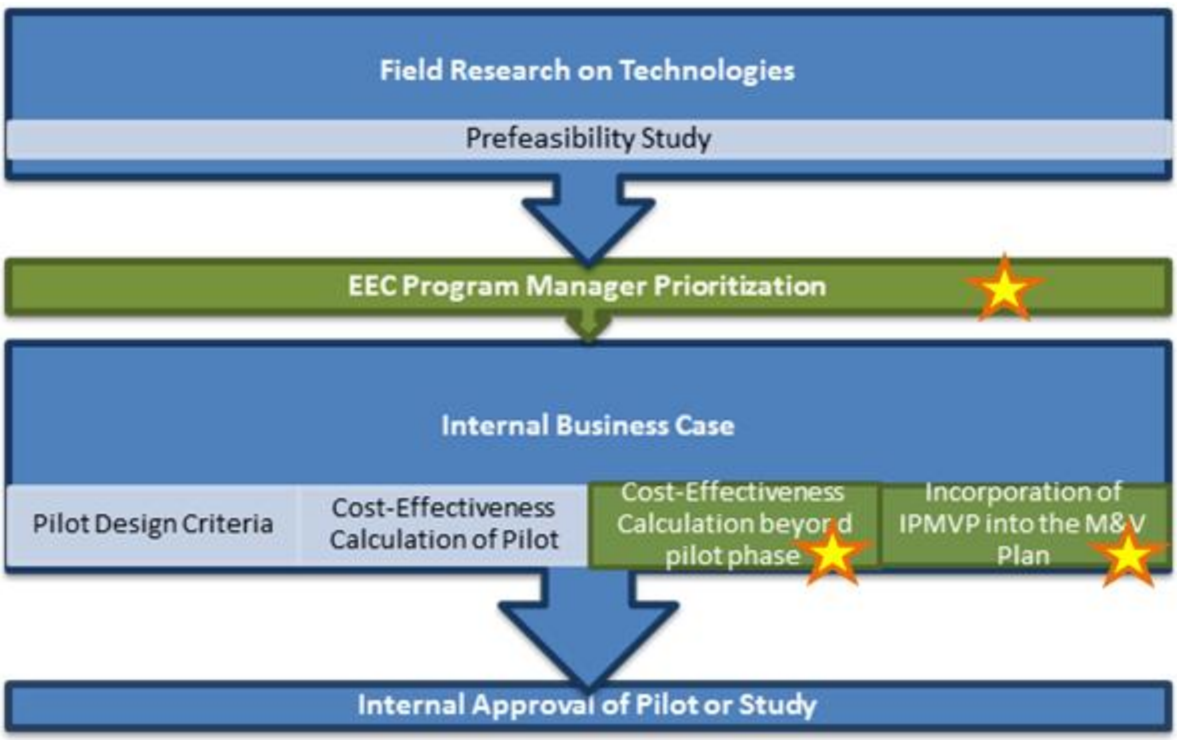
A primary objective of the Innovative Technologies Program Area is to identify market-ready technologies that are not yet widely adopted in British Columbia, and which are suitable for the development of or inclusion in the portfolio of ongoing EEC programs in other Program Areas. This is accomplished through prefeasibility studies to evaluate technology details and its market conditions, pilots to conduct technology field trials limited to a small subset of customers and the use of EM&V protocols to validate manufacturers' claims related to equipment and system performance. In 2012, interim results from two of the Innovative Technology investigations were incorporated into the design and development of Residential EEC programming. A number of other projects initiated in 2012 also appear to be uncovering important results that should similarly be incorporated into future EEC programming.

Just as important as identifying new technologies that should be incorporated into the EEC portfolio are findings that indicate which technologies should not. Section 8.3 discusses how the activities and processes for the Innovative Technologies Program Area were successful in identifying proposed projects that should not proceed to full pilot phase or further. Part of this success can be attributed to the continued refining of technology screening and selection process protocols. In 2012, the following enhancements to the screening process were made:

- EEC Program Manager Prioritization – a deliberate process step that engages non-Innovative Technologies EEC Program Managers in the screening process to ensure that technologies being investigated line up with their highest programming priorities.
- Cost-Effectiveness Calculations (beyond pilot phase) – this step takes a conservative look forward at the technology and operational costs that might be incorporated into a full future EEC program to ensure that preliminary data are indicating an acceptable cost effectiveness.
- Measurement and Verification ("M&V) Plans for pilots and studies with incorporation of the International Performance Measurement & Verification Protocol ("IPMVP") – the Companies have incorporated the IPMVP into the measurement and verification plans and studies to provide assurance that best industry practices are used to determine the cost-effectiveness of innovative technologies considered for future EEC programming.

Figure 8.1 shows how these new steps have been formalized into the screening process. The intent of these improvements is to increase the likelihood that completed pilots will result in new or improved EEC programs in other Program Areas.

Figure 8.1 – 2012 Enhancements to the Innovative Technologies Screening Process



Note:

- Stars indicate new process steps for 2012 forward.

All 2012 activities undertaken in this Program Area meet the definition of technology innovation programs as set out in the Demand-Side Measures Regulation. It should be noted that Innovative Technologies are considered a specified demand-side measure,[9] meaning that the Program Area or the measures therein are not subject to a cost-effectiveness test. Instead the cost-effectiveness of these expenditures will be evaluated as part of the DSM portfolio as a whole.[10] Innovative Technologies expenditures are also not subject to the 33 percent cap on programs for which the MTRC is utilized as a cost-effectiveness measure according to Section 4 (4) of the Demand-Side Measures Regulation.[11]

Table 8.1 summarizes the projected and actual expenditures for the Innovative Technologies Program Area in 2012, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results where applicable

[9] BCUC Log No. 36730, Request for Clarification of Order G-44-12 and Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application

[10] Subsection 4(4) of the Demand-Side Measures Regulation, and the Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application, page 175.

[11] BCUC Log No. 36730, Request for Further Clarification of Order G-44-12 and Decision on the 2012 – 2013 Revenue Requirements Application and Natural Gas Rates Application and the Commission's May 11, 2012 letter.

Table 8-1: 2012 Innovative Technologies Program Area Results Summary

Program and Service Territory	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Pilot/Demonstration Projects														
Residential High Efficiency Water Heater Pilot														
FEI	0	367	3,608	0	92	0	87	0	179	0.1	n/a	0.1	1.3	0.1
FEVI	0	39	410	0	9	0	9	0	18	0.2	n/a	0.2	4.0	0.2
Total	0	406	4,018	0	102	0	96	0	198					
ENERGY STAR© 0.67 Storage Tank Water														
FEI				0	0	0	49	0	49					
FEVI		No Direct Savings		0	0	0	1	0	1			No Direct Savings		
Total				0	0	0	50	0	50					
AHU Coil Cleaning Pilot														
FEI				0	0	0	0	0	0					
FEVI		No Direct Savings		0	0	0	5	0	5			No Direct Savings		
Total				0	0	0	5	0	5					
City of Courtenay Pool Heating Project														
FEI				0	0	0	0	0	0					
FEVI		No Direct Savings		0	0	0	16	0	16			No Direct Savings		
Total				0	0	0	16	0	16					
City of Vancouver Residential Solar Water Heating Pilot														
FEI				0	0	0	-6	0	-6					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	-6	0	-6					
Studies and Memberships														
Thermal Performances of Building Envelope Assemblies for Mid- and High-Rise Buildings in B.C.														
FEI				0	0	0	25	0	25					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	25	0	25					
Review of Packaged Rooftop Equipment (RTU) Upgrades for DSM Utility programs														
FEI				0	0	0	33	0	33					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	33	0	33					
Energy Savings Potential Using Occupancy Sensors														
FEI				0	0	0	16	0	16					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	16	0	16					
Geoexchange BC – Phase 1 Energy Performance Evaluation Project														
FEI				0	0	0	10	0	10					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	10	0	10					
Transpired Solar Collector Market Study														
FEI				0	0	0	29	0	29					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	29	0	29					
Pre-Feasibility Study Microwave Assist Technology														
FEI				0	0	0	5	0	5					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	5	0	5					
Pre-Feasibility Study Catalytic Radiant Burner Technology														
FEI				0	0	0	4	0	4					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	4	0	4					
CEATI Membership														
FEI				0	0	0	9	0	9					
FEVI		No Direct Savings		0	0	0	0	0	0			No Direct Savings		
Total				0	0	0	9	0	9					
ALL PROGRAMS														
FEI	**0**	**367**	**3,608**	**0**	**92**	**0**	**261**	**0**	**353**	**0.1**	**n/a**	**0.1**	**1.3**	**0.1**
FEVI	**0**	**39**	**410**	**0**	**9**	**0**	**31**	**0**	**40**	**0.1**	**n/a**	**0.1**	**4.0**	**0.1**
Total	**0**	**406**	**4,018**	**0**	**102**	**0**	**292**	**0**	**394**	**0.1**	**n/a**	**0.1**	**1.4**	**0.1**

Notes:

- The Residential High Efficiency Water Heater Pilot was listed in the Residential Program Area in 2011. It is now being reported in the Innovative Technologies Program Area for 2012 due to the innovative nature of the technologies being tested.

- In 2012, the Companies received a $20,000 contribution from the City of Vancouver towards the M&V of the City of Vancouver Residential Solar Water Heating Pilot. The actual M&V costs incurred for this activity 2012 were approximately $14,000, which resulted in a negative expenditure amount of $6,000.

8.2 2012 Innovative Technologies Activities

Tables 8-2, 8-3 and 8-4 summarize the pilots, studies and membership activities, respectively undertaken in 2012, including pilot and measure descriptions and a breakdown of non-incentive spending[12].

[12] As Innovative Technologies activities are not considered formal EEC programs, they were not presented in individual program tables as in other Program Area sections in this report.

Table 8-2: Pilots

Program Description	Evaluating market-ready technologies and conducting small scale pilots to gather data to validate manufacturers' claims about measure system performance and energy savings. The data from pilots can also be used to help improve the quality and installation of future systems, and to understand and reduce market barriers. Technologies that successfully emerge from the Innovative Technologies Program will be considered for inclusion in the various program areas within the larger EEC portfolio.
Target Market	Variable
New vs Retrofit	Retrofit
Residential High Efficiency Water Heater Pilot	The Companies are conducting a pilot program as part of their domestic hot water heater market transformation strategy. The research is in support of proposed federal Energy Efficiency Act standards for 0.80 technologies in 2020. The purpose of the program is to obtain installation, performance and customer acceptance information regarding residential Domestic Hot Water ("DHW") technologies with an Efficiency Factor ("EF") of 0.80 or better. Research is being conducted as a collaborative initiative between the Canadian Gas Association (CGA), Natural Gas Technology Centre (NGTC) and other utilities.
	Service Region Participants FEI 43 FEVI 5 Total 48
ENERGY STAR© 0.67 Storage Tank Water Heater Pilot	Pilot to determine the efficiency and savings of 0.67 EF and 0.70 EF water heaters by assessing their performance under various household profiles as well as understanding the installation concerns such as electrical wiring, space considerations and venting. The data will be used to support proposed regulation of increased minimal efficiency standards of water heaters to .67 by 2016 as well as supporting the Residential Energy Star Domestic Hot Water program.
	Service Region Participants FEI 9 FEVI 1 Total 10
AHU Coil Cleaning Pilot	Pilot to evaluate savings projections, understand potential technical barriers and explore both barriers and opportunities for market promotion with regards to Air Handling Unit (AHU) coil cleaning practices in hospitals. Gas savings are achieved through cleaner coils in the AHU, reducing the workload on the gas boiler that heats the hot water for the system. This pilot commenced in 2012 and is projected to deliver validated measurement data by 2013. This may provide input for a potential prescriptive commercial program to launch in 2014.
	Service Region Participants FEI 0 FEVI 1 Total 1
City of Courtenay Solar Pool Demonstration Project	Collaboration with the City of Courtenay to demonstrate Solar thermal pool heating on a highly attended and highly visible recreation facility in downtown Courtenay. The Companies provided $29,572 in incentives to support this project and to gather real data on the performance and energy savings for outdoor recreational pool heating using solar thermal unglazed collectors.
	Service Region Participants FEI 0 FEVI 1 Total 1
City of Vancouver Residential Solar Water Heating Pilot	Pilot project initiated by the City of Vancouver, Offsetters and SolarBC to promote the installation of 30 Solar Hot Water systems in Vancouver. The Companies have committed $50,000 to support this project and to gather real data and validate the energy systems claims.
	Service Region Participants FEI 30 FEVI 0 Total 30

Table 8-2: Pilots (Continued)

Participants	Service Region	2012 Projected	2012 Actual			
	FEI	0	82			
	FEVI	0	8			
	FEW	0	0			
	Total	0	90			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	92	4	7	121	224
	FEVI	9	2	1	27	40
	FEW	0	0	0	0	0
	Total	102	6	8	148	263

Table 8-3: Studies

Description	In order to evaluate market-ready technologies, it is important to participate in technology performance studies. The main objectives of these initiatives are to help validate energy savings claims and stay abreast of additional market available technologies, while collaborating and sharing costs amongst other gas and electric utilities. The Companies have commissioned studies to determine the energy-saving potential, market availability and barriers, adoption rate and claimed energy savings associated with a variety of technologies.
Target Market	Variable
New vs Retrofit	N/A
Thermal Performances of Building Envelope Assemblies for Mid- and High-Rise Buildings in B.C.	Study managed by BC Hydro. Improving the thermal resistance of building envelopes is the single-most effective measure for reducing energy loads associated with space heat loss and gains. Over 50% of building space heating energy consumption is generated by heat transfer and air leakage through envelope assemblies. The study will gather wall assemblies and innovative technologies that would reduce conductance.
Review of Packaged Rooftop Equipment Upgrades for DSM Utility programs	Study through the CEATI Customer Energy Solutions Interest Group ("CESIG") to review packaged roof top unit ("RTU") upgrades for DSM utility Programs. the objective is to complete a market and technical assessment of current and emerging RTU equipmen, in order to determine gas and electricity savings in the commercial and institutional building sector.
Energy Savings Potential Using Occupancy Sensors	Study through CEATI (CESIG) to assess the technical savings potential of occupancy-based controls, as well as their overall conservation potential within the service territories of the three sponsoring utilities: Enbridge Gas Distribution, SaskPower and FortisBC. Although the majority of market activity to date has involved occupancy sensors applied as a lighting control strategy, the study also examines the potential for occupancy-based controls in emerging applications, including heating, ventilation & air conditioning ("HVAC") and plug load controls.
Geoexchange BC – Phase 1 Energy Performance Evaluation Project	Study through GeoexchangeBC and BC Hydro to conduct a review of the operational performance of ground-coupled heat pump systems (geo-exchange heat pumps) installed over a range of building types and locations in British Columbia. This work compared the electrical and natural gas consumption in geo-exchange buildings relative to conventional buildings to assess the energy savings from the technology.
Transpired Solar Collector Market Study	Study facilitated by FortisBC to assess a market assessment of transpired solar collectors within British Columbia. The report provides a review of the current adoption rate of the technology and its market barriers as well as an assessment of the incremental costs.
Pre-Feasibility Study Microwave Assist Technology	Microwave Assist Technology ("MAT") is a dual fuel or hybrid process developed for the ceramic industry. MAT is applied during the heat treatment process which exposes the object simultaneously to microwave energy and radiant conventional heat. This technique significantly reduces the heating time as the object experiences volumetric heating through microwaves and convective heating at the same time. The main benefits have claimed energy consumption reductions in the range of 50-60% due to reduced heating time of approximately 50% and lowered heating temperature.
Pre-Feasibility Study Catalytic Radiant Burner Technology	Catalytic infrared technology is a recent advancement in the heat treatment industry whereby radiant heat is produced through a flameless catalytic process. It has claimed natural gas savings of approximately 30-50% over Convection Heating (base case).

Table 8-3: Studies (continued)

Participants	Service Region	2012 Projected	2012 Actual			
	FEI	0	0			
	FEVI	0	0			
	FEW	0	0			
	Total	0	0			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	122	122
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	0	0	122	122

Table 8-4: Memberships

Description	Participating in industry memberships allows the Companies to stay abreast of market available technologies, while collaborating and sharing costs amongst other gas and electric utilities.					
CEATI Membership	The Companies participate in CEATI's Gas Utilization Working Group, which has identified possible areas for collaboration, including solar thermal, motion sensor thermostats, combined heat and power ("CHP"), gasification of biomass and water heating technology. The group will collaborate with utilities and stakeholders on potential studies, pilots, and demonstration projects which will be used to confirm savings claims and guide the development of future programs.					
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	9	9
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	0	0	9	9

8.3 Innovative Technologies Activities Planned for 2012 But Not Launched

In the 2012-2013 EEC Plan the Companies identified pilot and demonstration projects to be the primary areas of focus, subject to results from prefeasibility studies. Studies conducted to assess the value of these activities resulted in the decision not to move forward with them. In some cases the initiatives were deemed by Program Managers to be unfeasible and in other cases not priorities for 2012.

The following Innovative Technology Programs listed in the 2012-2013 EEC Plan were not launched in 2012:

8.3.1 THERMAL CURTAINS

A study conducted by Prism Engineering originally identified the use of thermal curtains for greenhouse applications as a potential energy management opportunity. However, following the completion of the 2012-2013 EEC Plan, a further prefeasibility study came back from Prism Engineering indicating that Thermal Curtains already had a high adoption rate in British Columbia and thus didn't qualify as an innovative technology.

8.3.2 SOLAR AIR HEATING SYSTEM

A prefeasibility study was completed for Q2 of 2012; however, due to the limited market potential, the program was deemed a low priority by Program Managers and was deferred to allow other, higher priority programs to proceed in 2012.

8.3.3 OCCUPANCY SENSORS/CONTROLS

The Companies are awaiting results from the Occupancy Control to Unit Ventilator Pilot[13] before moving forward with this initiative.

8.4 Summary

Innovative Technologies represent a key component of the Companies' overall commitment to EEC activities by identifying viable technologies and projects that have the potential to support the development of new programs within the larger EEC portfolio. Although it is too early to report on pilots resulting in programs, there are outcomes from the Residential High Efficiency Water Heater Pilot and the ENERGY STAR© 0.67 Storage Tank Water Heater Pilot which were used toward the design of the ENERGY STAR © Domestic Water "DHW" Technologies Program. These initial outcomes were:

- Initiating relationships with key stakeholders and policy makers
- Gathering a list of technologies that meet the minimum efficiency levels
- Determining the availability of the technology
- Determining the demand for that technology amongst participants
- Determining retail and installed costs for the technologies
- Tracking any installation barriers or the need for contractor education

Overall, the Innovative Technology initiatives were successful in achieving results in evaluating the feasibility of new technologies as well as being used towards the design of future EEC programs. While the framework for Innovative Technologies continues to evolve, the evidence demonstrates that it has come a long way in making sure that innovative technologies are selected with care using consistent criteria to ensure the greatest potential for further development as full programs in other areas of the EEC Portfolio.

[13] The expenditures for the Occupancy Control to Unit Ventilator Pilot were reported in the 2011 EEC Annual Report. The final analysis will be conducted and report prepared in Q4, 2013.

9 INDUSTRIAL ENERGY EFFICIENCY PROGRAM AREA

9.1 Overview

The Industrial Energy Efficiency Program Area designs and manages programs to encourage Industrial and Manufacturing customers who use natural gas for process heat to engage in energy efficiency projects. In 2012, the Industrial Energy Efficiency Program Area achieved an overall TRC of 2.3, accomplished by one project from the Technology Retrofit Program with estimated savings of over 70,000 GJ/year. Activities in the Energy Audit and Analysis Program resulted in several energy audit reports that identified projects in industrial facilities that provide potential future natural gas savings of over 400,000 GJ/year. Relationships with key industry players were also enhanced in 2012 in order to identify industrial customers' motivations and incentive levels and increase the future uptake of Industrial Energy Efficiency programs.

Table 9-1 summarizes the projected and actual expenditures for the Industrial Energy Efficiency Program Area in 2012, including incentive and non-incentive spending, annual and NPV gas savings, as well as TRC and other cost-effectiveness test results.

Table 9-1: 2012 Industrial Energy Efficiency Program Results Summary

Program and Service Territory	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Non Program Specific Expenses														
FEI	No Direct Savings			0	0	0	8	0	8	No Direct Savings				
FEVI				0	0	0	0	0	0					
Total				0	0	0	8	0	8					
Technology Retrofit Program														
FEI	72,587	70,000	474,187	595	250	89	19	684	269	2.3	n/a	4.9	2.1	1.4
FEVI	0	0	0	0	0	0	0	0	0	n/a	n/a	n/a	n/a	n/a
Total	72,587	70,000	474,187	595	250	89	19	684	269					
Energy Audit & Analysis Program														
FEI	No Direct Savings			353	43	35	1	388	45	No Direct Savings				
FEVI				0	10	0	0	0	10					
Total				353	53	35	2	388	55					
Process Heat Program														
FEI	No Direct Savings			208	0	5	20	212	20	No Direct Savings				
FEVI				23	0	0	0	24	0					
Total				231	0	5	20	236	20					
Customer Energy Analysis														
FEI	No Direct Savings			0	0	0	5	0	5	No Direct Savings				
FEVI				0	0	0	0	0	0					
Total				0	0	0	5	0	5					
ALL PROGRAMS														
FEI	**72,587**	**70,000**	**474,187**	**1,155**	**293**	**129**	**54**	**1,284**	**347**	**2.3**	**n/a**	**4.7**	**2.1**	**1.4**
FEVI	**0**	**0**	**0**	**23**	**10**	**0**	**0**	**24**	**10**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
Total	**72,587**	**70,000**	**474,187**	**1,179**	**303**	**129**	**54**	**1,308**	**358**	**2.3**	**n/a**	**4.7**	**2.1**	**1.4**

Notes:

- The Energy Audit & Analysis Program does not include direct savings as the incentives are aimed only at identifying energy saving opportunities (see Table 9-3 for details).
- Process Heat Program development activities were initiated in 2012; therefore, the program does not include direct savings (see Table 9-4 for details).

- The Customer Energy Analysis Program was closed in 2011. An outstanding invoice was paid in the first quarter of 2012. Since there was no other program activity in 2012, program specific details are not included in Section 9. Please see Section 9.2 of the 2011 EEC Annual Report for details.

9.2 2012 Industrial Energy Efficiency Programs

The following tables outline the specific Industrial Energy Efficiency programs undertaken in 2012, including program and measure descriptions and a breakdown of non-incentive spending.

Table 9-2: Technology Retrofit Program (new)

Program Description	This program provides eligible customers with funding to encourage the implementation of any cost effective retrofits to industrial processes using natural gas as process heat or energy source. The expected energy savings, measures, incentives, measure cost and life will necessarily vary depending on the customer, though each project is subjected to a TRC test and must be approved by the utility.				
Target Market	Medium and Large Industrial Facilities				
New vs Retrofit	Retrofit				
Eligible Measures	Variable				
Incremental Measure Cost	Dependent upon participant's proposed Energy Saving Measures.				
Incentive Amount	If TRC ≥ 1.0 then $5 / GJ saved over 3 years				
Savings Per Participant	Variable				
Measure Life & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.				
Free Rider Rate & Source	Variable. Dependent upon participant's proposed Energy Saving Measures.				
Participants	Service Region	2012 Projected	2012 Actual		
	FEI	4	1		
	FEVI	0	0		
	FEW	0	0		
	Total	4	1		
Expenditures ($,000s)	2012				
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	250	1	3	15	269
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	250	1	3	15	269

Notes:

- The 2011 EEC Annual Report included separate tables for the Heat Exchanger Pilot and Burner Management System Programs. In the 2012-2013 EEC Plan both projects were included in the Technology Retrofit Program.
- The Burner Management System Program was cancelled by the client and no incentives were paid in 2012.
- In the 2012-2013 EEC Plan the Technology Retrofit Program only focused on four eligible technologies. In 2012 the scope of the program was widened to any cost-effective retrofits to industrial processes using natural gas as process heat or energy source.

Table 9-3: Energy Audit and Analysis Program

Program Description	This program provides eligible customers with funding toward the completion of an energy audit report aimed at identifying energy saving opportunities in industrial manufacturing processes using natural gas as process heat or energy source. Participants hire a Certified Energy Manager or Professional Engineer to conduct an energy audit of their facility and write an energy audit report. Each energy audit report describes the facility and lists possible efficiency upgrades and/or technology replacements focused on natural gas saving opportunities.
Target Market	Medium and Large Industrial Facilities
New vs Retrofit	Retrofit
Eligible Measures	Industrial energy audit
Incremental Measure Cost	N/A
Incentive Amount	-For eligible customers consuming less than 150,000 GJ/yr of natural gas, the lesser of 50% of the cost of energy audits or $20,000* -For eligible customers consuming more than 150,000 GJ/yr of natural gas, the lesser of 75% of the cost of energy audits or $40,000* * Clients might be eligible to receive 100% of the cost of the audit, up to the maximum amount, if any of the energy efficient upgrades identified in the report are implemented
Savings Per Participant	Variable
Measure Life & Source	Variable
Free Rider Rate & Source	10% for audits (best estimate)

Participants

Service Region	2012 Projected	2012 Actual
FEI	35	4
FEVI	0	1
FEW	0	0
Total	35	5

Expenditures ($,000s)

2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	43	0	1	0	45
FEVI	10	0	0	0	10
FEW	0	0	0	0	0
Total	53	1	1	0	55

Notes:

- The Energy Audit and Analysis Program does not include direct savings as the incentives are aimed only at identifying energy saving opportunities. The client is not required to implement energy saving projects identified in the audit process.
- If the client decides to implement any of the projects identified in the audit process, then the client has to apply to the Technology Retrofit Program to receive incentives. Direct savings from each approved project will be included in the Technology Retrofit Program.
- The Industrial Energy Efficiency Program Area cost-effectiveness ratios include the incentives and other costs attributed to the Energy Audit and Analysis Program.

Table 9-4: Process Heat Program (new)

Program Description	This program provides rebates to encourage energy efficiency retrofits targeted towards manufacturing processes.					
Target Market	Medium and Large Industrial Facilities					
New vs Retrofit	Retrofit					
Eligible Measures	Medium and high efficiency boilers, heat recovery economizers, boiler controls					
Incremental Measure Cost	TBD					
Incentive Amount	TBD					
Savings Per Participant	TBD					
Measure Life & Source	TBD					
Free Rider Rate & Source	TBD					
Participants	Service Region	2012 Projected	2012 Actual			
	FEI	21	0			
	FEVI	2	0			
	FEW	0	0			
	Total	23	0			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	20	0	0	20
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	20	0	0	20

Notes:

- In both the 2011 EEC Annual Report and the 2012-2013 EEC Plan, the Process Heat Program was included in the Commercial Energy Efficiency Program Area. This program was moved to the Industrial Energy Efficiency Program Area in 2012 as it targets primarily industrial customers.
- The program development activities were initiated in 2012 and the Companies anticipate launching this program in 2013.

9.3 Summary

The Companies are satisfied with the results of the Industrial Energy Efficiency Program Area in 2012. Two new projects initiated in 2012 for the Technology Retrofit Program are planned to be commissioned in 2013. In addition, nine energy audits reports are expected to be submitted in 2013.

Progress has been made toward developing a long-term strategy to identify the most efficient way to achieve substantial natural gas savings and GHG emissions reductions, while attending to the needs of the Company's industrial customers. By having a clear roadmap, the Industrial Energy Efficiency Program Area will continue to represent a considerable opportunity for the Companies to achieve their energy efficiency goals.

10 CONSERVATION, EDUCATION AND OUTREACH INITIATIVES

10.1 Overview

The CEO Program Area was successful in launching all but one program presented in the 2012-2013 EEC Plan, while effectively collaborating with other British Columbia utilities in 2012. This increased collaboration with the FortisBC Inc. electric utility optimized expenditures by integrating print communications, booth displays and production items for various events and campaigns occurring in the shared services territory. Steps were also taken in 2012 toward increased collaboration with BC Hydro in sharing best practices on partnership negotiations and outreach tactics. Ongoing collaboration in delivering the energy conservation message is planned for 2013 through joint or side-by-side booth space at six outreach events. This growing partnership with other British Columbia utilities addresses the Commission's directive from the 2012-2013 RRA Decision to pursue opportunities for increased collaboration on CEO activities[14].

As CEO programs are generally informational and education based, promoting behaviour change with no cost to the customer and no incentives provided, there are currently no energy savings attributed to CEO activities in 2012. The following tables do not contain information about eligible measures, incentive amounts, savings levels, free ridership, spillover or participation levels. CEO costs are included at the portfolio level and incorporated into the overall EEC portfolio TRC.

Although there were no energy savings attributed to the CEO Program Area in 2012, it should be noted that the Companies continue to explore ways to identify and confirm energy savings from CEO activities. If sufficient evidence becomes available, these savings may be claimed in future EEC Annual Reports.

Table 10-1 summarizes the projected and actual expenditures for the CEO Program Area in 2012. Based on the campaign, key message and location, several of the costs, particularly production materials, outreach and advertisements, were proportionally shared between CEO and other EEC Program Areas, as well as with various departments in the Companies and with FortisBC Inc. in order to maximize cost efficiency.

[14] 2012-2013 RRA Decision, April 12, 2012. p.160.

Table 10-1: 2012 CEO Initiative Results Summary

Program and Service Territory	Annual Gas Savings (GJ/yr.) 2012-2013 EEC Plan	Annual Gas Savings (GJ/yr.) 2012 Actual	Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s) Incentives 2012-2013 EEC Plan	Incentives 2012 Actual	Non-Incentives 2012-2013 EEC Plan	Non-Incentives 2012 Actual	All Spending 2012-2013 EEC Plan	All Spending 2012 Actual	Benefit/Cost Ratios TRC	MTRC	Utility	Participant	RIM
Residential and General Public														
Residential Mass Education on Conservation and Energy Literacy														
FEI				0	0	236	232	236	232					
FEVI		No Direct Savings		0	0	26	28	26	28			No Direct Savings		
Total				0	0	262	260	262	260					
Residential Home Shows and Community Events Outreach														
FEI				0	0	585	541	585	541					
FEVI		No Direct Savings		0	0	65	61	65	61			No Direct Savings		
Total				0	0	650	602	650	602					
Canadian Home Builders' Association Promotions and Support														
FEI				0	0	90	23	90	23					
FEVI		No Direct Savings		0	0	10	17	10	17			No Direct Savings		
Total				0	0	100	40	100	40					
Residential Outreach Education Tools														
FEI				0	0	135	93	135	93					
FEVI		No Direct Savings		0	0	15	18	15	18			No Direct Savings		
Total				0	0	150	111	150	111					
Energy Champion Program														
FEI				0	0	360	252	360	252					
FEVI		No Direct Savings		0	0	40	59	40	59			No Direct Savings		
Total				0	0	400	311	400	311					
Home Efficiency Measures														
FEI				0	0	162	17	162	17					
FEVI		No Direct Savings		0	0	18	0	18	0			No Direct Savings		
Total				0	0	180	17	180	17					
Municipal Partnerships – Other														
FEI				0	0	115	8	115	8					
FEVI		No Direct Savings		0	0	10	1	10	1			No Direct Savings		
Total				0	0	125	9	125	9					
Commercial Customers														
Medium-Large Commercial Education Sessions														
FEI				0	0	25	39	25	39					
FEVI		No Direct Savings		0	0	3	9	3	9			No Direct Savings		
Total				0	0	28	48	28	48					
Small Commercial Education and Outreach														
FEI				0	0	125	68	125	68					
FEVI		No Direct Savings		0	0	10	7	10	7			No Direct Savings		
Total				0	0	135	75	135	75					
Commercial Trade Shows and Association Events														
FEI				0	0	170	77	170	77					
FEVI		No Direct Savings		0	0	20	4	20	4			No Direct Savings		
Total				0	0	190	81	190	81					
Behaviour Programs - Online Community Site														
FEI				0	0	125	67	125	67					
FEVI		No Direct Savings		0	0	15	0	15	0			No Direct Savings		
Total				0	0	140	67	140	67					
Behaviour Programs - Energy Specialists														
FEI				0	0	72	14	72	14					
FEVI		No Direct Savings		0	0	8	3	8	3			No Direct Savings		
Total				0	0	80	17	80	17					
Conservation Assistance														
Conservation Assistance - Education and Outreach														
FEI				0	0	125	29	125	29					
FEVI		No Direct Savings		0	0	15	5	15	5			No Direct Savings		
Total				0	0	140	34	140	34					

Table 10-1: 2012 CEO Initiative Results Summary (continued)

Program and Service Territory	Annual Gas Savings (GJ/yr.) 2012-2013 EEC Plan	Annual Gas Savings (GJ/yr.) 2012 Actual	Actual NPV Gas Savings (GJ)	Incentives 2012-2013 EEC Plan	Incentives 2012 Actual	Non-Incentives 2012-2013 EEC Plan	Non-Incentives 2012 Actual	All Spending 2012-2013 EEC Plan	All Spending 2012 Actual	TRC	MTRC	Utility	Participant	RIM
School Outreach														
School Programs: Class and Online Curriculum														
FEI				0	0	18	9	18	9					
FEVI		No Direct Savings		0	0	2	4	2	4			No Direct Savings		
Total				0	0	20	13	20	13					
School Programs: K-12 In-Class Programs and Presentations														
FEI				0	0	400	344	400	344					
FEVI		No Direct Savings		0	0	50	68	50	68			No Direct Savings		
Total				0	0	450	412	450	412					
School Programs: K-12 Home Efficiency Measures														
FEI				0	0	90	1	90	1					
FEVI		No Direct Savings		0	0	10	0	10	0			No Direct Savings		
Total				0	0	100	1	100	1					
School Programs: Post Secondary														
FEI				0	0	165	96	165	96					
FEVI		No Direct Savings		0	0	20	7	20	7			No Direct Savings		
Total				0	0	185	103	185	103					
ALL PROGRAMS														
FEI				**0**	**0**	**2,998**	**1,909**	**2,998**	**1,909**					
FEVI		**No Direct Savings**		**0**	**0**	**337**	**291**	**337**	**291**			**No Direct Savings**		
Total				**0**	**0**	**3,335**	**2,200**	**3,335**	**2,200**					

10.2 2012 CEO Programs

Tables 10-2 through 10-18 outline the CEO initiatives undertaken in 2012. This includes program descriptions as well as a breakdown of spending, all of which is classified as "non-incentive spending".

Table 10-2: Residential Mass Education on Conservation and Energy Literacy (new)

Program Description	This program promotes natural gas conservation and energy literacy by providing consumers with the information they need to make smart energy choices. In 2012, a new online energy calculator and a comprehensive education campaign to aid customers in their decision making on appliances, fuel costs and conservation were launched. The online energy calculator allows residential customers to compare their estimated annual energy costs between fuel types and also the annual energy cost of various home appliances. The comprehensive advertising campaign included print advertising in local community newspapers, online advertisements and radio spots for both mainstream and ethnic audiences.
Target Market	Residential customers and general public
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research &	Total
FEI	0	21	211	0	232
FEVI	0	1	27	0	28
FEW	0	0	0	0	0
Total	0	22	238	0	260

Table 10-3: Residential Home Shows and Community Events Outreach

Program Description	This program supports direct face-to-face interactions and online engagement with customers through regional home shows, community outreach events, hardware and grocery stores, contests and online behavioural pledges. In 2012, the Companies engaged with approximately 60,000 residential customers on topics such as home renovations, equipment upgrades and energy savings. Development of a new pilot program targeting ethnic customers through face-to-face, in-home education began in 2012, and will be launched in 2013. A key development in this area was the increased collaboration with the FortisBC Inc. electric utility on several events. Steps were also taken toward increased collaboration with BC Hydro on sharing best practices on partnership negotiations and outreach tactics, and there will be collaboration in delivering the energy conservation message together through a joint booth space or side-by-side location at 6 events in 2013.
Target Market	Residential customers and general public
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	443	98	0	541
FEVI	0	51	10	0	61
FEW	0	0	0	0	0
Total	0	494	108	0	602

Table 10-4: Canadian Home Builders' Association Promotions and Support

Program Description	This program encourages energy efficiency practices by supporting regional Canadian Home Builders' Association (CHBA) events such as green building awards, home shows and education sessions targeted at residential customers.
Target Market	Builders/renovators, Association members and general public
New vs Retrofit	Both
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	21	1	0	22
FEVI	0	15	1	0	17
FEW	0	0	0	0	0
Total	0	36	3	0	39

Table 10-5: Residential Outreach Education Tools

Program Description	These tools include production materials, booth collateral, energy saving giveaways such as five minute shower timers, weatherstripping and other prizes to enable customers to practice energy conservation at home. These prizes are distributed at various community events.
Target Market	Residential customers and children at events
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	49	41	3	93
FEVI	0	6	9	3	18
FEW	0	0	0	0	0
Total	0	55	50	6	111

Table 10-6: Energy Champion Program

Program Description	This program develops partnerships with local sports organizations such as the Western Hockey League, BC Hockey League, Kootenay International Junior Hockey League and Vancouver Canucks to promote energy conservation to consumers. Primarily targeting families and children, the Companies have engaged with approximately 18,000 customers through a variety of methods, including online competitions, face-to-face interactions, pre and in-game activities and booth activities.					
Target Market	Residential customers, students and schools, and general public					
New vs Retrofit	Retrofit					
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research &	Total
	FEI	0	122	130	0	252
	FEVI	0	59	0	0	59
	FEW	0	0	0	0	0
	Total	0	181	130	0	311

Table 10-7: Home Efficiency Measures (new)

Program Description	This program promotes low-cost measures for customers to install at home in order to achieve energy savings. The Companies supported the Tap by Tap program to deliver water and energy savings kits to approximately 650 residential homes in the Okanagan-Similkameen region and collaborated with FortisBC Inc. to achieve cost efficiencies. The program will be complete in 2013 and will be evaluated for potential energy savings at that time.					
Target Market	Residential customers					
New vs Retrofit	Retrofit					
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	17	0	0	17
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	17	0	0	17

Table 10-8: Municipal Partnerships – Other

Program Description	This program provides support to municipal conservation programs. In Q4 2012, the Companies launched a study to identify collaborative opportunities with municipalities on energy efficiency programs.					
Target Market	Commercial customers, builders/developers and municipal employees					
New vs Retrofit	Retrofit					
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	0	0	8	8
	FEVI	0	0	0	1	1
	FEW	0	0	0	0	0
	Total	0	0	0	9	9

Table 10-9: Medium-Large Commercial Education Sessions (new)

Program Description	This program includes the development and delivery of education sessions on natural gas equipment to guide commercial building operators and facility managers in identifying prospective natural gas savings and optimizing building performance. The curriculum was developed by Natural Resources Canada (NRCan) and was delivered to over 200 attendees in 8 regions of BC. The Companies collaborated with the Climate Action Secretariat on three sessions to achieve cost efficiencies. In addition, FEI collaborated with FortisBC Inc. to deliver two NRCan 'Spot the Savings' workshops in the Okanagan and Kootenay regions.
Target Market	Commercial building operators
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	39	0	0	39
FEVI	0	9	0	0	9
FEW	0	0	0	0	0
Total	0	48	0	0	48

Table 10-10: Small Commercial Education and Outreach

Program Description	This program promotes energy efficient practices to small and medium sized commercial customers through print and online communications and events. These initiatives include bill inserts, ethnic communication materials and partnerships with Climate Smart and Small Business BC.
Target Market	Small commecial customers
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	62	6	0	68
FEVI	0	7	0	0	7
FEW	0	0	0	0	0
Total	0	69	6	0	75

Table 10-11: Commercial Trade Shows and Association Events

Program Description	This program takes advantage of industry trade shows, industry association meetings and events, building award events and partnerships such as with the Business Improvement Areas of British Columbia (BIABC) to promote energy efficiency and conservation practices to commercial customers.
Target Market	Commercial customers
New vs Retrofit	Both
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	63	13	0	76
FEVI	0	4	0	0	4
FEW	0	0	0	0	0
Total	0	67	13	0	80

Table 10-12: Behaviour Programs - Online Community Site

Program Description	This program continues to support the Health Authority Staff Engagement Pilot Program that began in 2011 through increased development of the online tool and surveying engaged employees on changes in their actions. Development of the program to extend to other health authorities and large institutional/municipal customers is in progress and will continue into 2013. This will be a particularly valuable educational tool for organizations that have committed to becoming carbon neutral under the BC Climate Action Charter.
Target Market	Commercial/municipal/institutional organizations and their employees
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	67	0	0	67
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	67	0	0	67

Table 10-13: Behaviour Programs - Energy Specialists (new)

Program Description	This program supports behaviour education programs generally delivered by Energy Specialists or other Energy Management staff in their respective organizations. Examples of these education initiatives include the University of British Columbia's 'Shut the Sash' campaign on fume hoods, and Capilano University's fleece campaign. Other initiatives include green fairs, education sessions, "green" teams and competitions.
Target Market	Commecial/municipal/institutional organizations and their employees
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	8	6	0	14
FEVI	0	3	0	0	3
FEW	0	0	0	0	0
Total	0	11	6	0	16

Table 10-14: Conservation Assistance - Education and Outreach

Program Description	This program included three initiatives in 2012: the BC Housing Tenant Engagement Program, the BC Non-Profit Housing Association annual conference and a needs assessment study for the development of a building operators best practices training program led by the BC Non-Profit Housing Association.
Target Market	Low income, residential customers
New vs Retrofit	Retrofit
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	29	0	0	29
FEVI	0	5	0	0	5
FEW	0	0	0	0	0
Total	0	34	0	0	34

Table 10-15: School Programs: Class and Online Curriculum (new)

Program Description	This program continued development from 2011 of the EEC in-class and online modules and printed collateral. This program also supports section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in schools in the Companies' service area.
Target Market	Students
New vs Retrofit	N/A
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	0	9	0	9
FEVI	0	0	4	0	4
FEW	0	0	0	0	0
Total	0	0	13	0	13

Table 10-16: School Programs: K-12 In-Class Programs and Presentations

Program Description	This program continued support for a variety of in-school and student programs such as Destination Conservation, BC Green Games, Environmental Mind Grind and the BC Lions Energy Champion Assembly presentations. New initiatives started in 2012 targeting high school students include partnerships with Green Bricks and the Vancouver Aquarium (launching in 2013). This program also supports section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in schools in the Companies' service area. The expenditures below include expenditures for the 2011-2012 and 2012-2013 school years.
Target Market	Students
New vs Retrofit	Both
Expenditures ($,000s)	2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	344	0	0	344
FEVI	0	68	0	0	68
FEW	0	0	0	0	0
Total	0	412	0	0	412

Table 10-17: School Programs: K-12 Home Efficiency Measures

Program Description	This program supports efficient low-cost fixtures distributed to students through the Beyond Recycling program, and in 2012 started distributing low flow showerheads and aerators to over 200 students to apply energy conservation concepts in the home. This program also supports section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in schools in the Companies' service area. The energy savings for this program were minimal, but should this program expand, the Companies will consider including energy savings.					
Target Market	Students and residential customers					
New vs Retrofit	N/A					
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	1	0	0	1
	FEVI	0	0	0	0	0
	FEW	0	0	0	0	0
	Total	0	1	0	0	1

Table 10-18: School Programs: Post-Secondary

Program Description	This program supported 3 initiatives targeting post-secondary institutions: Go Beyond's competition encouraging students living on campus to conserve energy; Northwest Wildlife Preservation Society's competition for students to develop an action plan focused on achieving natural gas EEC initiatives for the province; and funding support for Selkirk College's new energy management course. This program also supports section 44.1 (8) (c) of the Utilities Commission Act, R.S.B.C 1996, c.473, s.125.1 (4) (e), where a public utility's plan portfolio is adequate if it includes an education program for students enrolled in post secondary institutions schools in the Companies' service area.					
Target Market	Students					
New vs Retrofit	N/A					
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	59	37	0	96
	FEVI	0	4	3	0	7
	FEW	0	0	0	0	0
	Total	0	63	40	0	103

10.3 2012 CEO Programs Planned But Not Launched

10.3.1 COMMERCIAL MULTI FAMILY

This program includes the educational campaign for multi-family customers that would supplement the Multi Unit Residential Building ("MURB") program in the Commercial Energy Efficiency Program Area. It will be launched when the MURB program expands in 2013.

10.4 Summary

All of the initiatives described in this section were vital to promoting and educating the public on energy conservation behaviours and keeping the Companies' conservation message "top of mind" among customers in 2012. Doing so fosters a culture of conservation, which will benefit communities, increase participation in EEC incentive programs and ultimately support the shared goals of the Companies and the Provincial Government.

11 ENABLING ACTIVITIES

11.1 Overview

In 2012, Enabling Activities continued to support and supplement the Companies' EEC program development and delivery, advancing energy efficiency in British Columbia. This included the ongoing Efficiency Partners program, and work completed in advancing national, provincial and municipal building codes and appliance/equipment standards. While these Programs play a very important role in the Companies' portfolio of EEC activities by advancing the delivery of all Program Areas, the FEU have not claimed any energy savings for work completed in this area. The Companies are exploring an acceptable methodology for measuring and attributing energy efficiency savings from Codes and Standards work and will claim savings on a program-by-program basis at such time an appropriate methodology has been determined.

Enabling Activities expenditures are captured in the Residential Energy Efficiency Program Area costs in 2012 (see Section 5, Table 5.1) and are not separately included in the portfolio level results[15]. This section has been included because the Companies wish to highlight the importance of these Enabling Activities to the success of the overall EEC initiative.

The EEC team worked toward increased integration and collaboration with the FortisBC Inc. electric utility in 2012. Steps were taken toward integrating the Efficiency Partners program in the shared services territory, with a plan to integrate heat pump contractors in the Companies' directory listing of contractors in 2013. Table 11-1 summarizes the projected and actual expenditures for the Enabling Activities in 2012.

Table 11-1: 2012 Enabling Activities Results

Program and Service Territory	Annual Gas Savings (GJ/yr.)		Actual NPV Gas Savings (GJ)	Utility Expenditures ($000s)						Benefit/Cost Ratios				
				Incentives		Non-Incentives		All Spending						
	2012-2013 EEC Plan	2012 Actual		2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	2012-2013 EEC Plan	2012 Actual	TRC	MTRC	Utility	Participant	RIM
Efficiency Partners Program														
FEI	No Direct Savings			0	0	450	259	450	259	No Direct Savings				
FEVI				0	0	50	75	50	75					
Total				0	0	500	334	500	334					
Codes and Standards														
FEI	No Direct Savings			0	0	0	15	0	15	No Direct Savings				
FEVI				0	0	0	0	0	0					
Total				0	0	0	15	0	15					
ALL PROGRAMS														
FEI	**No Direct Savings**			**0**	**0**	**450**	**274**	**450**	**274**	**No Direct Savings**				
FEVI				**0**	**0**	**50**	**75**	**50**	**75**					
Total				**0**	**0**	**500**	**349**	**500**	**349**					

[15] These costs are not double counted at the portfolio level.

Notes:

- The Energy Specialist program was formerly included under Enabling Activities. In 2012 it was included under the Commercial Energy Efficiency Program Area. This reporting change reflects both the financial tracking of the program within the Commercial Program Area and the commercial nature of the Energy Specialist activities.

11.2 2012 Enabling Activities by Program

The following tables outline the specific Enabling Activities undertaken in 2012 by program, including both program and measure descriptions along with a breakdown of non-incentive spending. The success of the Residential Furnace Replacement Pilot program (see Section 5, Table 5-9), which was promoted through the contractor network, and oversubscribed in the eight-week pilot period, demonstrates the value of the Efficiency Partners Program. Communications were immediate and responsive through the network and at the end of the pilot period 73 per cent of the program's participants used contractors who were members of the Contractor program network.

Table 11-2: Efficiency Partners Program

Program Description	This program develops and manages a contractor network to promote EEC programs and energy efficiency messaging. The Companies identify efficiency partners as equipment manufacturers, service contractors, distributors and retailers, and recognize the influence these various industry groups have with the end use residential and commercial customers who make energy efficiency decisions.					
Participants	Service Region	2012 Projected	2012 Actual			
	FEI	0	0			
	FEVI	0	0			
	FEW	0	0			
	Total	0	0			
Expenditures ($,000s)	2012					
	Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
	FEI	0	91	160	7	259
	FEVI	0	13	57	4	75
	FEW	0	0	0	0	0
	Total	0	104	218	12	334

Notes:

- Approximately $151,000 of the $218,000 in communication expenditures is from contractor co-op advertising activity.
- The companies do not currently attribute energy savings directly to this program as it is difficult to quantify the impact in terms of GJ savings.

Table 11-3: Codes and Standards

Program Description	Utilities have a unique understanding of energy supply and customer demand cycles, which can be of assistance in the development of codes and standards. The content and timing of code implementation directly affects market transformation in all program areas. The Companies' level of regulatory involvement typically includes one of three involvement classifications: monitoring, stakeholder engagement and developing regulations. The initiatives below outline current projects and levels of involvement with a variety of codes and standards activities.
Public consultation process	Evaluation and analysis of National, Provincial and City of Vancouver initiatives for energy efficiency. Development of appropriate responses to these initiatives within specified timelines.
Industry consultation process	Collaboration with entities like BC Hydro and the Home Owner Protection Office (HPO) for the development of industry training and guidelines on implementation of new energy efficiency measures. Participation with the BC Safety Authority Gas Technology Committee industry stakeholder group.
Involvement with supporting projects	Active participation for supporting projects like: the RDH Engineering Group's Measured Energy Savings Attributable to Deep Retrofits of High-Rise Residential Buildings (which is demonstrating energy efficient retrofits for Multi-Unit Residential Buildings) and the Morrison Hershfield Engineering study of Thermal Performance of Building Envelope Assemblies for Buildings in BC (which is helping to identify which wall assemblies are most cost and energy effective).
Codes and Standards Strategy	Active participation on the Candian Standards Association (CSA) Strategic Steering Committee on Fuel Burning Equipment. This committee is the highest committee in the fuel sector at CSA and oversees all committees and sub-committees in the fuel burning sector.
Codes and Standards Maintainance	Active participation on the CSA Technical Committee on Energy efficiency and Related Performance of Fuel-Burning Appliances and Equipment. This committee oversees all of the eleven existing performance standards for gas-fired equipment and is looking to develop new needed standards for equipment that are wanted or needed by industry.
Thermal Metering	The CSA C-900 Canadian Heat Meter Standard has now been developed and is in the final review process. A stakeholder group has been created and is working through the final remaining issues to open up this opportunity for energy measurement and savings.
Internal awareness of Code and Regulatory changes	Development of internal documents and updates for relevant program areas and personnel.
Standards library	Purchase of up to date standards for reference.

Participants

Service Region	2012 Projected	2012 Actual
FEI	0	0
FEVI	0	0
FEW	0	0
Total	0	0

Expenditures ($,000s)

2012

Service Region	Incentives	Admin	Communication	Research & Evaluation	Total
FEI	0	15	0	0	15
FEVI	0	0	0	0	0
FEW	0	0	0	0	0
Total	0	15	0	0	15

11.3 Summary

Enabling Activities are critical initiatives that support the advancement of energy efficiency for a variety of EEC Program Area activities. In 2012, the Efficiency Partners Program experienced a 40 percent increase in the number of Contractor program members over 2011, bringing the number of applicants in the network to 483. As the program continues to expand, so too does the number of contractors available to support the delivery of EEC programs. The Companies' involvement in Codes and Standards work in 2012 encompassed varying degrees of activities including monitoring, analyzing and responding to existing and proposed regulatory changes and direct participation in energy efficiency pilot projects that enable program development, market transformation, and the early adoption of energy efficiency Regulations.

12 EVALUATION

The FEU have advanced their evaluation activities significantly in 2012, in keeping with the expectation that as program activity has ramped up and more programs are put into market, an increase in evaluation activity will follow. This section outlines the evaluation initiatives and activities undertaken in 2012.

12.1 EM&V Framework

The FEU developed an EM&V Framework in 2012 to formalize the background, objectives, principles and general practices that guide the Companies' approach, resources and timeframes for EM&V activities. The framework addresses the following Commission directive from the April 2012-2013 RRA Decision.

> *"The Commission Panel sees benefit in the establishment of an EM&V Framework. The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework."*

The draft EM&V Framework was presented to the EECAG at the fall 2012 workshop (see Section 4). The Companies have plans to finalize the EM&V Framework in 2013, taking into consideration feedback received from the EECAG and our evaluation partners. The EM&V Framework will be updated periodically to meet new industry standards and best practices. While it is currently in draft form, the Companies have adopted the Framework in so far as it is developed and do review any new evaluation activities and planning to ensure they are aligning with it.

12.2 2012 Program Evaluation and Evaluation Research Activities

Many EEC programs reached maturity in 2012, resulting in increased evaluation activities[16]. The evaluation activities conducted were focused on identifying energy savings, assessing participant awareness, satisfaction and education, and research. In order to present and acknowledge this increase, the summary of all program evaluation and evaluation research related activities will be presented in two separate tables.

[16] Types of evaluations include: Communications, which focus on advertising and media outreach; Process, where surveys and interviews are used to assess customer satisfaction and program success; Impact, to measure the achieved energy savings attributable from the program; and Measurement & Verification, to monitor real time energy savings associated with energy conservation measures.

Table 12-1 contains an inventory of all program evaluation and evaluation research related activities undertaken in 2012. Table 12-2 contains an inventory of all program evaluation studies completed in 2012, including a brief description of the Methodologies and Key Findings. Expenditures for activities presented in Table 12.1 have been reported within the applicable Program Area administrative costs, but are also reported here in order to provide a concise, easy-to-view summary of evaluation activities. Included in the table are a list of all the 2012 evaluation activities; the Program Area each activity occurred in; the general type of evaluation activity undertaken; the Companies' actual 2012 expenditures; and a status update on each activity. The total expenditures for program evaluation and research activities in 2012 were $469,000.

Table 12-1: Inventory of EEC Program Evaluation and Evaluation Research Activities Conducted in 2012

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status
EEC/PowerSense Ad Tracking 2012	EEC Portfolio	Communication	ongoing	none	$37	Tracking EEC and Advertising awareness Phase 1: **Completed December 2012.** Phase 2: **Expected completion April 2013**
EEC Collaboration with Municipalities	EEC Portfolio	Communication	new	none	$8	In progress. **Expected completion March 2013**
Evaluation, Measurement & Verification Framework	EEC Portfolio	N/A	N/A	none	$4	Habart & Associates assisted in the initial development of the EM&V Framework.
TLC Furnace/Fireplace 2011	Residential	Process	3	none	$14	Participant Survey - **Completed February 2012 by Sentis**
TLC Furnace/Fireplace 2012	Residential	Process	3	none	$0	Participant Survey - to be completed **Spring 2013 by TNS**
New Construction Program - Non - Energy Benefit Analysis	Residential	Process	0	BCHydro	$13	Residential New Construction Non-Energy Benefits - **Completed February 2012 by Dunsky Energy Consulting in collaboration with Research Into Action.** Cost incurred in 2011
Furnace Replacement Pilot Program	Residential	Process	New	none	$14	Customer satisfaction survey collection - **Expected completion February 2013 by IPSOS. Analysis of results to be completed March 2013.**
Furnace Replacement Pilot Program: Phase 2	Residential	Process	New	none	$0	Survey questionnaire in design stage - **Expected completion March 2013 by TNS.** **Quality Installation Study for Furnaces :** RFP stage **Estimation of Remaining Life on Replaced Furnaces in Furnace Replacement Pilot Program:** Design stage
LiveSmart BC program evaluation	Joint Initiatives	Impact & Process	4.5	BCHydro, FEU, FBC and MEM	$50	Preliminary Report completed Fall 2012. **Final Report to be completed in 2013**. Results will guide savings estimates reported for LiveSmartBC and 2013 program launch offering.
Switch N Shrink	High Carbon Fuel Switching (Residential)	Impact & Process	3	none	$27	Switch 'N Shrink Program Evaluation Survey Summary Report - **Completed December 2012 by Insights West.**
Energy Savings Kits (ESK)	Conservation for Affordable Housing	Process	2	BC Hydro	$0	Small in-house customer satisfaction survey conducted by FortisBC in 2012. Program savings refer to the in-depth customer survey performed by BCHydro in 2010 and savings assumptions from the latest CPR figures.

Table 12-1: Inventory of EEC Program Evaluation and Evaluation Research Activities Conducted in 2012 (continued)

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status
Energy Specialist Pilot Program Energy Savings Audit	Commercial (Enabling Activities)	Impact	2	none	$26	Energy Specialist Program - Energy Savings Audit - Preliminary Results completed January 2013 include verified project savings. **Final Report to be completed by March 2013 by Prism Engineering Ltd and ClearLead Consulting Ltd.**
Efficient Boiler Program (Retrofit)	Commercial	Impact & Process	9	none	$66	Analysis of Energy Savings from FortisBC Efficient Boiler Program (EBP) - Preliminary results completed December 2012. **Final Report to be completed Q2 2013 by Prism Engineering Ltd. Further analysis to be conducted in 2013.**
Fireplace Timers Pilot Project	Commercial	Impact & Process	1	none	$10	Analysis of Energy Savings from FortisBC Fireplace Timer Pilot Project - Preliminary results completed September 2012. **Final Report to be completed Q2 2013 by Prism Engineering Ltd. Further analysis to be conducted in 2013.**
Efficient Commercial Water Heater Program - Metering project	Commercial	Impact	2.5	none	$6	Metered pre and post implementation natural gas consumption to validate savings assumptions. Monitoring results expected to be completed by **March 2013**
Radiant Tube Heater Pilot Program	Commercial	Impact	2	none	$1	Metered pre and post implementation natural gas consumption to validate savings assumptions Data Collection completed February 2012. **Summary of results to be completed Q2 of 2013.**
City of Vancouver Residential Solar Water Heating Pilot	Innovative Technologies	Measurement & Verification	2	City of Vancouver & Solar BC	-$6	Received 20K contribution from COV towards M&V of the project which reduced costs for FortisBC. 4 sites under monitoring for minimum 12 months. Expected completion of **M&V + Final Report by October 2013**.
City of Courtenay Pool Heating Demonstration Project	Innovative Technologies	Measurement & Verification	2	City of Courtenay	$16	Expected completion of **M&V + Final Report by November 2013.**
PSECA Solar	Innovative Technologies	Measurement & Verification	3	Ministry of Energy Mining (PSECA)	$0	Post consumption analysis to be completed in **2013**
Occupancy Sensor Ventilation Control Pilot	Innovative Technologies	Measurement & Verification	2	School District (Burnaby & North Delta)	$0	4 schools under monitoring for a minimum 12 months. Previously anticipated completion by late 2012. Due to delay in monitoring installation completion of **M&V + Final Report is expected to be June 2013.**

Table 12-1: Inventory of EEC Program Evaluation and Evaluation Research Activities Conducted in 2012 (continued)

Evaluation Name	Program Area	Type of Evaluation	Years the program has been running	Evaluation Partnership	Actual Evaluation Expenditure (000's)	Evaluation Status
AHU Coil Cleaning Pilot	Innovative Technologies	Measurement & Verification	1	Vancouver Island Health Authority	$5	Expected completion of **M&V + Final Report by February 2014.**
0.80 Pilot	Innovative Technologies	Measurement & Verification	2	Canadian Gas Association, Natural Gas Technology Centre & other utilities	$96	Expected completion of **M&V + Final Report by Q1, 2014.**
0.67 Pilot	Innovative Technologies	Measurement & Verification	1	none	$50	Expected completion of **M&V + Final Report by July 2014**.
COV MURB Pilot	Innovative Technologies	Measurement & Verification	new	City of Vancouver	$0	Pending further pilot design details. Also referred to as the 'Condo Retrofit Pilot'
Technology Retrofit Program	Industrial	Measurement & Verification	1	none	$15	M&V Plan developed and awaiting commissioning.
Event Tracking 2011	Conservation Education and Outreach	Communication	6	none	$6	Participant Awareness - **Completed April 2012 by IPSOS**
Contractor Program Research 2011	Efficiency Partners Program	Process	2	none	$4	Contractor Participation Research - **Completed February 2012 by Participant Research.** $4,175 paid in 2011 and remainder in 2012. Total fees for this project were $8350.
Contractor Program Co-ops Ads Research Project	Efficiency Partners Program	Process	2	none	$7	Interviewing stage. **Expected completion February 2013**

Table 12-2 contains a summary of all program evaluation studies completed in 2012 and includes a brief description of the Methodologies and Key Findings.

Table 12-2: Inventory of EEC Program Evaluation Studies Completed in 2012

Evaluation Name	Program Area	Type of Evaluation	Methodology	Key Findings
EEC/PowerSense Ad Tracking 2012	EEC Portfolio	Communication	Online Panel	**Results from Phase 1:** 2 effective communications channels: - Bill inserts and TV ads are said to be the most engaging, informative and memorable platforms for reaching residents. - Utility websites, friends & family, hardware stores and newspapers are also effective communication channels. Since FortisBC's EEC programs are not well known, communication recall levels are low for these programs. There is confusion among the public over who sponsored the communications. There are many individually-promoted FortisBC EEC programs in the market. This has resulted in low awareness of each program, compared to the most recognized program in the province – PowerSmart (BC Hydro). **Outcome from Key Findings:** Continued with bill inserts and increased communications about residential programs in local community newspapers in Fall 2012. Implemented a Consolidated Fall Campaign that covered multiple concurrent programs, rather than running individual program communications plans.
TLC Furnace/Fireplace 2011	Residential	Process	406 telephone interviews were completed between January 20 and 24, 2012 with FortisBC customers who participated in the 2011 program. The interviewing was distributed by region and by appliances serviced to ensure representativeness of all participants in the program.	Results from 488 participants: The $25 gift card incentive was useful. 4 in 10 participants (42%) indicate that it positively influenced their decision to get their furnace and/or fireplace serviced. For participants, the perceived main benefits of annual appliance servicing are peace of mind/safety and improved efficiency. Program evaluation determined that 16% of participants identified leaks and other safety hazards from the heating systems serviced. Contractors made recommendations to 11% of the participants to either upgrade or replace their gas appliance to a higher efficiency model. 3% were in compliance. **Outcome from Key Findings:** promoting the Furnace Replacement Pilot Program with the TLC Program to encourage contractors to leverage on the relatively easy-to-access TLC program to promote furnace upgrade. The Companies will be starting an installatino quality inspection study on furnaces to quantify and verify leaks and other safety hazards.

Table 12-2: Inventory of EEC Program Evaluation Studies Completed in 2012 (continued)

Evaluation Name	Program Area	Type of Evaluation	Methodology	Key Findings
New Construction Program - Non - Energy Benefit Analysis	Residential	Process & Impact	Quantify the 'non-energy benefits' consumers enjoy due to the energy efficiency programs implemented. Combination of secondary research in other jurisdictions and primary research in BC to quantify dollar value of non-energy benefits. The NEB analysis was based on a conservative approach using published studies in 5 jusrisdications.	The results of the study indicated that the non-energy benefits are significant, ranging from 15% to 361% higher than the 'energy' benefits when calculating the TRC. This suggests that the 15% for NEB attributed using the MTRC pursuant to the BC DSM Regulation may be underestimating these benefits. Due to small sample size, results were used as directional measures. **Outcome from Key Findings:** The results confirms more research is required before the results can be applied to the design of the New Homes Program.
Switch N Shrink	High Carbon Fuel Switching (Residential)	Impact & Process	**Survey:** online/mail survey conducted on a sample size of 369 program participants. **Technical:** Gas consumption compared to oil bills.	A sample size of 369 program participants surveyed indicated they were extremely satisfied with the Switch N' Shrink Program (score of 8.6 on a 10-point scale). Program received a very strong Net Promoter score of 62. The participants that were surveyed are also very likely to recommend the program to friends and family (8.9 out of 10). The lower energy bills and the $1,000 rebate are the key drivers of program participation. Study showed a median annual cost savings of $139 per year and the average percentage cost savings from switching from heating oil to natural gas was 16%. (Results were based on 14 participants with 12 continuous months of heating oil and natural gas cost data) Annual energy savings were 4.63 gj per year. Energy savings results were considered directional only due to the small sample size. **Outcome from Key Findings:** Introduced a contractor incentive as contractors were the key to promoting the program. Extended the program by another year due to program's success.
Energy Savings Kits (ESK)	Conservation for Affordable Housing	Process	Small in-house customer survey conducted by CRM to measure customer satisfaction.	36 participants were surveyed and results showed a high level of customer program satisfaction. A score of 9.4 on a scale out of 10. **Outcome from Key Findings:** No change required to the program due to the high level of customer program satisfaction.
Efficient Boiler Program (Retrofit)	Commercial	Impact & Process	Participant survey and consumption analysis were conducted for a sample size of 239 Commercial participants.	Preliminary results from the sample size showed an average savings of 19.3%. **Outcome from Key Findings:** Conduct further analysis and include a larger sample size to verify savings. Calculate an annual rate of savings (GJ) per year for the program. Conduct follow-up phone calls to further analyze outliers.

Table 12-2: Inventory of EEC Program Evaluation Studies Completed in 2012 (continued)

Evaluation Name	Program Area	Type of Evaluation	Methodology	Key Findings
Fireplace Timers Pilot Project	Commercial	Impact & Process	Participant survey and consumption analysis were conducted for all 8 Multi-Unit Residential Building locations with 384 timers installed.	Preliminary results: average annual natural gas savings of 4.1 GJ for each timer installed. **Outcome from Key Findings:** Conduct further analysis on outliers and verification of savings. Conduct analysis to investigate fuel substitution due to participants increasing usage of their electric baseboard heating.
Energy Specialist Pilot Program Energy Savings Audit	Commercial (Enabling Activities)	Impact	A total of 35 projects were reviewed by Prism Engineering Ltd and ClearLead Consulting Ltd. Each Energy Specialist was required to complete project specific questionnaire, and provide detail project calculations and information for review. Project savings were verified on a project by project basis. Energy Specialist gas savings projects verified were those that did not take advantage of an existing Fortis BC incentive program.	Results from 29 completed projects were reviewed to represent savings in 2011 and 2012. 6 projects are still ongoing and therefore excluded from the 2011/2012 findings. In 2012, 12 projects were completed and evaluated. Results indicated 1,081 GJ annual savings & 4,713 GJ of NPV Gas Savings. In 2011, 17 projects were completed and evaluated. Results indicated 8,742 GJ annual savings & 24,943 GJ of NPV Gas Savings. **Outcome from Key Findings:** Update and revise the Energy Specialist training to provide a structured approach on how to document the research, estimate the energy savings, and provide overall targets to achieve.
Event Tracking 2011	Conservation Education and Outreach	Communication	On-site intercept interviews were conducted during various events targeted for this study, using interviewer administered surveys completed on paper.	FortisBC's participation in public and community events in 2011 has encouraged energy conservation. To consolidate these effects, FortisBC needs to sustain its participation in public and community activities over a longer period of time. The positive effects of participating in these events was limited by fairly low awareness of the company's involvement in them. To reach a broader base of event participants with its EEC communications, FortisBC needs to increase promotion of its participation in community and public events prior to the events or enhance its visibility at them. **Outcome from Key Findings:** Increase effort on cross promoting events through the use of social media channels. Redesign of the event booths to create a stronger presence on site.
Contractor Program Research 2011	Efficiency Partners Program	Process	Participant Research conducted 20 interviews with natural gas contractors representing all FortisBC regions, including participants and non-participants in the FortisBC Contractor Program.	Contractors generally acknowledge Program participation offers many benefits however, research suggests that many contractors postponed or failed to complete the necessary application forms, perceiving the process to be too time-consuming. Many responses underscore that the enrollment process must be effortless. Overall program marketing could benefit from improvements that increase contractor interest and participation. **Outcome from Key Findings**: Contractor forms and applications were revised to allow for easier completion.

12.3 Summary

Evaluation is an integral part of DSM planning and implementation. Early consideration of evaluation requirements helps to ensure that the necessary data is collected throughout the program development and implementation process. The companies have significantly increased the amount of evaluation activities completed and initiated in 2012 over previous years and continue to be diligent in ensuring industry standards are met in the evaluation of EEC programs. The EM&V Framework provides valuable information relating to the types of evaluation activities that should be conducted and when, approaches for managing evaluation studies and the implementation of industry standards for evaluation work.

13 DATA GATHERING, REPORTING AND INTERNAL CONTROLS PROCESSES

13.1 Overview

The following section demonstrates that the Companies have business practices in place to ensure EEC activities and associated spending are in compliance with the Commission Orders and the internal control processes of the Companies in general. In its EEC Decision, the Commission directed the Companies to include a discussion in the EEC Annual Report of the Companies' internal data gathering, monitoring and reporting control practices. This section addresses that directive by providing general information on data gathering and on the Companies' business practices related to program development and application processing.

13.2 Program Tracking, Evaluation and Reporting Functions

The 2011 Annual Report (Section 14) described the way in which the companies had separated the EEC tracking, evaluation and reporting functions from the group responsible for program development and implementation. While the Companies believe they have been effective in conducting these activities throughout the history of its EEC programming, the following benefits of and accomplishments by the tracking, evaluation and reporting group have been achieved in 2012, the first full year of separation of tracking, evaluation and reporting:

Reduction of regulatory burden on Program Managers and other program staff, allowing increased productivity in the development and delivery of programs,

- Implementation of and improvements to the new EEC tracking software system,
- Improvements to the planning and implementation of evaluation, measurement and verification activities,
- Improvements in the oversight of and support to program staff in the review and identification of measure savings information and calculation of cost/benefit values,
- Improvements to annual reporting activities and other special reporting requirements as necessary from time to time, and
- Improvements to EEC Advisory Group engagement activities (see Section 4).

13.3 Robust Business Case Process Applied to All Programs

Before a new EEC pilot or program can be implemented, a business case must first be developed. The Companies are committed to putting each pilot or program through the appropriate level of internal scrutiny before moving ahead, and believe doing so ensures an increased chance of pilot or program effectiveness.

Business cases include information about program rationale and purpose, as well as a description of the target audience, assumptions, cost-benefit tests and proposed evaluation methods. Cost-benefit analysis is performed using the California Standard Tests ("CST") as outlined in the California Standard Practice Manual. The Companies use an in-house cost-benefit modeling tool developed in partnership with expert industry consultants[17] to provide the following areas of analysis:

- Benefits incurred over measure life of the individual programs, including energy savings;
- Total costs incurred in implementing the program, including administrative, incentive, marketing and evaluation;
- The four CST tests (Rate Impact Measure ["RIM"], Utility, Participant, and TRC); and
- The MTRC in accordance with British Columbia Demand-Side Measures Regulation.

The results from this modelling are used as inputs for the business cases, which are approved in accordance with the Companies' policy on financial authorization levels. In the future, this cost-benefit modelling will be accomplished within the Companies' DSM tracking system.

13.4 Incentive Applications Vetted for Compliance with Program Requirements

Ensuring that all customer applications are compliant with program eligibility requirements as laid out in program terms and conditions is also part of the internal control process. The Companies have a number of mechanisms in place to ensure EEC incentive funding applications are in compliance with program requirements. The verification process is specific to each program and is dependent on the type of program, its complexity, the financial value of the incentive and other parameters. The general principles applied are as follows:

- Each application is reviewed for completeness and accuracy;
- Applications must meet the criteria outlined in the terms and conditions of the program put forward through the approval process;
- Once approved, incentives are distributed to participants; and
- Copies of application and supporting documents are filed and stored for seven years in case of an audit.

13.5 Internal Audit Services

The EEC team engaged the Companies' own Internal Audit Services ("IAS") group to review the internal controls associated with the EEC initiative. An IAS review of 2012 EEC activities was again conducted with the finding that EEC management processes and controls are designed and operating effectively. A copy of the 2012 IAS review summary is included in Appendix B.

[17] Willis Energy Services Ltd. and The Cadmus Group Inc. provided input into this in-house cost-benefit model.

IAS is also conducting a review of the DSM tracking system to ensure that the necessary controls are in place. This audit will include a review of the tool's design once the testing phase has been completed and a post implementation review to ensure that such controls are working properly.

13.6 Summary

The Companies are committed to strong internal controls in all aspects of the EEC program. As demonstrated in this section, the Companies' business practices related to program development, application processing and ongoing monitoring are all sound and subject to continuous improvement.

14 2012 EEC ANNUAL REPORT SUMMARY

2012 was a successful year for the FEU's EEC Programming. Both energy savings and incentives to customers have been cost effectively increased to new levels within the spending limits approved by the Commission, and in accordance with the BC Demand-Side Measures Regulation. The availability and effectiveness of program expenditures were expanded in all Program Areas and evaluation activities were diligently increased to monitor the effectiveness of EEC programming through this growth period. The Companies believe that they have made every reasonable effort to ensure EEC programs are universally available and meet provincial requirements for adequacy. The Companies also continue to implement good internal data gathering, monitoring and reporting control practices.

Appendix A

BC HYDRO AND FORTISBC MOU REPORT EXECUTIVE SUMMARY

Working in partnership:
The FortisBC and BC Hydro collaboration

Executive summary

Introduction
Led by the Ministry of Energy, Mines and Natural Gas (formerly the Ministry of Energy, Mines & Petroleum Resources), the *BC Partnership for Energy Conservation and Efficiency* was created in 2007 to support public utilities in pursuing cost-effective and competitive demand side energy management (DSM) opportunities. The express goal: to ensure "a coordinated approach to conservation and efficiency is actively pursued in British Columbia." In response to this initiative, BC Hydro and the FortisBC Energy Utilities (FortisBC) entered into a voluntary Memorandum of Understanding (MOU) to develop enhanced utility integration in support of government legislation, policy and direction. The MOU, which was executed in July 2009 and concluded on July 2012, provided shared objectives, areas of focus, guiding principles and administrative guidance. A new agreement has been established for another three years (2012 – 2015) under the same principles and objectives. This report summarizes key accomplishments achieved during the timeframe of the 2009 – 2012 MOU agreement[1].

Overview
FortisBC and BC Hydro (the "utility partners") share many of the same customers. They know that customers view their energy demands holistically, and that it makes sense to address energy efficiency and conservation for natural gas and for electricity in a coordinated fashion. By combining their skills, resources and DSM experience, the utility partners are improving the delivery of dual-fuel DSM programs that are helping customers manage their energy consumption and energy costs while meeting the goals of government.

The shared objectives as listed in the MOU were to**:**

- reduce overall energy consumption and net greenhouse gas (GHG) emissions intensities
- coordinate each party's efforts in support of the B.C. Government's goals
- provide the most cost-effective DSM programs on behalf of customers and ratepayers, while maintaining distinct and well-regarded brand identities
- reduce customer and marketplace confusion
- share knowledge and research findings

[1] Note that for the purposes of this report the time period examined was July 2009 to August 2012 as the second MOU agreement was not signed until late-August 2012.

To meet the intent of the MOU, a Project Charter was created to structure the desired outcomes, including how they would be achieved. The Charter established the necessary and appropriate organizational and management structure, including:

- a communications protocol
- a reporting system and issue resolution process
- guidance to determine project prioritization, work planning and resource allocations
- a process for creating work groups, deliverables, milestones and outcomes
- a framework on how outcomes will be achieved
- a process for entering into binding Collaborative Agreements
- clarification on confidentiality

Management structure[2]

Executive sponsorship committee (responsible for overall governance of MOU; provides leadership and vision)

Project steering group (executes the Charter within the framework and guidance of the MOU, ensures projects are in compliance with legislation, assigns resources and budgets, defines success for the projects through the definition of desired outcomes and success metrics, establishes areas of priority, resolves issues, prepares updates, approves communications plans/activities)

Project management office (coordinates and facilitates the smooth operation of the Working Groups and reports on progress of deliverables and key metrics)

Initiative working groups (delivers the desired outcomes and business objectives within framework of MOU and Charter, develops Task Plans and reporting methods, offers advice, produces deliverables, delivers projects to completion, defines cost sharing arrangement)

[2] Formed with equal representation from FortisBC and BC Hydro.

A criteria of decision-making principles was developed to determine which projects would be undertaken by the utility partners. These criteria included:

- impacted sectors
- required resources
- desired outcomes
- potential incremental DSM (natural gas, electricity and participation/uptake)
- projected efficiencies (speed to market impacts, cost-sharing potential, cost reduction/efficiencies potential)
- risk determination
- timescale
- fit with BC Hydro and FortisBC strategic priorities

Based on these decision-making principles, BC Hydro and FortisBC selected their collaborative projects. Twelve of these projects undertook significant preparatory work and/or made it to market during the first MOU period. The projects were as follows:

- Energy Saving Kits
- Residential Energy and Efficiency Works (REnEW)
- Energy Conservation Assistance Program (ECAP)
- On-Bill Financing Pilot
- Appliance Rebate Program (clothes washers)
- LiveSmart BC
- Residential New Home Program
- Continuous Optimization Program
- Public Sector Energy Conservation Agreement (PSECA)
- Commercial New Construction
- Energy Specialist Pilot Program
- Industrial Collaboration Initiatives

Summary of results

To date, these collaborative projects have been extremely successful in generating cost savings for the utility partners. (Project objectives, outcomes and benefits are detailed further in this report.) In fact, by joining forces and sharing skills and resources (e.g., marketing, communications, joint studies, consultation) the utility partners have saved approximately $1,920,000 in shared incremental costs as a result of collaborative efforts. Overall, this represents about five per cent in total cost savings as a result of the program collaborations. This figure, however, does not reflect additional savings in the form of better customer reach and more streamlined programs. Additionally, this figure does not include projects that were only recently launched, since total cost savings are not yet available. For instance, cost savings for the Residential New Home Program are not indicated in the table below, but the utility partners anticipate future cost savings of $100,000 to $125,000 per year.

To determine incremental cost savings as a result of the partnership, project leads were asked to provide conservative estimates. Only dollars that clearly would have been spent in absence of a partnership were captured under these estimates. The methodology utilized for each program collaboration increment cost saving reported can be found in the respective program collaboration profiles in this report.

Overall energy savings attributable to these programs have also been substantial. Since the beginning of each program's collaborative efforts, it is estimated the utility partners have saved 40.35 GWh[3] in electricity and 292,635 GJ[4] in natural gas under these programs. This is equivalent to the annual electricity consumption of over 3,600[5] BC homes and the annual natural gas consumption of over 3,300[6] BC homes respectively. Note that these energy savings are estimates, and have been provided to illustrate the scope/scale of the overall collaboration. These figures represent total energy savings and do not represent incremental savings as a result of the partnership. Incremental energy savings as a result of collaborative efforts could not be determined as sufficient evaluation, measurement and verification (EM&V) protocols were not set up in time to undertake this analysis. However, as noted further in this report, the intent is for BC Hydro and FortisBC to set up EM&V protocols moving forward that should hopefully enable the utilities to accurately track incremental cost and energy savings as a result of collaborative efforts.

Collaboration snapshot

The following table summarizes total program costs, energy savings and incremental costs savings incurred over the period of the collaboration.

Project/Program	BC Hydro Total Program Costs	FortisBC Total Program Costs	Energy Savings		Total Program Costs	Total Incremental Cost Savings As a Result of Collaboration	% Cost Savings As a Result of Collaboration
			GWh Savings	GJ Savings			
Energy Saving Kits	$2,500,000	$751,000	6.53 GWh	63,600 GJ	$3,251,000	$550,000	14%
On-Bill Financing Pilot	$128,000	$114,000	n/a	n/a	$242,000	n/a	n/a
REnEW	$254,000	$375,000	n/a	n/a	$629,000	$250,000	28%
ECAP	$509,000	$487,000	n/a	n/a	$996,000	$250,000	20%
Appliance Rebate Program (clothes washers)	$3,200,000	$598,000	2.5 GWh	15,000 GJ	$3,798,000	$100,000	3%
LiveSmart BC	$5,400,000	$3,526,000	5.62 GWh	174,035 GJ	$8,926,000	$380,000	4%
Residential New Home Program	$1,340,000	$74,000	n/a	n/a	$1,414,000	n/a	n/a
Continuous Optimization Program	$898,000	$31,000	n/a	n/a	$929,000	$80,000	8%
PSECA	n/a	$1,094,000	25.7 GWh	40,000 GJ	$1,094,000	n/a	n/a
Commercial New Construction	$5,100,000	$266,000	n/a	n/a	$5,366,000	$210,000	4%
Energy Specialist Pilot Program	$5,700,000	$1,721,000	n/a	n/a	$7,421,000	$100,000	1%
Industrial Collaboration Initiatives	n/a	n/a	n/a	n/a	$0	n/a	n/a
TOTAL	**$25,029,000**	**$9,037,000**	**40.35 GWh**	**292,635 GJ**	**$34,066,000**	**$1,920,000**	**5%**

The following are the key qualitative benefits that were realized from the collaboration:

- streamlined application process for customers
- extended program reach
- consistent and unified messaging resulting in improved energy literacy

[3] Net cumulative run rate effective the determined start date of collaboration. 1 GWh is equal to 1,000,000 kWh.
[4] Net annual natural gas savings.
[5] Assumes that the average BC single-family home uses 11,000 KWh/year.
[6] Average FortisBC residential customer consumption in 2012 was 87.7 GJ.

Next steps

This 2009-2012 MOU has been a successful pilot in the joint delivery of DSM projects/programs and the utility partners have identified key lessons and future opportunities for improvement. The utility partners are currently working on creating consistent key performance indicators (KPIs). The need for a formalized evaluation strategy has been identified as a priority, going forward. Having a strategy in place to capture measurable outcomes of the collaboration will better enable future reporting, evaluation and screening, and will also allow a greater understanding of the incremental benefits. Both utility partners are currently engaging their respective evaluation teams to develop a plan to quantify the deliverables of our partnership, and are working cooperatively to identify a consistent, shared approach. The plan is expected to be developed by April 2013.

Additional lessons have been learned from these joint projects, which will be used to gain greater efficiency and effectiveness with future collaborations. Key lessons learned were as follows:

- Streamlined customer process offers great benefit and should continue to be a priority.
- Reporting alignment can be challenging, as the two utility partners have different fiscal periods.
- Planning for programs and incentive funding has been complicated by differences in the timing of utility funding cycles (e.g. business case and regulatory timelines).
- There are delays/challenges associated with contracts/agreements (e.g. the need to establish a simplified contract process has been identified).
- There is a need to clearly define co-branding rules for new joint initiatives (underway).

Lessons learned are elaborated on within the individual project profiles in this report.

Appendix B

INTERNAL AUDIT SERVICES
2012 EEC REVIEW REPORT

FORTIS BC™

FortisBC Energy
Internal Audit Report

Date: June 30, 2012

To: Doug Stout, Vice President, Energy Solutions and External Relations

CC: Sarah Smith, Senior Manager, Energy Efficiency and Conservation
David Bennett, Vice President, General Counsel and Corporate Secretary

From: Terry McMillan, Director, Internal Audit

Re: **Energy Efficiency & Conservation Program – Internal Control and Process Review**

INTRODUCTION

The Energy Efficiency and Conservation Program ("The Program" or "EEC") is designed to provide customers with tools and incentives to manage their natural gas consumption, reduce their energy costs, and lower their greenhouse gas emissions.

In April 2009, the British Columbia Utilities Commission ("BCUC") granted approval for the Program expenditure of $41.5 million. The Program includes rebates and incentives on a number of energy efficient appliances, equipment and systems as well as education and outreach initiatives to increase awareness of the energy efficiency and environmental benefits that can be achieved by using clean burning natural gas in high efficiency appliances.

SCOPE AND OBJECTIVES

An Internal Audit of the EEC Program was completed in the first quarter of 2011. This is a follow up to that project as requested by management.

The objective of the review was to evaluate the design and operating effectiveness of the EEC project management processes and controls as established for the facilitation of the Program using the following criteria:

- Identify key risks and determine whether risks are appropriately managed;
- Review existing policies, procedures and practices with reference to best practices;
- Review the level of adherence to and compliance with existing policies and procedures;
- Develop recommendations and potential action plans to address any significant issues or opportunities for improvement that may be identified;
- Review for compliance with the BCUC Decision regarding EEC.

OBSERVATIONS

Policies and procedures are in place to ensure timely monitoring of program effectiveness in all program areas by management; however, Internal Audit has identified some recommendations for minor improvements regarding internal program administration as shown in the attached summary.

CONCLUSION

Based on our review, we have concluded that the EEC project management processes and controls are designed and operating effectively. The project is operating in compliance with the BCUC decision.

Observations and Recommendations

#	Observations	Risk	Recommendations	Management Response
1.	**Internal Program Administration** A review of various programs and related applications resulted in the following exceptions: The following programs had a number of duplicate payments to customers after additional testing by IA. a) TLC Gift Cards for Fireplaces & Furnaces – 26 duplicates ($1,300) IA did not find any evidence of more than two applications for any customer or premise from over 25,000 applications. b) Energy Efficient Water Heater Program – confirmed only two duplicate payments ($200) from over 3,400 applications c) Enerchoice Fire Place Program – 2 duplicate payments ($600) from over 1,700 applications	Ineffective application evaluation process can result in two or more payments to customers.	a) Adherence to program terms and conditions should be monitored. b) Process improvements should be implemented to verify/confirm if an application has been previously processed and paid.	**Management Response:** Incentive payments for these programs are administered by a third party fulfillment house. The implementation of FEI's tracking system, TrakSmart, should eliminate any need for manual duplicate checking on the spreadsheets currently being used by the fulfillment house. TrakSmart is expected to be fully implemented by Q3 2012. **Management Accountability:** Sarah Smith, Senior Manager, EEC Beth Ringdahl, EEC Program Manager (Residential) **Estimated Timing:** Q3 2012

Observations and Recommendations

#	Observations	Risk	Recommendations	Management Response
2.	**Contract Renewal** One contract (Energy Savings Kit) with BC Hydro has expired and there is no evidence that either party had agreed to continue in writing as per the terms of the contract.	No active contract in place covering Third Party services.	Management should develop a process to track active contracts for renewal.	**Management Response** Currently in progress to extend contract. **Management Accountability:** Ned Georgy, EEC Program Manager (Affordable Housing) **Estimated Timing:** September 2012.

Attachment I3

FEI/FEVI/FEW AMORTIZATION PERIOD ANALYSIS

FEI Summary of Rate Impacts

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative Delivery Rate Impact Compared to 2013 Approved																				
Scenario 1: Expensing EEC Expenditures	15.91%	4.29%	4.20%	4.16%	4.28%	4.30%	4.33%	4.35%	4.37%	4.39%	4.41%	4.43%	4.45%	4.47%	4.49%	4.51%	4.53%	4.54%	4.56%	4.58%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.95%	3.10%	4.23%	5.25%	6.16%	5.00%	5.07%	5.08%	5.11%	5.15%	5.17%	5.19%	5.21%	5.23%	5.24%	5.26%	5.28%	5.30%	5.32%	5.33%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.83%	1.58%	2.33%	3.02%	3.65%	4.25%	4.81%	5.33%	5.80%	6.24%	5.72%	5.77%	5.78%	5.80%	5.83%	5.85%	5.87%	5.88%	5.90%	5.92%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.27%	0.83%	1.39%	1.90%	2.39%	2.87%	3.31%	3.74%	4.14%	4.51%	4.87%	5.20%	5.52%	5.81%	6.08%	6.34%	6.58%	6.80%	7.00%	7.19%
Incremental Delivery Rate Impact Compared to Prior Year																				
Scenario 1: Expensing EEC Expenditures	15.91%	-11.62%	-0.09%	-0.04%	0.12%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.95%	1.15%	1.13%	1.02%	0.92%	-1.17%	0.07%	0.01%	0.03%	0.04%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.83%	0.76%	0.75%	0.68%	0.63%	0.60%	0.56%	0.52%	0.48%	0.44%	-0.52%	0.04%	0.01%	0.02%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.27%	0.56%	0.56%	0.52%	0.49%	0.47%	0.45%	0.42%	0.40%	0.38%	0.36%	0.33%	0.31%	0.29%	0.27%	0.26%	0.24%	0.22%	0.20%	0.19%

FEI EEC deferral impacts - Scenario 1: Expensing EEC Expenditures

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		3.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
4	STD %		3.03%	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
5	LTD Rate		6.87%	6.85%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	LTD %		56.97%	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
7	Return on Rate Base		7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
8	WACC		6.81%	6.82%	6.78%	6.77%	6.77%	6.77%	6.77%	6.77%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		576,730			588,265	600,030	612,030	624,271	636,757
12	EEC Expenditures excluding Switch & Shrink (2012-2013 Expenditures assumed to amortize all in 2014; 2014 onwards included in O&M forecast)		13,350	20,821	32,016	30,505 0	33,134 0	33,081 0	33,324 0	34,632
13	EEC Switch & Shrink Expenditures		630	653	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		24,444	16,528	22,698	29,458	-	-	-	-
19	Adjustments	Transfer from non-rate base				20,972				
20	Gross Additions		13,350	11,940	13,350	-	-	-	-	-
21	Tax		(3,338)	(3,674)	(3,438)	-	-	-	-	-
22	Net Additions	Sum of Lines 20 through 21	10,013	8,267	9,912	-	-	-	-	-
23	Amortization		(3,152)	(2,097)	(3,152)	(50,430)	-	-	-	-
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	31,305	22,698	29,458	-	-	-	-	-
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	27,874	19,613	26,078	25,215	-	-	-	-
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	6,660	20,972	-	-	-	-
30	Adjustments	Transfer to rate base				(20,972)				
31	Gross Additions		-	8,881	18,666	-	-	-	-	-
32	Tax		-	(2,220)	(4,806)	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	6,660	13,860	-	-	-	-	-
34	AFUDC		-	-	452	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	6,660	20,972	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	1,059	745	991	958	-	-	-	-
39	Add: Amortization	-Line 23	3,152	2,097	3,152	50,430	-	-	-	-
40	Taxable Income After Tax	Sum of Lines 38 through 39	4,211	2,842	4,143	51,388	-	-	-	-
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	5,615	3,790	5,580	69,443	-	-	-	-
45										
46	Tax Expense	Line 42 x Line 44	1,404	947	1,437	18,055	-	-	-	-
47										
48	**Revenue Requirement**									
49	O&M		630	653	-	30,505	33,134	33,081	33,324	34,632
50	Amortization	-Line 23	3,152	2,097	3,152	50,430	-	-	-	-
51	Tax Expense	Line 46	1,404	947	1,437	18,055	-	-	-	-
52	Earned Return	Line 26 x Line 7	2,180	1,535	2,039	1,972	-	-	-	-
53	Total Revenue Requirement	Sum of Lines 49 through 52	7,365	5,232	6,628	100,962	33,134	33,081	33,324	34,632
54	Cumulative Revenue Requirement Change vs. 2013 Approved					93,597	25,769	25,716	25,959	27,267
55	Forecast Delivery Margin	Line 11				588,265	600,030	612,030	624,271	636,757
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				15.91%	4.29%	4.20%	4.16%	4.28%
57	Incremental Delivery Rate Impact					15.91%	-11.62%	-0.09%	-0.04%	0.12%

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
#	26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
0	35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
27,959	28,666	29,386	30,121	30,871	31,636	32,416	33,211	34,023	34,851	35,695	36,556	37,435	38,331	39,245
649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
4.30%	4.33%	4.35%	4.37%	4.39%	4.41%	4.43%	4.45%	4.47%	4.49%	4.51%	4.53%	4.54%	4.56%	4.58%
0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%

FEI EEC deferral impacts - Scenario 2: Amortizing EEC Expenditures over 5 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		3.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
4	STD %		3.03%	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
5	LTD Rate		6.87%	6.85%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	LTD %		56.97%	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
7	Return on Rate Base		7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
8	WACC		6.81%	6.82%	6.78%	6.77%	6.77%	6.77%	6.77%	6.77%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		576,730			588,265	600,030	612,030	624,271	636,757
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 5 years beginning the following year)		13,350	20,821	32,016	30,505	33,134	33,081	33,324	34,632
13	EEC Switch & Shrink Expenditures (included in O&M)		630	653	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		24,444	16,528	22,698	29,458	62,918	72,836	77,811	78,071
19	Adjustments	Transfer from non-rate base				20,972				
20	Gross Additions		13,350	11,940	13,350	30,505	33,134	33,081	33,324	34,632
21	Tax		(3,338)	(3,674)	(3,438)	(7,931)	(8,615)	(8,601)	(8,664)	(9,004)
22	Net Additions	Sum of Lines 20 through 21	10,013	8,267	9,912	22,574	24,519	24,480	24,660	25,628
23	Amortization		(3,152)	(2,097)	(3,152)	(10,086)	(14,601)	(19,505)	(24,401)	(29,332)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	31,305	22,698	29,458	62,918	72,836	77,811	78,071	74,366
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	27,874	19,613	26,078	56,674	67,877	75,324	77,941	76,218
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	6,660	20,972	-	-	-	-
30	Adjustments	Transfer to rate base				(20,972)				
31	Gross Additions		-	8,881	18,666	-	-	-	-	-
32	Tax		-	(2,220)	(4,806)	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	6,660	13,860	-	-	-	-	-
34	AFUDC		-	-	452	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	6,660	20,972	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	1,059	745	991	2,154	2,579	2,862	2,962	2,896
39	Add: Amortization	-Line 23	3,152	2,097	3,152	10,086	14,601	19,505	24,401	29,332
40	Taxable Income After Tax	Sum of Lines 38 through 39	4,211	2,842	4,143	12,240	17,180	22,367	27,362	32,229
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	5,615	3,790	5,580	16,540	23,216	30,225	36,976	43,552
45										
46	Tax Expense	Line 42 x Line 44	1,404	947	1,437	4,300	6,036	7,859	9,614	11,324
47										
48	**Revenue Requirement**									
49	O&M		630	653	-	-	-	-	-	-
50	Amortization	-Line 23	3,152	2,097	3,152	10,086	14,601	19,505	24,401	29,332
51	Tax Expense	Line 46	1,404	947	1,437	4,300	6,036	7,859	9,614	11,324
52	Earned Return	Line 26 x Line 7	2,180	1,535	2,039	4,432	5,308	5,890	6,095	5,960
53	Total Revenue Requirement	Sum of Lines 49 through 52	7,365	5,232	6,628	18,818	25,945	33,253	40,109	46,616
54	Cumulative Revenue Requirement Change vs. 2013 Approved					11,453	18,579	25,888	32,744	39,251
55	Forecast Delivery Margin	Line 11				588,265	600,030	612,030	624,271	636,757
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				1.95%	3.10%	4.23%	5.25%	6.16%
57	Incremental Delivery Rate Impact					1.95%	1.15%	1.13%	1.02%	0.92%

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
#	26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
	35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
74,366	76,134	77,712	79,394	81,077	82,698	84,352	86,039	87,760	89,515	91,306	93,132	94,994	96,894	98,832
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
(9,184)	(9,368)	(9,555)	(9,747)	(9,941)	(10,140)	(10,343)	(10,550)	(10,761)	(10,976)	(11,196)	(11,420)	(11,648)	(11,881)	(12,119)
26,140	26,663	27,196	27,740	28,295	28,861	29,438	30,027	30,627	31,240	31,865	32,502	33,152	33,815	34,491
(24,372)	(25,085)	(25,514)	(26,057)	(26,673)	(27,207)	(27,751)	(28,306)	(28,872)	(29,450)	(30,039)	(30,639)	(31,252)	(31,877)	(32,515)
76,134	77,712	79,394	81,077	82,698	84,352	86,039	87,760	89,515	91,306	93,132	94,994	96,894	98,832	100,809
75,250	76,923	78,553	80,235	81,887	83,525	85,196	86,900	88,638	90,410	92,219	94,063	95,944	97,863	99,820
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,859	2,923	2,985	3,049	3,112	3,174	3,237	3,302	3,368	3,436	3,504	3,574	3,646	3,719	3,793
24,372	25,085	25,514	26,057	26,673	27,207	27,751	28,306	28,872	29,450	30,039	30,639	31,252	31,877	32,515
27,232	28,008	28,499	29,106	29,785	30,381	30,989	31,608	32,240	32,885	33,543	34,214	34,898	35,596	36,308
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
36,799	37,849	38,512	39,333	40,250	41,055	41,876	42,714	43,568	44,440	45,328	46,235	47,160	48,103	49,065
9,568	9,841	10,013	10,227	10,465	10,674	10,888	11,106	11,328	11,554	11,785	12,021	12,262	12,507	12,757
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24,372	25,085	25,514	26,057	26,673	27,207	27,751	28,306	28,872	29,450	30,039	30,639	31,252	31,877	32,515
9,568	9,841	10,013	10,227	10,465	10,674	10,888	11,106	11,328	11,554	11,785	12,021	12,262	12,507	12,757
5,884	6,015	6,143	6,274	6,404	6,532	6,662	6,795	6,931	7,070	7,211	7,356	7,503	7,653	7,806
39,824	40,941	41,670	42,558	43,542	44,413	45,301	46,207	47,131	48,074	49,035	50,016	51,016	52,037	53,078
32,459	33,576	34,305	35,193	36,177	37,047	37,936	38,842	39,766	40,709	41,670	42,651	43,651	44,671	45,712
649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
5.00%	5.07%	5.08%	5.11%	5.15%	5.17%	5.19%	5.21%	5.23%	5.24%	5.26%	5.28%	5.30%	5.32%	5.33%
-1.17%	0.07%	0.01%	0.03%	0.04%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%

FEI EEC deferral impacts - Scenario 3: Amortizing EEC Expenditures over 10 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		3.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
4	STD %		3.03%	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
5	LTD Rate		6.87%	6.85%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	LTD %		56.97%	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
7	Return on Rate Base		7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
8	WACC		6.81%	6.82%	6.78%	6.77%	6.77%	6.77%	6.77%	6.77%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		576,730			588,265	600,030	612,030	624,271	636,757
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 10 years beginning the following year)		13,350	20,821	32,016	30,505	33,134	33,081	33,324	34,632
13	EEC Switch & Shrink Expenditures (included in O&M)		630	653	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		24,444	16,528	22,698	29,458	67,961	85,179	99,907	112,367
19	Adjustments	Transfer from non-rate base				20,972				
20	Gross Additions		13,350	11,940	13,350	30,505	33,134	33,081	33,324	34,632
21	Tax		(3,338)	(3,674)	(3,438)	(7,931)	(8,615)	(8,601)	(8,664)	(9,004)
22	Net Additions	Sum of Lines 20 through 21	10,013	8,267	9,912	22,574	24,519	24,480	24,660	25,628
23	Amortization		(3,152)	(2,097)	(3,152)	(5,043)	(7,300)	(9,752)	(12,200)	(14,666)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	31,305	22,698	29,458	67,961	85,179	99,907	112,367	123,328
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	27,874	19,613	26,078	59,195	76,570	92,543	106,137	117,847
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	6,660	20,972	-	-	-	-
30	Adjustments	Transfer to rate base				(20,972)				
31	Gross Additions		-	8,881	18,666	-	-	-	-	-
32	Tax		-	(2,220)	(4,806)	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	6,660	13,860	-	-	-	-	-
34	AFUDC		-	-	452	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	6,660	20,972	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	1,059	745	991	2,249	2,910	3,517	4,033	4,478
39	Add: Amortization	-Line 23	3,152	2,097	3,152	5,043	7,300	9,752	12,200	14,666
40	Taxable Income After Tax	Sum of Lines 38 through 39	4,211	2,842	4,143	7,292	10,210	13,269	16,233	19,144
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	5,615	3,790	5,580	9,855	13,797	17,931	21,937	25,871
45										
46	Tax Expense	Line 42 x Line 44	1,404	947	1,437	2,562	3,587	4,662	5,704	6,726
47										
48	**Revenue Requirement**									
49	O&M		630	653	-	-	-	-	-	-
50	Amortization	-Line 23	3,152	2,097	3,152	5,043	7,300	9,752	12,200	14,666
51	Tax Expense	Line 46	1,404	947	1,437	2,562	3,587	4,662	5,704	6,726
52	Earned Return	Line 26 x Line 7	2,180	1,535	2,039	4,629	5,988	7,237	8,300	9,216
53	Total Revenue Requirement	Sum of Lines 49 through 52	7,365	5,232	6,628	12,234	16,875	21,651	26,204	30,608
54	Cumulative Revenue Requirement Change vs. 2013 Approved					4,869	9,510	14,286	18,838	23,243
55	Forecast Delivery Margin	Line 11				588,265	600,030	612,030	624,271	636,757
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				0.83%	1.58%	2.33%	3.02%	3.65%
57	Incremental Delivery Rate Impact					0.83%	0.76%	0.75%	0.68%	0.63%

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
# 26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
123,328	132,239	139,059	143,746	146,257	146,549	149,621	152,641	155,758	158,920	162,099	165,341	168,647	172,020	175,461
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
(9,184)	(9,368)	(9,555)	(9,747)	(9,941)	(10,140)	(10,343)	(10,550)	(10,761)	(10,976)	(11,196)	(11,420)	(11,648)	(11,881)	(12,119)
26,140	26,663	27,196	27,740	28,295	28,861	29,438	30,027	30,627	31,240	31,865	32,502	33,152	33,815	34,491
(17,229)	(19,843)	(22,509)	(25,229)	(28,003)	(25,790)	(26,418)	(26,910)	(27,465)	(28,062)	(28,623)	(29,195)	(29,779)	(30,375)	(30,982)
132,239	139,059	143,746	146,257	146,549	149,621	152,641	155,758	158,920	162,099	165,341	168,647	172,020	175,461	178,970
127,784	135,649	141,403	145,002	146,403	148,085	151,131	154,199	157,339	160,509	163,720	166,994	170,334	173,741	177,215
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4,856	5,155	5,373	5,510	5,563	5,627	5,743	5,860	5,979	6,099	6,221	6,346	6,473	6,602	6,734
17,229	19,843	22,509	25,229	28,003	25,790	26,418	26,910	27,465	28,062	28,623	29,195	29,779	30,375	30,982
22,085	24,998	27,883	30,739	33,566	31,417	32,161	32,770	33,444	34,161	34,844	35,541	36,252	36,977	37,716
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
29,844	33,781	37,679	41,539	45,360	42,455	43,461	44,283	45,194	46,163	47,087	48,028	48,989	49,969	50,968
7,760	8,783	9,797	10,800	11,794	11,038	11,300	11,514	11,750	12,002	12,243	12,487	12,737	12,992	13,252
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17,229	19,843	22,509	25,229	28,003	25,790	26,418	26,910	27,465	28,062	28,623	29,195	29,779	30,375	30,982
7,760	8,783	9,797	10,800	11,794	11,038	11,300	11,514	11,750	12,002	12,243	12,487	12,737	12,992	13,252
9,993	10,608	11,058	11,339	11,449	11,580	11,818	12,058	12,304	12,552	12,803	13,059	13,320	13,586	13,858
34,981	39,234	43,363	47,368	51,245	48,408	49,536	50,482	51,519	52,616	53,668	54,741	55,836	56,953	58,092
27,616	31,868	35,998	40,003	43,880	41,042	42,171	43,117	44,154	45,250	46,303	47,376	48,471	49,588	50,727
649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
4.25%	4.81%	5.33%	5.80%	6.24%	5.72%	5.77%	5.78%	5.80%	5.83%	5.85%	5.87%	5.88%	5.90%	5.92%
0.60%	0.56%	0.52%	0.48%	0.44%	-0.52%	0.04%	0.01%	0.02%	0.03%	0.02%	0.02%	0.02%	0.02%	0.02%

FEI EEC deferral impacts - Scenario 4: Amortizing EEC Expenditures over 20 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		3.50%	2.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
4	STD %		3.03%	1.93%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
5	LTD Rate		6.87%	6.85%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
6	LTD %		56.97%	58.07%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
7	Return on Rate Base		7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
8	WACC		6.81%	6.82%	6.78%	6.77%	6.77%	6.77%	6.77%	6.77%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		576,730			588,265	600,030	612,030	624,271	636,757
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 20 years beginning the following year)		13,350	20,821	32,016	30,505	33,134	33,081	33,324	34,632
13	EEC Switch & Shrink Expenditures (included in O&M)		630	653	-	-	-	-	-	-
14										
15										
16			2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
17	**Rate Base EEC Deferral**									
18	Opening Deferral		24,444	16,528	22,698	29,458	70,482	91,351	110,955	129,515
19	Adjustments	Transfer from non-rate base				20,972				
20	Gross Additions		13,350	11,940	13,350	30,505	33,134	33,081	33,324	34,632
21	Tax		(3,338)	(3,674)	(3,438)	(7,931)	(8,615)	(8,601)	(8,664)	(9,004)
22	Net Additions	Sum of Lines 20 through 21	10,013	8,267	9,912	22,574	24,519	24,480	24,660	25,628
23	Amortization		(3,152)	(2,097)	(3,152)	(2,521)	(3,650)	(4,876)	(6,100)	(7,333)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	31,305	22,698	29,458	70,482	91,351	110,955	129,515	147,809
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	27,874	19,613	26,078	60,456	80,917	101,153	120,235	138,662
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	6,660	20,972	-	-	-	-
30	Adjustments	Transfer to rate base				(20,972)				
31	Gross Additions		-	8,881	18,666	-	-	-	-	-
32	Tax		-	(2,220)	(4,806)	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	6,660	13,860	-	-	-	-	-
34	AFUDC		-	-	452	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	6,660	20,972	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	1,059	745	991	2,297	3,075	3,844	4,569	5,269
39	Add: Amortization	-Line 23	3,152	2,097	3,152	2,521	3,650	4,876	6,100	7,333
40	Taxable Income After Tax	Sum of Lines 38 through 39	4,211	2,842	4,143	4,819	6,725	8,720	10,669	12,602
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	5,615	3,790	5,580	6,512	9,088	11,784	14,418	17,030
45										
46	Tax Expense	Line 42 x Line 44	1,404	947	1,437	1,693	2,363	3,064	3,749	4,428
47										
48	**Revenue Requirement**									
49	O&M		630	653	-	-	-	-	-	-
50	Amortization	-Line 23	3,152	2,097	3,152	2,521	3,650	4,876	6,100	7,333
51	Tax Expense	Line 46	1,404	947	1,437	1,693	2,363	3,064	3,749	4,428
52	Earned Return	Line 26 x Line 7	2,180	1,535	2,039	4,728	6,328	7,910	9,402	10,843
53	Total Revenue Requirement	Sum of Lines 49 through 52	7,365	5,232	6,628	8,942	12,341	15,850	19,251	22,604
54	Cumulative Revenue Requirement Change vs. 2013 Approved					1,577	4,975	8,484	11,885	15,239
55	Forecast Delivery Margin	Line 11				588,265	600,030	612,030	624,271	636,757
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				0.27%	0.83%	1.39%	1.90%	2.39%
57	Incremental Delivery Rate Impact					0.27%	0.56%	0.56%	0.52%	0.49%

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%	3.03%
6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%	6.87%
56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%	56.97%
7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%	7.82%
6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
# 26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	**2020 Forecast**	**2021 Forecast**	**2022 Forecast**	**2023 Forecast**	**2024 Forecast**	**2025 Forecast**	**2026 Forecast**	**2027 Forecast**	**2028 Forecast**	**2029 Forecast**	**2030 Forecast**	**2031 Forecast**	**2032 Forecast**	**2033 Forecast**
147,809	165,335	182,076	198,018	213,144	227,437	240,882	253,461	265,156	275,951	285,827	294,766	302,749	309,757	315,770
35,325	36,031	36,752	37,487	38,237	39,001	39,781	40,577	41,388	42,216	43,061	43,922	44,800	45,696	46,610
(9,184)	(9,368)	(9,555)	(9,747)	(9,941)	(10,140)	(10,343)	(10,550)	(10,761)	(10,976)	(11,196)	(11,420)	(11,648)	(11,881)	(12,119)
26,140	26,663	27,196	27,740	28,295	28,861	29,438	30,027	30,627	31,240	31,865	32,502	33,152	33,815	34,491
(8,615)	(9,922)	(11,255)	(12,614)	(14,001)	(15,416)	(16,859)	(18,331)	(19,833)	(21,364)	(22,926)	(24,519)	(26,144)	(27,802)	(29,493)
165,335	182,076	198,018	213,144	227,437	240,882	253,461	265,156	275,951	285,827	294,766	302,749	309,757	315,770	320,769
156,572	173,706	190,047	205,581	220,290	234,160	247,171	259,309	270,554	280,889	290,297	298,758	306,253	312,764	318,270
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5,950	6,601	7,222	7,812	8,371	8,898	9,393	9,854	10,281	10,674	11,031	11,353	11,638	11,885	12,094
8,615	9,922	11,255	12,614	14,001	15,416	16,859	18,331	19,833	21,364	22,926	24,519	26,144	27,802	29,493
14,564	16,522	18,476	20,427	22,373	24,314	26,252	28,185	30,114	32,038	33,957	35,872	37,782	39,687	41,587
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
19,681	22,327	24,968	27,603	30,233	32,857	35,475	38,088	40,694	43,294	45,888	48,476	51,057	53,631	56,198
5,117	5,805	6,492	7,177	7,861	8,543	9,224	9,903	10,580	11,256	11,931	12,604	13,275	13,944	14,612
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8,615	9,922	11,255	12,614	14,001	15,416	16,859	18,331	19,833	21,364	22,926	24,519	26,144	27,802	29,493
5,117	5,805	6,492	7,177	7,861	8,543	9,224	9,903	10,580	11,256	11,931	12,604	13,275	13,944	14,612
12,244	13,584	14,861	16,076	17,226	18,311	19,329	20,278	21,157	21,965	22,701	23,363	23,949	24,458	24,888
25,975	29,310	32,608	35,868	39,089	42,270	45,411	48,512	51,570	54,586	57,558	60,485	63,368	66,204	68,993
18,610	21,945	25,242	28,502	31,723	34,905	38,046	41,146	44,205	47,220	50,192	53,120	56,002	58,838	61,627
649,492	662,481	675,731	689,246	703,031	717,091	731,433	746,062	760,983	776,203	791,727	807,561	823,712	840,187	856,990
2.87%	3.31%	3.74%	4.14%	4.51%	4.87%	5.20%	5.52%	5.81%	6.08%	6.34%	6.58%	6.80%	7.00%	7.19%
0.47%	0.45%	0.42%	0.40%	0.38%	0.36%	0.33%	0.31%	0.29%	0.27%	0.26%	0.24%	0.22%	0.20%	0.19%

FEVI Summary of Notional Rate Impacts

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative Notional Delivery Rate Impact Compared to 2013 Approved																				
Scenario 1: Expensing EEC Expenditures	6.20%	1.60%	1.62%	1.62%	1.59%	1.60%	1.61%	1.61%	1.62%	1.63%	1.63%	1.64%	1.65%	1.65%	1.66%	1.67%	1.67%	1.68%	1.68%	1.69%
Scenario 2: Amortizing EEC Expenditures over 5 years	0.83%	1.24%	1.65%	2.02%	2.36%	1.87%	1.89%	1.89%	1.88%	1.88%	1.89%	1.90%	1.90%	1.91%	1.92%	1.92%	1.93%	1.94%	1.94%	1.95%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.39%	0.66%	0.93%	1.18%	1.41%	1.62%	1.81%	2.00%	2.16%	2.32%	2.10%	2.11%	2.11%	2.11%	2.12%	2.12%	2.13%	2.13%	2.14%	2.15%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.17%	0.37%	0.56%	0.75%	0.93%	1.09%	1.25%	1.40%	1.54%	1.67%	1.79%	1.91%	2.02%	2.12%	2.22%	2.31%	2.39%	2.47%	2.54%	2.60%
Incremental Notional Delivery Rate Impact Compared to Prior Year																				
Scenario 1: Expensing EEC Expenditures	6.20%	-4.60%	0.02%	0.00%	-0.03%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Scenario 2: Amortizing EEC Expenditures over 5 years	0.83%	0.41%	0.40%	0.38%	0.34%	-0.50%	0.02%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.39%	0.27%	0.27%	0.25%	0.23%	0.21%	0.20%	0.18%	0.17%	0.15%	-0.22%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.17%	0.20%	0.20%	0.19%	0.18%	0.16%	0.16%	0.15%	0.14%	0.13%	0.12%	0.12%	0.11%	0.10%	0.10%	0.09%	0.08%	0.08%	0.07%	0.07%

FEVI EEC deferral impacts - Scenario 1: Expensing EEC Expenditures

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		5.00%	4.00%	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00%
4	STD %		16.69%	13.13%	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69%
5	LTD Rate		5.85%	5.73%	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85%
6	LTD %		43.31%	46.87%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
7	Return on Rate Base		7.37%	7.21%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
8	WACC		6.53%	6.41%	6.50%	6.49%	6.49%	6.49%	6.49%	6.49%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Revenue (inflated beginning 2014)		199,982			203,982	208,061	212,222	216,467	220,796
12	EEC Expenditures excluding Switch & Shrink (2012-2013 Expenditures assumed to amortize all in 2014; 2014 onwards included in O&M forecast)		1,500	2,939	3,557	3,848 0	4,169 #	4,278 0	4,340 0	4,350
13	EEC Switch & Shrink Expenditures		-	-	-	-	-	-	-	-
14										
15										
16			2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
17	**Rate Base EEC Deferral**									
18	Opening Deferral		3,713	2,834	4,742	6,909	-	-	-	-
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		1,500	2,939	3,557	-	-	-	-	-
21	Tax		(375)	(735)	(916)	-	-	-	-	-
22	Net Additions	Sum of Lines 20 through 21	1,125	2,204	2,641	-	-	-	-	-
23	Amortization		(359)	(296)	(474)	(6,909)	-	-	-	-
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	4,479	4,742	6,909	-	-	-	-	-
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	4,096	3,788	5,826	3,455	-	-	-	-
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	164	152	233	138	-	-	-	-
39	Add: Amortization	-Line 23	359	296	474	6,909	-	-	-	-
40	Taxable Income After Tax	Sum of Lines 38 through 39	523	448	707	7,047	-	-	-	-
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	697	597	953	9,523	-	-	-	-
45										
46	Tax Expense	Line 42 x Line 44	174	149	245	2,476	-	-	-	-
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	3,848	4,169	4,278	4,340	4,350
50	Amortization	-Line 23	359	296	474	6,909	-	-	-	-
51	Tax Expense	Line 46	174	149	245	2,476	-	-	-	-
52	Earned Return	Line 26 x Line 7	302	273	429	255	-	-	-	-
53	Total Revenue Requirement	Sum of Lines 49 through 52	835	719	1,149	13,488	4,169	4,278	4,340	4,350
54	Cumulative Revenue Requirement Change vs. 2013 Approved					12,653	3,334	3,443	3,505	3,515
55	Forecast Delivery Margin	Line 11				203,982	208,061	212,222	216,467	220,796
56	Cumulative Notional Delivery Rate Impact	Line 54 / Line 55				6.20%	1.60%	1.62%	1.62%	1.59%
57	Incremental Notional Delivery Rate Impact					6.20%	-4.60%	0.02%	0.00%	-0.03%

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
#	10.00%	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00%
	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
#	5.00%	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00% #	5.00%
#	16.69%	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69% #	16.69%
#	5.85%	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85% #	5.85%
	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%
#	26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
0	4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
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-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
3,602	3,691	3,781	3,874	3,968	4,064	4,162	4,262	4,364	4,468	4,574	4,682	4,792	4,905	5,019
225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
1.60%	1.61%	1.61%	1.62%	1.63%	1.63%	1.64%	1.65%	1.65%	1.66%	1.67%	1.67%	1.68%	1.68%	1.69%
0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%

FEVI EEC deferral impacts - Scenario 2: Amortizing EEC Expenditures over 5 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		5.00%	4.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
4	STD %		16.69%	13.13%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%
5	LTD Rate		5.85%	5.73%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
6	LTD %		43.31%	46.87%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
7	Return on Rate Base		7.37%	7.21%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
8	WACC		6.53%	6.41%	6.50%	6.49%	6.49%	6.49%	6.49%	6.49%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Revenue (inflated beginning 2014)		199,982			203,982	208,061	212,222	216,467	220,796
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 5 years beginning the following year)		1,500	2,939	3,557	3,848	4,169	4,278	4,340	4,350
13	EEC Switch & Shrink Expenditures (included in O&M)		-	-	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		3,713	2,834	4,742	6,909	8,375	9,509	10,106	10,116
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		1,500	2,939	3,557	3,848	4,169	4,278	4,340	4,350
21	Tax		(375)	(735)	(916)	(1,000)	(1,084)	(1,112)	(1,128)	(1,131)
22	Net Additions	Sum of Lines 20 through 21	1,125	2,204	2,641	2,848	3,085	3,166	3,212	3,219
23	Amortization		(359)	(296)	(474)	(1,382)	(1,951)	(2,568)	(3,201)	(3,844)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	4,479	4,742	6,909	8,375	9,509	10,106	10,116	9,491
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	4,096	3,788	5,826	7,642	8,942	9,807	10,111	9,804
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	164	152	233	306	358	392	404	392
39	Add: Amortization	-Line 23	359	296	474	1,382	1,951	2,568	3,201	3,844
40	Taxable Income After Tax	Sum of Lines 38 through 39	523	448	707	1,688	2,309	2,961	3,606	4,236
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	697	597	953	2,280	3,120	4,001	4,873	5,724
45										
46	Tax Expense	Line 42 x Line 44	174	149	245	593	811	1,040	1,267	1,488
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	-	-	-	-	-
50	Amortization	-Line 23	359	296	474	1,382	1,951	2,568	3,201	3,844
51	Tax Expense	Line 46	174	149	245	593	811	1,040	1,267	1,488
52	Earned Return	Line 26 x Line 7	302	273	429	563	659	723	745	722
53	Total Revenue Requirement	Sum of Lines 49 through 52	835	719	1,149	2,538	3,421	4,331	5,213	6,054
54	Cumulative Revenue Requirement Change vs. 2013 Approved					1,703	2,586	3,496	4,378	5,219
55	Forecast Delivery Margin	Line 11				203,982	208,061	212,222	216,467	220,796
56	Cumulative Notional Delivery Rate Impact	Line 54 / Line 55				0.83%	1.24%	1.65%	2.02%	2.36%
57	Incremental Notional Delivery Rate Impact					0.83%	0.41%	0.40%	0.38%	0.34%

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%
5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%
26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
9,491	9,669	9,825	9,995	10,184	10,387	10,595	10,807	11,023	11,244	11,469	11,698	11,932	12,171	12,414
4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
(1,154)	(1,177)	(1,200)	(1,224)	(1,249)	(1,274)	(1,299)	(1,325)	(1,352)	(1,379)	(1,406)	(1,434)	(1,463)	(1,492)	(1,522)
3,283	3,349	3,416	3,484	3,554	3,625	3,698	3,772	3,847	3,924	4,002	4,082	4,164	4,247	4,332
(3,106)	(3,193)	(3,246)	(3,296)	(3,350)	(3,417)	(3,486)	(3,555)	(3,627)	(3,699)	(3,773)	(3,849)	(3,925)	(4,004)	(4,084)
9,669	9,825	9,995	10,184	10,387	10,595	10,807	11,023	11,244	11,469	11,698	11,932	12,171	12,414	12,662
9,580	9,747	9,910	10,089	10,286	10,491	10,701	10,915	11,133	11,356	11,583	11,815	12,051	12,292	12,538
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	390	396	404	411	420	428	437	445	454	463	473	482	492	502
3,106	3,193	3,246	3,296	3,350	3,417	3,486	3,555	3,627	3,699	3,773	3,849	3,925	4,004	4,084
3,489	3,583	3,642	3,699	3,762	3,837	3,914	3,992	4,072	4,153	4,236	4,321	4,408	4,496	4,586
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
4,715	4,842	4,922	4,999	5,083	5,185	5,289	5,395	5,503	5,613	5,725	5,839	5,956	6,075	6,197
1,226	1,259	1,280	1,300	1,322	1,348	1,375	1,403	1,431	1,459	1,488	1,518	1,549	1,580	1,611
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3,106	3,193	3,246	3,296	3,350	3,417	3,486	3,555	3,627	3,699	3,773	3,849	3,925	4,004	4,084
1,226	1,259	1,280	1,300	1,322	1,348	1,375	1,403	1,431	1,459	1,488	1,518	1,549	1,580	1,611
706	718	730	743	758	773	788	804	820	837	853	871	888	906	924
5,038	5,170	5,256	5,339	5,430	5,539	5,649	5,762	5,878	5,995	6,115	6,237	6,362	6,489	6,619
4,202	4,335	4,421	4,504	4,595	4,703	4,814	4,927	5,042	5,160	5,280	5,402	5,527	5,654	5,784
225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
1.87%	1.89%	1.89%	1.88%	1.88%	1.89%	1.90%	1.90%	1.91%	1.92%	1.92%	1.93%	1.94%	1.94%	1.95%
-0.50%	0.02%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%

FEVI EEC deferral impacts - Scenario 3: Amortizing EEC Expenditures over 10 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		5.00%	4.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
4	STD %		16.69%	13.13%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%
5	LTD Rate		5.85%	5.73%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
6	LTD %		43.31%	46.87%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
7	Return on Rate Base		7.37%	7.21%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
8	WACC		6.53%	6.41%	6.50%	6.49%	6.49%	6.49%	6.49%	6.49%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Revenue (inflated beginning 2014)		199,982			203,982	208,061	212,222	216,467	220,796
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 10 years beginning the following year)		1,500	2,939	3,557	3,848	4,169	4,278	4,340	4,350
13	EEC Switch & Shrink Expenditures (included in O&M)		-	-	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		3,713	2,834	4,742	6,909	9,066	11,175	13,057	14,668
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		1,500	2,939	3,557	3,848	4,169	4,278	4,340	4,350
21	Tax		(375)	(735)	(916)	(1,000)	(1,084)	(1,112)	(1,128)	(1,131)
22	Net Additions	Sum of Lines 20 through 21	1,125	2,204	2,641	2,848	3,085	3,166	3,212	3,219
23	Amortization		(359)	(296)	(474)	(691)	(976)	(1,284)	(1,601)	(1,922)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	4,479	4,742	6,909	9,066	11,175	13,057	14,668	15,965
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	4,096	3,788	5,826	7,987	10,120	12,116	13,862	15,316
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	164	152	233	319	405	485	554	613
39	Add: Amortization	-Line 23	359	296	474	691	976	1,284	1,601	1,922
40	Taxable Income After Tax	Sum of Lines 38 through 39	523	448	707	1,010	1,380	1,769	2,155	2,535
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	697	597	953	1,365	1,866	2,390	2,912	3,425
45										
46	Tax Expense	Line 42 x Line 44	174	149	245	355	485	621	757	891
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	-	-	-	-	-
50	Amortization	-Line 23	359	296	474	691	976	1,284	1,601	1,922
51	Tax Expense	Line 46	174	149	245	355	485	621	757	891
52	Earned Return	Line 26 x Line 7	302	273	429	589	746	893	1,021	1,129
53	Total Revenue Requirement	Sum of Lines 49 through 52	835	719	1,149	1,634	2,206	2,798	3,379	3,941
54	Cumulative Revenue Requirement Change vs. 2013 Approved					799	1,371	1,963	2,544	3,106
55	Forecast Delivery Margin	Line 11				203,982	208,061	212,222	216,467	220,796
56	Cumulative Notional Delivery Rate Impact	Line 54 / Line 55				0.39%	0.66%	0.93%	1.18%	1.41%
57	Incremental Notional Delivery Rate Impact					0.39%	0.27%	0.27%	0.25%	0.23%

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%
	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%
#	26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
	4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
15,965	17,004	17,781	18,290	18,526	18,483	18,846	19,205	19,576	19,961	20,361	20,768	21,183	21,607	22,039
4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
(1,154)	(1,177)	(1,200)	(1,224)	(1,249)	(1,274)	(1,299)	(1,325)	(1,352)	(1,379)	(1,406)	(1,434)	(1,463)	(1,492)	(1,522)
3,283	3,349	3,416	3,484	3,554	3,625	3,698	3,772	3,847	3,924	4,002	4,082	4,164	4,247	4,332
(2,244)	(2,572)	(2,907)	(3,249)	(3,597)	(3,262)	(3,339)	(3,401)	(3,461)	(3,525)	(3,595)	(3,667)	(3,740)	(3,815)	(3,892)
17,004	17,781	18,290	18,526	18,483	18,846	19,205	19,576	19,961	20,361	20,768	21,183	21,607	22,039	22,480
16,484	17,393	18,036	18,408	18,504	18,665	19,025	19,390	19,768	20,161	20,564	20,976	21,395	21,823	22,259
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
659	696	721	736	740	747	761	776	791	806	823	839	856	873	890
2,244	2,572	2,907	3,249	3,597	3,262	3,339	3,401	3,461	3,525	3,595	3,667	3,740	3,815	3,892
2,903	3,268	3,628	3,985	4,337	4,008	4,100	4,176	4,252	4,331	4,418	4,506	4,596	4,688	4,782
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
3,923	4,416	4,903	5,385	5,861	5,416	5,541	5,644	5,746	5,853	5,970	6,089	6,211	6,335	6,462
1,020	1,148	1,275	1,400	1,524	1,408	1,441	1,467	1,494	1,522	1,552	1,583	1,615	1,647	1,680
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2,244	2,572	2,907	3,249	3,597	3,262	3,339	3,401	3,461	3,525	3,595	3,667	3,740	3,815	3,892
1,020	1,148	1,275	1,400	1,524	1,408	1,441	1,467	1,494	1,522	1,552	1,583	1,615	1,647	1,680
1,215	1,282	1,329	1,356	1,363	1,375	1,402	1,429	1,457	1,485	1,515	1,546	1,576	1,608	1,640
4,478	5,002	5,511	6,005	6,484	6,045	6,182	6,297	6,412	6,532	6,663	6,796	6,932	7,070	7,212
3,643	4,167	4,676	5,170	5,649	5,210	5,347	5,462	5,577	5,697	5,828	5,961	6,097	6,235	6,377
225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
1.62%	1.81%	2.00%	2.16%	2.32%	2.10%	2.11%	2.11%	2.11%	2.12%	2.12%	2.13%	2.13%	2.14%	2.15%
0.21%	0.20%	0.18%	0.17%	0.15%	-0.22%	0.01%	0.00%	0.00%	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%

FEVI EEC deferral impacts - Scenario 4: Amortizing EEC Expenditures over 20 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		5.00%	4.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
4	STD %		16.69%	13.13%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%
5	LTD Rate		5.85%	5.73%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
6	LTD %		43.31%	46.87%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
7	Return on Rate Base		7.37%	7.21%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
8	WACC		6.53%	6.41%	6.50%	6.49%	6.49%	6.49%	6.49%	6.49%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Revenue (inflated beginning 2014)		199,982			203,982	208,061	212,222	216,467	220,796
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 20 years beginning the following year)		1,500	2,939	3,557	3,848	4,169	4,278	4,340	4,350
13	EEC Switch & Shrink Expenditures (included in O&M)		-	-	-	-	-	-	-	-
14										
15										
16			2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
17	**Rate Base EEC Deferral**									
18	Opening Deferral		3,713	2,834	4,742	6,909	9,411	12,008	14,532	16,943
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		1,500	2,939	3,557	3,848	4,169	4,278	4,340	4,350
21	Tax		(375)	(735)	(916)	(1,000)	(1,084)	(1,112)	(1,128)	(1,131)
22	Net Additions	Sum of Lines 20 through 21	1,125	2,204	2,641	2,848	3,085	3,166	3,212	3,219
23	Amortization		(359)	(296)	(474)	(345)	(488)	(642)	(800)	(961)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	4,479	4,742	6,909	9,411	12,008	14,532	16,943	19,201
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	4,096	3,788	5,826	8,160	10,710	13,270	15,738	18,072
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	164	152	233	326	428	531	630	723
39	Add: Amortization	-Line 23	359	296	474	345	488	642	800	961
40	Taxable Income After Tax	Sum of Lines 38 through 39	523	448	707	672	916	1,173	1,430	1,684
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	697	597	953	908	1,238	1,585	1,932	2,275
45										
46	Tax Expense	Line 42 x Line 44	174	149	245	236	322	412	502	592
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	-	-	-	-	-
50	Amortization	-Line 23	359	296	474	345	488	642	800	961
51	Tax Expense	Line 46	174	149	245	236	322	412	502	592
52	Earned Return	Line 26 x Line 7	302	273	429	601	789	978	1,160	1,332
53	Total Revenue Requirement	Sum of Lines 49 through 52	835	719	1,149	1,183	1,599	2,032	2,462	2,884
54	Cumulative Revenue Requirement Change vs. 2013 Approved					348	764	1,197	1,627	2,049
55	Forecast Delivery Margin	Line 11				203,982	208,061	212,222	216,467	220,796
56	Cumulative Notional Delivery Rate Impact	Line 54 / Line 55				0.17%	0.37%	0.56%	0.75%	0.93%
57	Incremental Notional Delivery Rate Impact					0.17%	0.20%	0.20%	0.19%	0.18%

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%	16.69%
	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%	5.85%
	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%	43.31%
	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%	7.37%
	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%	6.49%
#	26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
	4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
19,201	21,363	23,426	25,388	27,248	29,004	30,653	32,193	33,622	34,938	36,139	37,222	38,184	39,025	39,740
4,437	4,526	4,616	4,709	4,803	4,899	4,997	5,097	5,199	5,303	5,409	5,517	5,627	5,740	5,855
(1,154)	(1,177)	(1,200)	(1,224)	(1,249)	(1,274)	(1,299)	(1,325)	(1,352)	(1,379)	(1,406)	(1,434)	(1,463)	(1,492)	(1,522)
3,283	3,349	3,416	3,484	3,554	3,625	3,698	3,772	3,847	3,924	4,002	4,082	4,164	4,247	4,332
(1,122)	(1,286)	(1,454)	(1,624)	(1,799)	(1,976)	(2,158)	(2,342)	(2,531)	(2,723)	(2,920)	(3,120)	(3,324)	(3,532)	(3,744)
21,363	23,426	25,388	27,248	29,004	30,653	32,193	33,622	34,938	36,139	37,222	38,184	39,025	39,740	40,328
20,282	22,394	24,407	26,318	28,126	29,828	31,423	32,907	34,280	35,538	36,680	37,703	38,605	39,383	40,034
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
811	896	976	1,053	1,125	1,193	1,257	1,316	1,371	1,422	1,467	1,508	1,544	1,575	1,601
1,122	1,286	1,454	1,624	1,799	1,976	2,158	2,342	2,531	2,723	2,920	3,120	3,324	3,532	3,744
1,933	2,182	2,430	2,677	2,924	3,169	3,414	3,659	3,902	4,145	4,387	4,628	4,868	5,107	5,346
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
2,612	2,948	3,284	3,618	3,951	4,283	4,614	4,944	5,273	5,601	5,928	6,254	6,578	6,902	7,224
679	767	854	941	1,027	1,114	1,200	1,285	1,371	1,456	1,541	1,626	1,710	1,794	1,878
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1,122	1,286	1,454	1,624	1,799	1,976	2,158	2,342	2,531	2,723	2,920	3,120	3,324	3,532	3,744
679	767	854	941	1,027	1,114	1,200	1,285	1,371	1,456	1,541	1,626	1,710	1,794	1,878
1,494	1,650	1,798	1,939	2,072	2,198	2,315	2,425	2,526	2,619	2,703	2,778	2,844	2,902	2,950
3,296	3,703	4,106	4,504	4,898	5,288	5,672	6,053	6,428	6,798	7,163	7,524	7,879	8,228	8,572
2,460	2,868	3,271	3,669	4,063	4,453	4,837	5,217	5,593	5,963	6,328	6,689	7,043	7,393	7,737
225,212	229,716	234,311	238,997	243,777	248,652	253,626	258,698	263,872	269,149	274,532	280,023	285,624	291,336	297,163
1.09%	1.25%	1.40%	1.54%	1.67%	1.79%	1.91%	2.02%	2.12%	2.22%	2.31%	2.39%	2.47%	2.54%	2.60%
0.16%	0.16%	0.15%	0.14%	0.13%	0.12%	0.12%	0.11%	0.10%	0.10%	0.09%	0.08%	0.08%	0.07%	0.07%

FEW Summary of Rate Impacts

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cumulative Delivery Rate Impact Compared to 2013 Approved																				
Scenario 1: Expensing EEC Expenditures	9.75%	4.15%	4.08%	4.03%	4.10%	4.11%	4.11%	4.12%	4.12%	4.13%	4.14%	4.14%	4.15%	4.15%	4.16%	4.16%	4.17%	4.17%	4.18%	4.18%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.24%	2.22%	3.18%	4.06%	4.86%	4.61%	4.65%	4.65%	4.65%	4.67%	4.68%	4.68%	4.69%	4.69%	4.70%	4.70%	4.71%	4.71%	4.72%	4.72%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.69%	1.31%	1.93%	2.49%	3.02%	3.52%	3.98%	4.42%	4.82%	5.19%	5.08%	5.10%	5.10%	5.11%	5.12%	5.13%	5.13%	5.14%	5.14%	5.15%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.42%	0.86%	1.30%	1.71%	2.10%	2.47%	2.83%	3.17%	3.48%	3.78%	4.07%	4.34%	4.59%	4.82%	5.05%	5.25%	5.45%	5.63%	5.79%	5.95%
Incremental Delivery Rate Impact Compared to Prior Year																				
Scenario 1: Expensing EEC Expenditures	9.75%	-5.60%	-0.07%	-0.05%	0.07%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%
Scenario 2: Amortizing EEC Expenditures over 5 years	1.24%	0.98%	0.96%	0.88%	0.80%	-0.25%	0.04%	-0.01%	0.01%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%
Scenario 3: Amortizing EEC Expenditures over 10 years	0.69%	0.62%	0.62%	0.57%	0.53%	0.50%	0.47%	0.43%	0.40%	0.37%	-0.11%	0.02%	0.00%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%
Scenario 4: Amortizing EEC Expenditures over 20 years	0.42%	0.44%	0.44%	0.41%	0.39%	0.37%	0.36%	0.34%	0.32%	0.30%	0.28%	0.27%	0.25%	0.24%	0.22%	0.21%	0.19%	0.18%	0.17%	0.15%

FEW EEC deferral impacts - Scenario 1: Expensing EEC Expenditures

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00%
2	Equity		40.00%	40.00%	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00%
3	STD Rate		4.50%	3.50%	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50%
4	STD %		10.08%	11.76%	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08%
5	LTD Rate		5.11%	5.11%	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11%
6	LTD %		49.92%	48.24%	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92%
7	Return on Rate Base		7.00%	6.88%	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00%
8	WACC		6.25%	6.16%	6.23% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		7,992			8,152	8,315	8,481	8,651	8,824
12	EEC Expenditures excluding Switch & Shrink (2012-2013 Expenditures assumed to amortize all in 2014; 2014 onwards included in O&M forecast)		150	121	356	344 0	373 0	374 0	377 0	390
13	EEC Switch & Shrink Expenditures		-	-	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		113	-	90	344	-	-	-	-
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		150	121	356	-	-	-	-	-
21	Tax		(38)	(30)	(92)	-	-	-	-	-
22	Net Additions	Sum of Lines 20 through 21	113	90	264	-	-	-	-	-
23	Amortization		(11)	-	(11)	(344)	-	-	-	-
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	214	90	344	-	-	-	-	-
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	163	45	217	172	-	-	-	-
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	7	2	9	7	-	-	-	-
39	Add: Amortization	-Line 23	11	-	11	344	-	-	-	-
40	Taxable Income After Tax	Sum of Lines 38 through 39	18	2	20	351	-	-	-	-
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	23	2	27	474	-	-	-	-
45										
46	Tax Expense	Line 42 x Line 44	6	1	7	123	-	-	-	-
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	344	373	374	377	390
50	Amortization	-Line 23	11	-	11	344	-	-	-	-
51	Tax Expense	Line 46	6	1	7	123	-	-	-	-
52	Earned Return	Line 26 x Line 7	11	3	15	12	-	-	-	-
53	Total Revenue Requirement	Sum of Lines 49 through 52	28	4	33	823	373	374	377	390
54	Cumulative Revenue Requirement Change vs. 2013 Approved					795	345	346	349	362
55	Forecast Delivery Margin	Line 11				8,152	8,315	8,481	8,651	8,824
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				9.75%	4.15%	4.08%	4.03%	4.10%
57	Incremental Delivery Rate Impact					9.75%	-5.60%	-0.07%	-0.05%	0.07%

	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
#	10.00%	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00% #	10.00%
#	40.00%	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00% #	40.00%
#	4.50%	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50% #	4.50%
#	10.08%	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08% #	10.08%
#	5.11%	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11% #	5.11%
#	49.92%	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92% #	49.92%
#	7.00%	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00% #	7.00%
#	6.22%	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22% #	6.22%
#	26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
	9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
0	398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
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-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
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-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
370	377	386	394	402	411	420	429	438	447	457	466	476	486	497
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
4.11%	4.11%	4.12%	4.12%	4.13%	4.14%	4.14%	4.15%	4.15%	4.16%	4.16%	4.17%	4.17%	4.18%	4.18%
0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%

FEW EEC deferral impacts - Scenario 2: Amortizing EEC Expenditures over 5 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		4.50%	3.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
4	STD %		10.08%	11.76%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%
5	LTD Rate		5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%
6	LTD %		49.92%	48.24%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%
7	Return on Rate Base		7.00%	6.88%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
8	WACC		6.25%	6.16%	6.23%	6.22%	6.22%	6.22%	6.22%	6.22%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		7,992			8,152	8,315	8,481	8,651	8,824
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 5 years beginning the following year)		150	121	356	344	373	374	377	390
13	EEC Switch & Shrink Expenditures (included in O&M)		-	-	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		113	-	90	344	530	686	788	837
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		150	121	356	344	373	374	377	390
21	Tax		(38)	(30)	(92)	(89)	(97)	(97)	(98)	(101)
22	Net Additions	Sum of Lines 20 through 21	113	90	264	255	276	277	279	289
23	Amortization		(11)	-	(11)	(69)	(120)	(175)	(230)	(286)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	214	90	344	530	686	788	837	839
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	163	45	217	437	608	737	812	838
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	7	2	9	17	24	29	32	34
39	Add: Amortization	-Line 23	11	-	11	69	120	175	230	286
40	Taxable Income After Tax	Sum of Lines 38 through 39	18	2	20	86	144	204	263	320
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	23	2	27	117	195	276	355	432
45										
46	Tax Expense	Line 42 x Line 44	6	1	7	30	51	72	92	112
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	-	-	-	-	-
50	Amortization	-Line 23	11	-	11	69	120	175	230	286
51	Tax Expense	Line 46	6	1	7	30	51	72	92	112
52	Earned Return	Line 26 x Line 7	11	3	15	31	43	52	57	59
53	Total Revenue Requirement	Sum of Lines 49 through 52	28	4	33	130	213	298	379	457
54	Cumulative Revenue Requirement Change vs. 2013 Approved					101	185	270	351	429
55	Forecast Delivery Margin	Line 11				8,152	8,315	8,481	8,651	8,824
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				1.24%	2.22%	3.18%	4.06%	4.86%
57	Incremental Delivery Rate Impact					1.24%	0.98%	0.96%	0.88%	0.80%

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%
5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%
49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%
7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%
26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
839	859	876	894	913	931	950	969	988	1,008	1,028	1,049	1,070	1,091	1,113
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
(103)	(105)	(108)	(110)	(112)	(114)	(116)	(119)	(121)	(124)	(126)	(129)	(131)	(134)	(136)
294	300	306	312	319	325	332	338	345	352	359	366	373	381	388
(275)	(283)	(288)	(294)	(300)	(306)	(313)	(319)	(325)	(332)	(338)	(345)	(352)	(359)	(366)
859	876	894	913	931	950	969	988	1,008	1,028	1,049	1,070	1,091	1,113	1,135
849	867	885	904	922	941	959	979	998	1,018	1,038	1,059	1,080	1,102	1,124
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	35	35	36	37	38	38	39	40	41	42	42	43	44	45
275	283	288	294	300	306	313	319	325	332	338	345	352	359	366
309	318	323	330	337	344	351	358	365	372	380	387	395	403	411
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
417	429	437	446	456	465	474	484	493	503	513	524	534	545	556
109	112	114	116	118	121	123	126	128	131	133	136	139	142	144
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	283	288	294	300	306	313	319	325	332	338	345	352	359	366
109	112	114	116	118	121	123	126	128	131	133	136	139	142	144
59	61	62	63	65	66	67	69	70	71	73	74	76	77	79
443	455	463	473	483	493	503	513	523	534	544	555	566	578	589
415	427	435	445	455	465	475	485	495	506	516	527	538	550	561
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
4.61%	4.65%	4.65%	4.65%	4.67%	4.68%	4.68%	4.69%	4.69%	4.70%	4.70%	4.71%	4.71%	4.72%	4.72%
-0.25%	0.04%	-0.01%	0.01%	0.02%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%

FEW EEC deferral impacts - Scenario 3: Amortizing EEC Expenditures over 10 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		4.50%	3.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
4	STD %		10.08%	11.76%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%
5	LTD Rate		5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%
6	LTD %		49.92%	48.24%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%
7	Return on Rate Base		7.00%	6.88%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
8	WACC		6.25%	6.16%	6.23%	6.22%	6.22%	6.22%	6.22%	6.22%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		7,992			8,152	8,315	8,481	8,651	8,824
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 10 years beginning the following year)		150	121	356	344	373	374	377	390
13	EEC Switch & Shrink Expenditures (included in O&M)		-	-	-	-	-	-	-	-
14										
15										
16			**2013 Approved in Rates**	**2012 Forecast**	**2013 Forecast**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**
17	**Rate Base EEC Deferral**									
18	Opening Deferral		113	-	90	344	564	780	969	1,133
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		150	121	356	344	373	374	377	390
21	Tax		(38)	(30)	(92)	(89)	(97)	(97)	(98)	(101)
22	Net Additions	Sum of Lines 20 through 21	113	90	264	255	276	277	279	289
23	Amortization		(11)	-	(11)	(34)	(60)	(87)	(115)	(143)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	214	90	344	564	780	969	1,133	1,279
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	163	45	217	454	672	875	1,051	1,206
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	7	2	9	18	27	35	42	48
39	Add: Amortization	-Line 23	11	-	11	34	60	87	115	143
40	Taxable Income After Tax	Sum of Lines 38 through 39	18	2	20	53	87	122	157	191
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	23	2	27	71	117	165	212	258
45										
46	Tax Expense	Line 42 x Line 44	6	1	7	18	30	43	55	67
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	-	-	-	-	-
50	Amortization	-Line 23	11	-	11	34	60	87	115	143
51	Tax Expense	Line 46	6	1	7	18	30	43	55	67
52	Earned Return	Line 26 x Line 7	11	3	15	32	47	61	74	84
53	Total Revenue Requirement	Sum of Lines 49 through 52	28	4	33	85	137	192	244	295
54	Cumulative Revenue Requirement Change vs. 2013 Approved					56	109	163	216	266
55	Forecast Delivery Margin	Line 11				8,152	8,315	8,481	8,651	8,824
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				0.69%	1.31%	1.93%	2.49%	3.02%
57	Incremental Delivery Rate Impact					0.69%	0.62%	0.62%	0.57%	0.53%

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%
5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%
49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%
7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%
# 26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
1,279	1,401	1,500	1,575	1,626	1,651	1,686	1,719	1,754	1,790	1,825	1,862	1,899	1,937	1,976
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
(103)	(105)	(108)	(110)	(112)	(114)	(116)	(119)	(121)	(124)	(126)	(129)	(131)	(134)	(136)
294	300	306	312	319	325	332	338	345	352	359	366	373	381	388
(172)	(201)	(231)	(262)	(293)	(291)	(298)	(303)	(309)	(316)	(322)	(329)	(335)	(342)	(349)
1,401	1,500	1,575	1,626	1,651	1,686	1,719	1,754	1,790	1,825	1,862	1,899	1,937	1,976	2,015
1,340	1,451	1,538	1,601	1,638	1,668	1,702	1,737	1,772	1,808	1,844	1,881	1,918	1,957	1,996
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	58	62	64	66	67	68	69	71	72	74	75	77	78	80
172	201	231	262	293	291	298	303	309	316	322	329	335	342	349
225	259	293	326	359	357	366	373	380	388	396	404	412	420	429
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
305	350	396	441	485	483	494	504	514	525	535	546	557	568	579
79	91	103	115	126	126	129	131	134	136	139	142	145	148	151
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
172	201	231	262	293	291	298	303	309	316	322	329	335	342	349
79	91	103	115	126	126	129	131	134	136	139	142	145	148	151
94	102	108	112	115	117	119	122	124	127	129	132	134	137	140
345	394	442	489	534	533	546	556	567	579	591	602	614	627	639
317	366	414	460	506	505	517	528	539	551	562	574	586	599	611
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
3.52%	3.98%	4.42%	4.82%	5.19%	5.08%	5.10%	5.10%	5.11%	5.12%	5.13%	5.13%	5.14%	5.14%	5.15%
0.50%	0.47%	0.43%	0.40%	0.37%	-0.11%	0.02%	0.00%	0.01%	0.01%	0.01%	0.01%	0.00%	0.00%	0.00%

FEW EEC deferral impacts - Scenario 4: Amortizing EEC Expenditures over 20 Years

Line	General Assumptions	Reference	2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
1	ROE		10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
2	Equity		40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
3	STD Rate		4.50%	3.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
4	STD %		10.08%	11.76%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%
5	LTD Rate		5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%
6	LTD %		49.92%	48.24%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%
7	Return on Rate Base		7.00%	6.88%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
8	WACC		6.25%	6.16%	6.23%	6.22%	6.22%	6.22%	6.22%	6.22%
9	Tax Rate		25.00%	25.00%	25.75%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #
10	Inflation Rate		N/A			2%	2%	2%	2%	2%
11	Delivery Margin (inflated beginning 2014)		7,992			8,152	8,315	8,481	8,651	8,824
12	EEC Expenditures excluding Switch & Shrink (all expenses amortized over 20 years beginning the following year)		150	121	356	344	373	374	377	390
13	EEC Switch & Shrink Expenditures (included in O&M)		-	-	-	-	-	-	-	-
14										
15										
16			2013 Approved in Rates	2012 Forecast	2013 Forecast	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
17	**Rate Base EEC Deferral**									
18	Opening Deferral		113	-	90	344	581	827	1,060	1,282
19	Adjustments	Transfer from non-rate base				-				
20	Gross Additions		150	121	356	344	373	374	377	390
21	Tax		(38)	(30)	(92)	(89)	(97)	(97)	(98)	(101)
22	Net Additions	Sum of Lines 20 through 21	113	90	264	255	276	277	279	289
23	Amortization		(11)	-	(11)	(17)	(30)	(44)	(58)	(72)
24	Closing Deferral	Line 18 + Line 19 + Line 22 + Line 23	214	90	344	581	827	1,060	1,282	1,499
25										
26	Rate Base	(Line 18 + Line 19 + Line 24) / 2	163	45	217	462	704	944	1,171	1,390
27										
28	**Non-Rate Base EEC Incentive Deferral**									
29	Opening Deferral		-	-	-	-	-	-	-	-
30	Adjustments	Transfer to rate base				-				
31	Gross Additions		-	-	-	-	-	-	-	-
32	Tax		-	-	-	-	-	-	-	-
33	Net Additions	Sum of Lines 31 through 32	-	-	-	-	-	-	-	-
34	AFUDC		-	-	-	-	-	-	-	-
35	Closing Deferral	Line 29 + Line 30 + Line 33 + Line 34	-	-	-	-	-	-	-	-
36										
37	**Tax Expense**									
38	Equity Return	Line 26 x Line 1 x Line 2	7	2	9	18	28	38	47	56
39	Add: Amortization	-Line 23	11	-	11	17	30	44	58	72
40	Taxable Income After Tax	Sum of Lines 38 through 39	18	2	20	36	58	81	104	127
41										
42	Tax Rate	Line 9	25.0%	25.0%	25.8%	26.0%	26.0%	26.0%	26.0%	26.0%
43										
44	Taxable Income Before Tax	Line 40 / (1 - Line 42)	23	2	27	48	78	110	141	172
45										
46	Tax Expense	Line 42 x Line 44	6	1	7	13	20	29	37	45
47										
48	**Revenue Requirement**									
49	O&M		-	-	-	-	-	-	-	-
50	Amortization	-Line 23	11	-	11	17	30	44	58	72
51	Tax Expense	Line 46	6	1	7	13	20	29	37	45
52	Earned Return	Line 26 x Line 7	11	3	15	32	49	66	82	97
53	Total Revenue Requirement	Sum of Lines 49 through 52	28	4	33	62	100	138	176	214
54	Cumulative Revenue Requirement Change vs. 2013 Approved					34	71	110	148	185
55	Forecast Delivery Margin	Line 11				8,152	8,315	8,481	8,651	8,824
56	Cumulative Delivery Rate Impact	Line 54 / Line 55				0.42%	0.86%	1.30%	1.71%	2.10%
57	Incremental Delivery Rate Impact					0.42%	0.44%	0.44%	0.41%	0.39%

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%	10.08%
5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%	5.11%
49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%	49.92%
7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%	6.22%
26.00%	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00% #	26.00%
2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast	2032 Forecast	2033 Forecast
1,499	1,707	1,907	2,097	2,279	2,451	2,613	2,766	2,909	3,042	3,164	3,276	3,377	3,467	3,545
398	406	414	422	431	439	448	457	466	475	485	495	505	515	525
(103)	(105)	(108)	(110)	(112)	(114)	(116)	(119)	(121)	(124)	(126)	(129)	(131)	(134)	(136)
294	300	306	312	319	325	332	338	345	352	359	366	373	381	388
(86)	(101)	(116)	(131)	(147)	(163)	(179)	(195)	(212)	(230)	(247)	(265)	(283)	(302)	(321)
1,707	1,907	2,097	2,279	2,451	2,613	2,766	2,909	3,042	3,164	3,276	3,377	3,467	3,545	3,613
1,603	1,807	2,002	2,188	2,365	2,532	2,690	2,837	2,975	3,103	3,220	3,326	3,422	3,506	3,579
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	72	80	88	95	101	108	113	119	124	129	133	137	140	143
86	101	116	131	147	163	179	195	212	230	247	265	283	302	321
150	173	196	219	241	264	286	309	331	354	376	398	420	442	464
26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%	26.0%
203	234	265	295	326	357	387	417	448	478	508	538	568	598	627
53	61	69	77	85	93	101	109	116	124	132	140	148	155	163
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	101	116	131	147	163	179	195	212	230	247	265	283	302	321
53	61	69	77	85	93	101	109	116	124	132	140	148	155	163
112	127	140	153	166	177	188	199	208	217	226	233	240	246	251
251	288	325	361	397	433	468	503	537	571	605	638	671	703	735
223	260	296	333	369	404	440	474	509	543	576	610	642	675	707
9,000	9,180	9,364	9,551	9,742	9,937	10,136	10,339	10,545	10,756	10,971	11,191	11,415	11,643	11,876
2.47%	2.83%	3.17%	3.48%	3.78%	4.07%	4.34%	4.59%	4.82%	5.05%	5.25%	5.45%	5.63%	5.79%	5.95%
0.37%	0.36%	0.34%	0.32%	0.30%	0.28%	0.27%	0.25%	0.24%	0.22%	0.21%	0.19%	0.18%	0.17%	0.15%

Attachment I4

PWC PROPOSAL – FEU EEC PROGRAM

www.pwc.com/ca

FortisBC Energy Efficiency and Conservation Program
Administration and Annual Review

March 25, 2013

pwc

March 25, 2013

Sarah Smith
Director, Energy Efficiency and Conservation
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Smith:

PricewaterhouseCoopers ("PwC") is pleased to provide FortisBC with our proposal for administrative and review services for the Energy Efficiency and Conservation programs based on our meetings and discussions with your team. Our proposal will clearly and concisely demonstrate our in-depth understanding of the project requirements and describe the team that we believe is ideally suited to work with you on this key initiative.

Please contact me at 604-484-3480 if you have any questions or would like to discuss the content of the proposal. We appreciate the opportunity to submit a proposal, and look forward to working with FortisBC.

Sincerely,

Ian Brown
Associate Partner
Ian.brown@ca.pwc.com

PricewaterhouseCoopers LLP Chartered Accountants
PricewaterhouseCoopers Place, 250 Howe Street, Suite 700, Vancouver, British Columbia, Canada V6C 3S7
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1. Our understanding of your needs

Our understanding of the requirements

FortisBC's Energy Efficiency and Conservation ("EEC") Program provides financial incentives for activities that aim to improve the efficiency of energy usage. Program funds are available for demand side management ("DSM") activities under a number of incentive programs targeting both residential and commercial customers.

Following an inquiry by the British Columbia Utilities Commission ("BCUC") into the practices and conduct of FortisBC in the Thermal Energy Services ("TES") markets, the BCUC has directed FortisBC to bring forward a proposal for mechanisms for approval and administration by a neutral third party of EEC funding for any activities with a TES component. FortisBC requested that PwC develop a proposal for a third-party administrative mechanism that will address BCUC's directive. PwC's proposed team has extensive experience in third-party program administration and is also currently the fairness advisor for FortisBC's Natural Gas for Transportation incentive program.

In addition to third party administration of EEC program activities, FortisBC has requested a third-party review of EEC grants involving TES components that have been awarded in the previous two years since inception of the program, and an annual review and reporting of EEC grants involving TES components on a go forward basis. The primary objective of these reviews will be to determine whether the awarded EEC grants are in line with established program guidelines and policies and that the award process was free of any bias or influence.

The following sections outline our understanding of the scope of work, our proposed approach to the administration and review of the EEC grants, and our price proposal. A summary of our corporate experience in program administration and fund management, and our work as a fairness advisor is also provided. Also, included in the appendix are detailed process diagrams, reporting templates, and resumes for key team members.

Our scope of work

The scope of work involves two components: (i) third party administration of FortisBC's EEC programs for those projects that are determined to involve a third party TES provider; and (ii) an annual review of all EEC program activities involving involving a third party TES provider completed within the past two years. The applicable TES incentive programs include: Efficient Boiler Program, Commercial Water Heater Program, and the Commercial Custom Design Programs for New Construction and Retrofit.

Our proposed approach

A proven approach to third party program administration

PwC's proposed approach to the administration of the EEC will be business-focused and is based on best practices established with over ten years of experience administering other funding programs in British Columbia and Alberta. PwC provides services for all stages of the funding program cycle, including strategic planning, project solicitation and review, through to project administration, performance evaluation and communicating program value (see Figure 1 below). PwC's administrative model is flexible, comprehensive and has been successfully adapted to a variety of program structures in BC and other Canadian provinces.

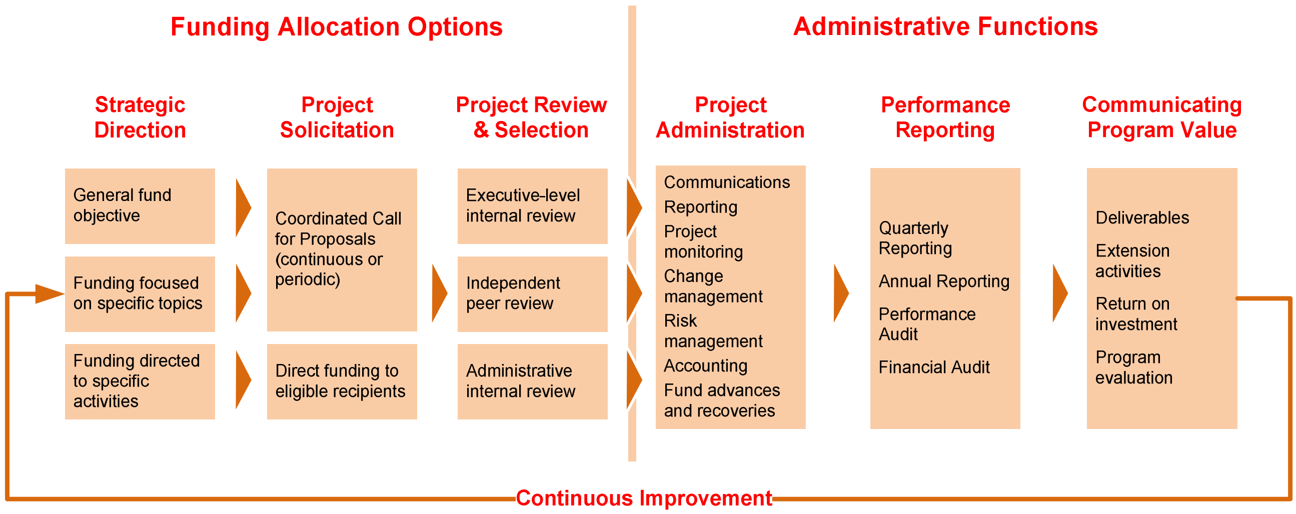


Figure 1. - PwC's approach to fund management and program administration

PwC utilizes and adapts its Fund Management Model approach in the delivery of all funding programs it administers. The model enables us to determine, in consultation with our client, the best approach to a program's delivery and administration. It is highly flexible and can be customized to capture the unique information requirements of a program. PwC also has a proprietary project information management system (IMS) that, where needed by a specific client, has provided an efficient platform for establishing project controls, change management processes and facilitating the management and disbursements of funds. The IMS also ensures decisions and correspondence are well documented and that all project and financial information is secure, yet readily accessible. Digital information security protocols employed by PwC ensure client information security, integrity and privacy requirements are met.

In consultation with FortisBC program managers, PwC has developed a proposed business process for third party administration for each of the four EEC programs involving a TES component. Detailed process diagrams illustrating the relationship, roles and flow of information for the third party administrator (PwC), FortisBC, program partners, and program participants are provided in Appendix A of this proposal. For each program, an initial step will determine whether a new application involves a third-party TES provider. Generally, this will be indicated by the Applicant on the initial application form. However, where the involvement of a third-party TES provider is revealed later in the application process, PwC will then take over the review and administration of the project from FortisBC.

As the third party administrator, PwC will complete the review and approval of the application based on the eligibility requirements of the specific program and will be responsible for determination of the incentive award amount. Except where noted, the Applicant will communicate exclusively with PwC program managers during the application review process. Generally, once a review decision has been made, PwC will notify FortisBC of the award decision, including the incentive amount and FortisBC will then execute the grant agreement (in the form of an award letter) with the participant and issue payment. The process of communication for each program is detailed in the process diagrams provided in Appendix A. The PwC "award" decision template is also provided in Appendix B.

Where applicable, PwC will also complete technical reviews of energy studies and will conduct site visits to confirm the requirements of the grant agreement have been met. Independent technical experts will be employed for these reviews where required. PwC's proposed processes are designed to be transparent and all decisions and review processes will be adequately documented such that an independent reviewer would be able to determine how our conclusions were reached.

PwC will also regularly provide program summary information to support FortisBC's budget forecasting and annual reporting requirements for the EEC programs.

Annual Program Review

PwC will conduct an annual review of EEC program activities that involve a third party TES provider. A preliminary review of all EEC program activities will be conducted initially to identify any projects involving a third party TES provider. This preliminary review will include both successful and unsuccessful applications and will consider all applications received by FortisBC within the past two years.

Based on discussions with FortisBC, we understand that for the previous two years, TES project applications have only been submitted under the Efficient Boiler Program ("EBP"). FortisBC estimates that approximately ten school districts and municipalities in British Columbia will meet the criteria to be included in this initial review. However, in subsequent years, the scope of review will include projects applications submitted under all four programs.

For grant applications determined to involve a third party TES provider, PwC's review will evaluate the application intake, review and award processes, and will focus on decision points and determination of incentive award amounts. PwC will develop standardized review protocols that will be applied to each application. Our review protocols will be designed to answer questions such as:

- Was the program advertised to ensure equal opportunity to all potential participants?
- Were program policies consistently communicated to all participants?
- Who at FortisBC was involved in the review and selection process, and was there potential for conflict of interest?

The review will rely on interviews with program staff as well as reviewing all supporting documentation (email correspondence, application forms, meeting minutes etc).

PwC will produce an annual report detailing a summary of the scope and objectives of the review, the methodologies applied, and the review conclusion. Where issues are identified, a management letter will be drafted for the project detailing relevant findings from the activities undertaken. A sample annual report template is provided in Appendix C.

2. Corporate Information Overview

A summary of our program administration experience

Since 2002, PwC's Fund Management & Program Delivery practice has successfully developed, implemented and adapted its' accounting processes and procedures for efficient and effective program administration, project management, due diligence, monitoring, risk management and timely reporting for such funding programs within BC and elsewhere in Canada. An integral part of this practice's success has been our ability to establish a clear business-focused approach to ensure that public funds directed towards investment activities are suitably managed and controlled. Our service offerings and delivery have been validated through the successful completion of both a Conflict of Interest Audit and Delivery Agreement Compliance Audit by the Internal Audit & Advisory Services Office of the Comptroller General (BC Ministry of Finance) on PwC's administration and delivery of the Forest Investment Account's Land Base Investment Program. To-date this team has overseen and delivered over $726 million in public funding across the province. Bringing this team's expertise and experience is key to our commitment to FortisBC as part of our work as an administrator and reviewer for the EEC program. Resumes for our key team members are provided in Appendix D. A brief synopsis of our program administration experience is provided below.

Land Based Investment Program

PwC has been the administrator for the Land Base Investment Program ("LBIP") on behalf of the BC Ministry of Forests, Lands and Natural Resources since 2002. During this time, PwC has delivered over $585M in project funding and administered nearly 9,300 projects. Functions undertaken by PwC include contract administration, due diligence on and approval of project proposals, monitoring of investment progress and compliance with standards, program reporting, auditing financial and performance measures, and program evaluation. PwC was successful in a re-award of the LBIP contract in 2007 and again in 2011 based on our administration performance since 2002.

Forest Science Program

Between 2003 and 2009, PwC was the administrator for the Forest Science Program ("FSP") in BC. PwC managed an annual two-stage Call for Proposals process, involving a Letter of Intent, followed by a Full Proposal. PwC conducted due diligence reviews to evaluate project methodology, sampling design, budget, and implementation. We also facilitated an independent proposal review process involving over 100 reviewers for over 300 proposals submitted annually. Additionally, PwC provided contract administration; due diligence for final project approvals; monitoring of investment progress; compliance with program requirements and project standards; program reporting; and financial and performance auditing. PwC was re-awarded an extension to the administration and delivery of the FSP in 2008 until the end of the program in June of 2009. During this time, PwC delivered $58 million in research funding and administered 1,015 projects on behalf of the Ministry of Forests, Lands and Natural Resources.

Job Opportunities Program

PwC worked with the BC Ministry of Community and Rural Development in partnership with Western Economic Diversification Canada to administer and deliver funding under the Job Opportunities Program ("JOP") in BC. As one of three Community Development Trust sub-programs, the JOP assisted unemployed resource workers all over British Columbia. PwC worked with community organizations, resource companies, and contractors to develop and undertake projects that would be beneficial to the local area while providing short-term work opportunities in or near those communities most affected in BC by the global economic downturn. PwC successfully administered and delivered the JOP from May 2008 until its conclusion in June 2011. The program, as part of the overall federal government's Community Adjustment Fund program, was identified as one of the national success stories in providing stimulus funding in the province in an efficient and effective manner while retaining and building upon existing skills to help maintain the workforce during the economic downturn. A total budget of $83.5 million was made available over the three years of the program, leading to the completion of 533 projects in the province.

We have also adapted our service offering to be the fund manager for the Climate Change Emissions Management Corporation in Alberta (current funds under management $315 million). Our BC team is currently working with the Alberta Energy Ministry to provide administrative support for their Bioenergy Producers Credit Program. For these programs, PwC has been responsible for overseeing the development and management of the business and financial systems and administrative processes. We have also overseen the implementation of projects under these programs, including contract administration and adherence to contribution agreements, verified through technical (compliance) and financial audits of selected projects.

A summary of our fairness advisor experience

Since June 2012, PwC's Fund Management & Program Delivery practice has been working with FortisBC as the fairness advisor for the Natural Gas for Transportation ("NGT") Incentive Program. As an independent third party with respect to FortisBC and the NGT Incentive Program, PwC's role as fairness advisor is to carry out an independent assessment of the NGT award program and provide advice to the FortisBC team on matters of fairness. We provide advice on matters of fairness, observe program activities, and provide an annual report on the fairness of the program activities.

PwC was awarded this work, in part, based on our Firm's previous experience acting as fairness advisor for many significant capital projects undertaken in BC and elsewhere in Canada. For example, PwC's Infrastructure and Project Finance team has acted as process and procurement advisor in relation to the following projects in BC:

- Gateway – Port Mann
- Canada Line
- Evergreen Line
- South Fraser Perimeter Road
- RCMP "E" Division
- Surrey Pretrial Facility

3. Our Price proposal

Program Administration

Our fee estimate for program administration relating to the EEC programs is presented below. This estimate assumes FortisBC will have access to our senior program management team and their supporting staff. Based on our conversations with FortisBC and our experience in delivering similar programs, the following table outlines our estimate of the level of work required for each program. This level of work may vary from year to year and also based on our team gaining an increased understanding of the workload requirements as we progress through this assignment.

Program name	Estimated Annual Total Participation	Estimated Annual Participation from TES related Projects	Annual Level of Effort per Applicant (days)	Min Annual LOE (days)	Max Annual LOE (days)
Commercial Custom Design Program - New Construction	10 to 15	2 to 5	6.5	13	33
Commercial Custom Design Program - Retrofit	25 to 35	5 to 8	12	60	96
Efficient Boiler Program	175	1 to 10	0.5	1	5
Efficient Boiler Program Right size assessment (approx 30%)			0.5	0.1	0.8
Residential New Homes Program	400	10 to 20	0.5	5	10
			Total Est. Days	79	144
			Total Estimated Annual Cost Range	**$141,300**	**$258,300**

Annual Review

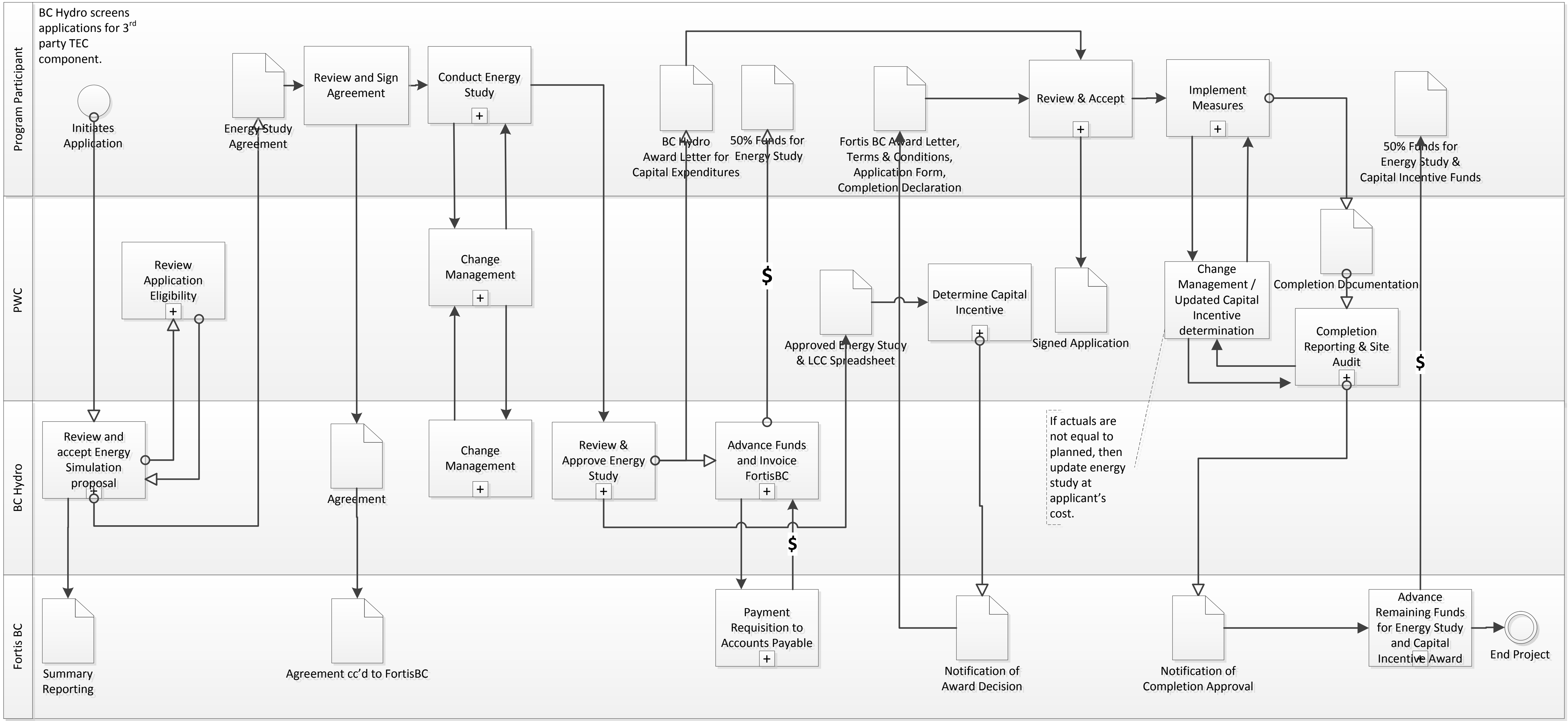
Based on discussions with FortisBC we anticipate that approximately ten school districts and municipalities in British Columbia will meet the criteria to be included in our initial review, and thus for year 1, we estimate the cost for this initial annual review will be $25,000. For the year 1 review, and in future years, our fee may vary depending on the final number of applicants to be reviewed and the availability of back-up information for each decision made.

Appendices

Appendix A– Business Process Diagrams

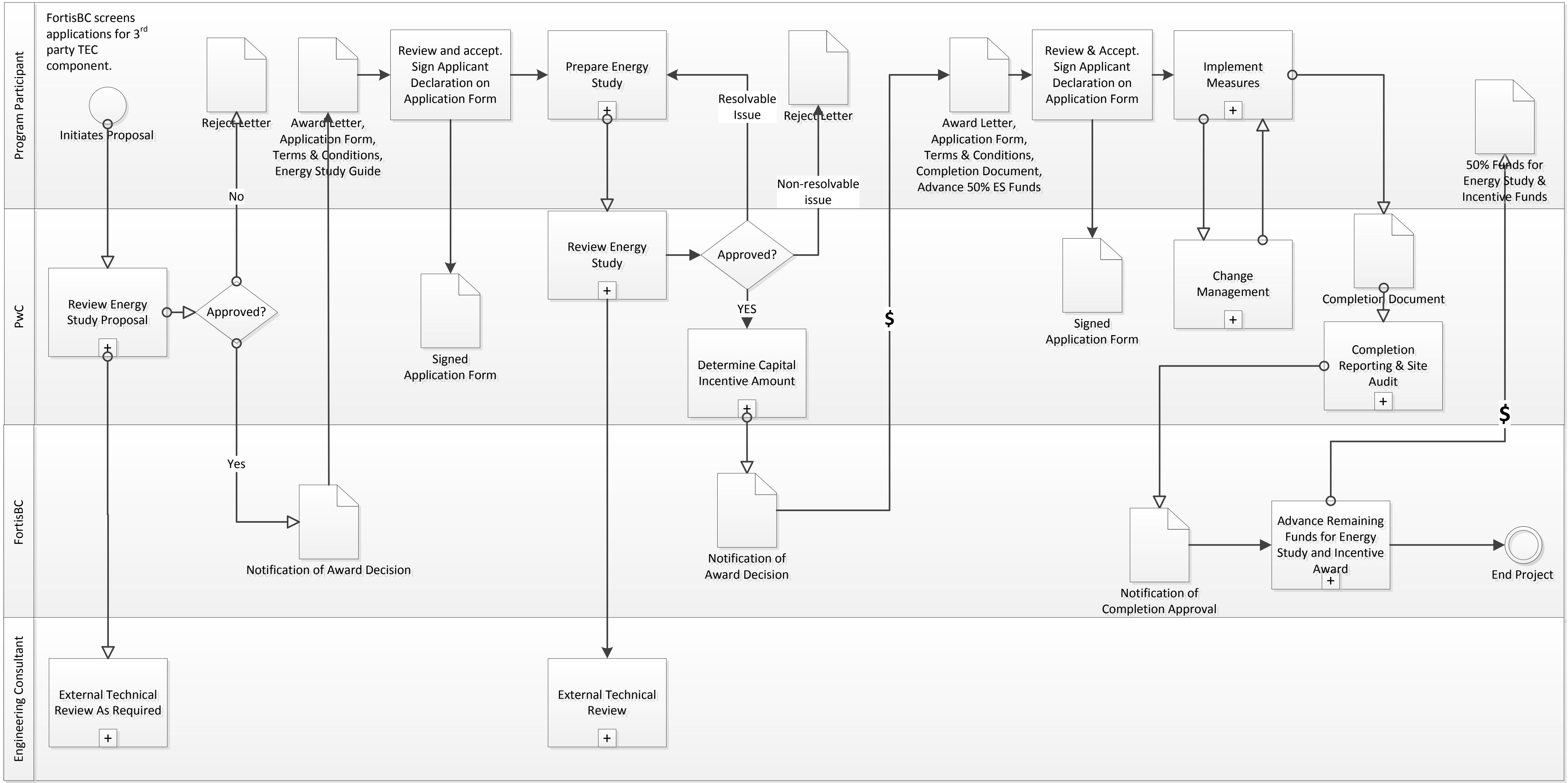
Custom Design Program – New Construction with 3rd Party TES Component

Estimated Annual Participation: 2 – 5
Estimated Annual LOE: 13-33 days



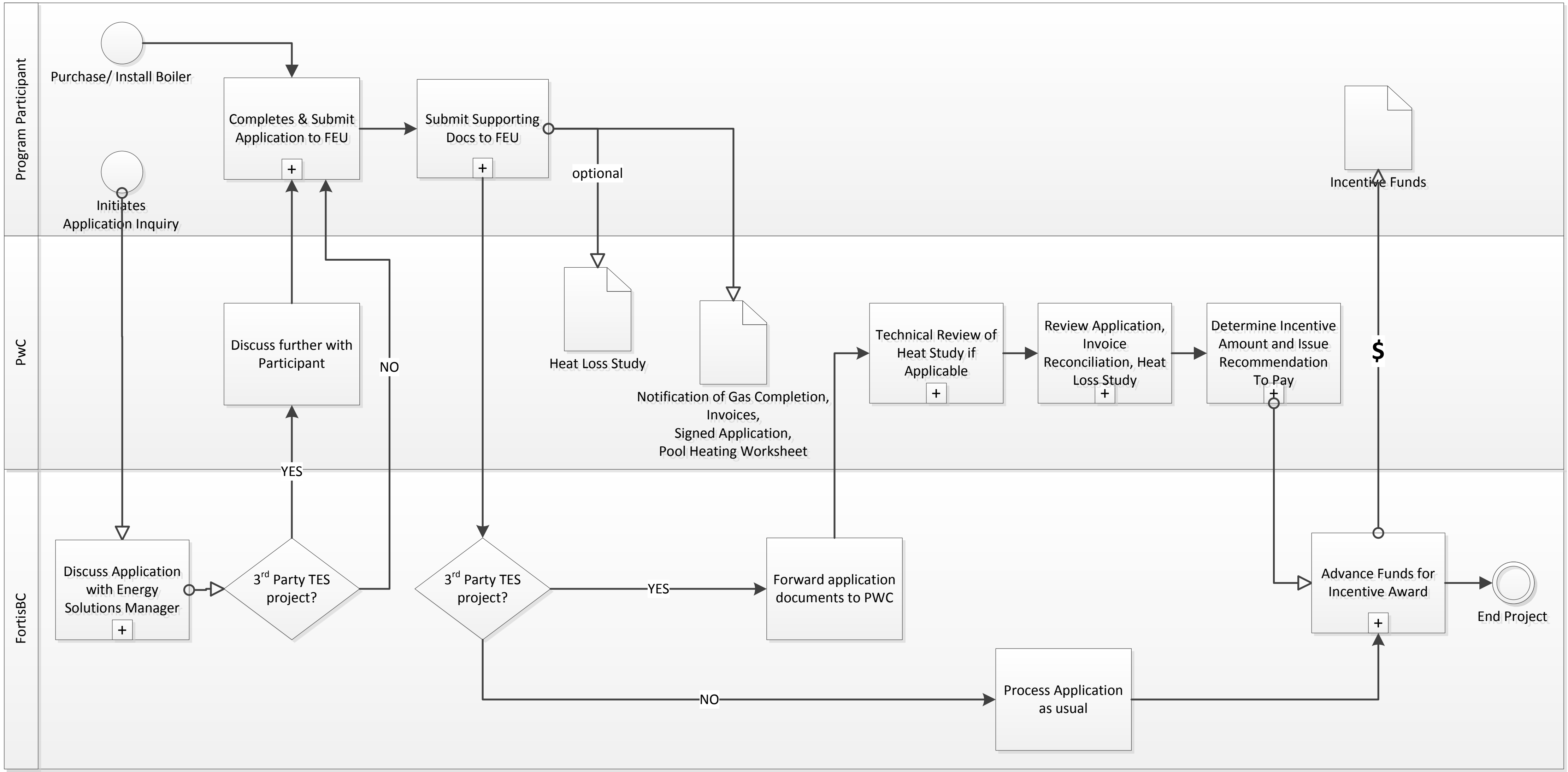
Custom Design Program – Retrofit with 3rd Party TES Component

Estimated Annual Participation: 5 - 8
Estimated Annual LOE: 60 – 96 days



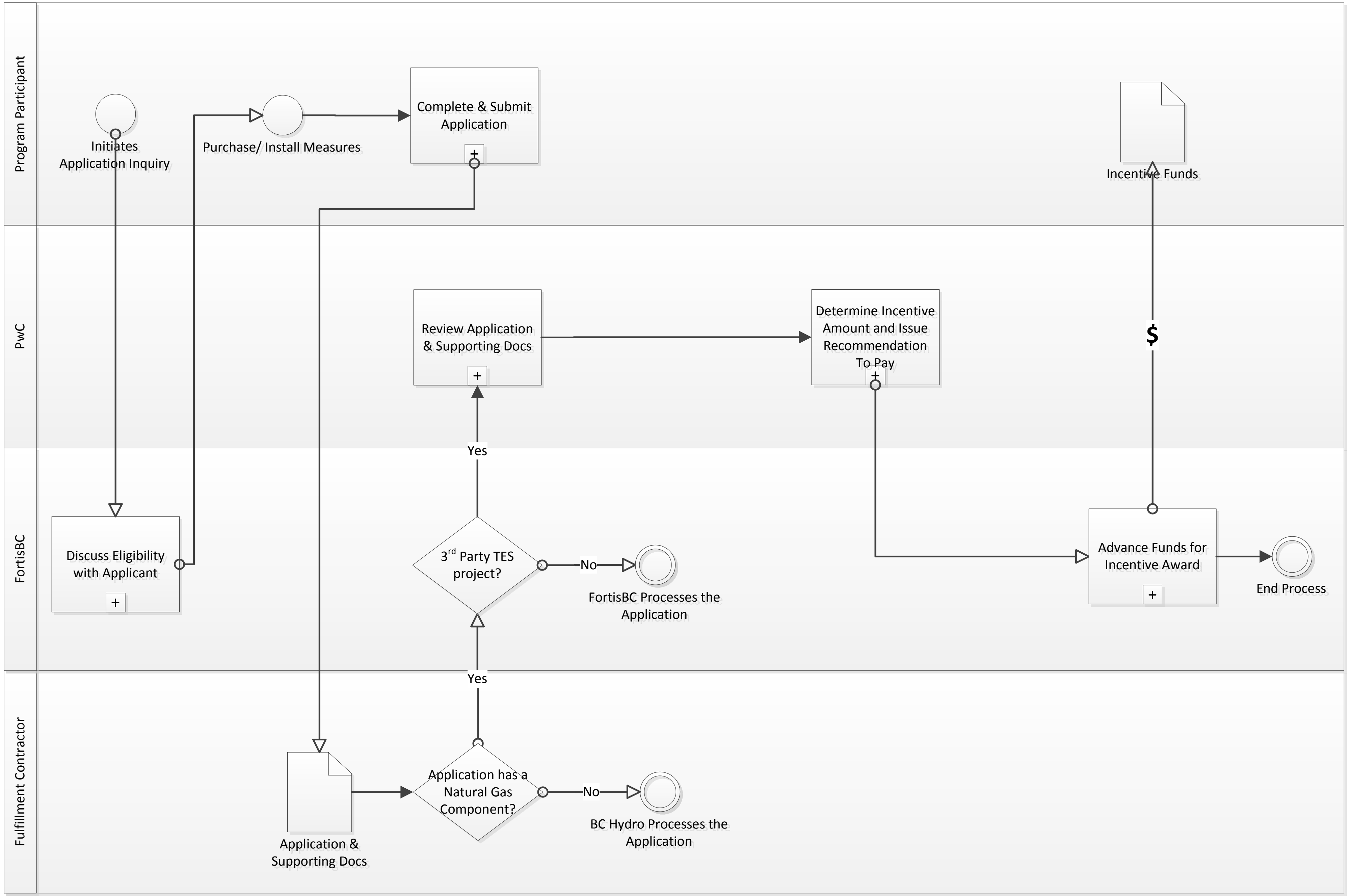
Efficient Boiler Program

Estimated Annual Participation: 1 - 10
Estimated Annual LOE: 1 – 6 days



Residential New Homes Program

Estimated Annual Participation: 10 - 20
Estimated Annual LOE: 5 – 10 days



Appendix B – Award Notification Letter Template

Month xx, 2013

Private and Confidential

Sarah Smith
Director, Energy Efficiency and Conservation
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Smith:

Re: Application review decision for FortisBC's Energy Efficiency and Conservation [insert program name] – Project [insert grant number]

PwC has completed its review of [insert applicant's name] application under the [insert program name] and has determined that the proposed project is [eligible/ not eligible] for funding under the [program name].

[If eligible for funding…]

Based on the information provided in the application and supporting documents and the funding formula for the [insert program name], PwC has calculated that the incentive award amount payable to [insert applicant's name] is:

$#####.##

[If ineligible for funding…]

The following deficiencies were noted with this application that led to our decision not to make an award:

- List of deficiencies

****

[insert name of reviewer and phone number] or I would be pleased to discuss any questions or comments, at your convenience.

Yours truly,

Ian Brown
Associate Partner

Appendix C - Annual Review Report Template

Month xx, 2013

Private and Confidential

Sarah Smith
Director, Energy Efficiency and Conservation
FortisBC
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Ms. Smith:

Re: Annual Review of FortisBC's Natural Energy Efficiency and Conservation Program

This report has been prepared in accordance with FortisBC Energy Inc. Contract Reference ##### and the Terms and Conditions contained therein. The report summarizes the results of our review of FortisBC's Energy Efficiency and Conservation Program's Projects.

Background

FortisBC's Energy Efficiency and Conservation ("EEC") Program provides financial incentives for activities that aim to improve energy use. Program funds are available for demand side management ("DSM") activities under a number of incentive programs targeting both residential and commercial customers. PricewaterhouseCoopers ("PwC") was engaged by FortisBC to complete an independent review of all Thermal Energy Services ("TES") grants that involve a third party TES provider. Our work included a preliminary review of all program activities within the last two years [insert dates of relevant EEC programs], to identify program activities involving a third party TES provider and the following grants were determined to be within the scope of our review.

[list grant numbers and names of project]

This report covers PwC's review of existing EEC grant [insert grant number] which was determined to involve a third party TES provider.

General Scope of Reviews

EEC program activities and associated administration of grants involving a third party TES provider were subject to the review. The primary review objective was to determine whether the EEC grant awarded met the established program guidelines and policies and that the award process was free of any bias or influence. PwC conducted a review of the application intake, review and selection processes, with a focus on decision points and determination of incentive award amounts. The report includes our review conclusions, a summary of the scope and objectives of the assignment, the methodologies applied and any relevant findings from the activities undertaken.

Review Conclusion

[If an issue is noted, a concise description will be provided here. It will be noted whether the finding is a material deficiency (where the deficiency is significant and negatively impacts the overall fairness or transparency of the activity), or a minor deficiency (not affecting the overall fairness or transparency of the activity).]

As indicated in the attached appendices, the following issues were identified:

- We did not encounter any matters that were considered deficient within the defined program terms and processes.
- ## issue(s) material deficiency (Appendix A)
- ## issue(s) of minor deficiency (Appendix B).

****

We thank FortisBC's personnel as well as [any other non-FortisBC person], for their cooperation and assistance during our evaluation. [insert name of reviewer and phone number] or I would be pleased to discuss any questions or comments, at your convenience.

Yours truly,

Ian Brown
Associate Partner

Appendix D - Resumes

Ian Brown, MBA, PEng

Associate Partner

T: 604 484 3480

ian.brown@ca.pwc.com

Role	Ian will have overall accountability for the success of the engagement and will work closely with the project team to provide oversight, and quality assurance for the administrative processes. Ian will be the main point of contact with FortisBC's program director with respect to award notifications and other formal correspondence.
Summary	Ian is an Associate Partner in PricewaterhouseCoopers' Fund Management and Program Delivery practice in Vancouver. He is a Professional Engineer, has a forestry degree, and has completed a Masters in Business Administration. Ian has extensive experience conducting program evaluations, administering government funding programs, conducting administrative reviews both in private sector and government organizations. Ian is an experienced and skilled auditor with extensive experience conducting contribution agreement audits, performance audits, and management system audits (ISO EMS 14001).
Education	• Bachelor of Science (Forest Engineering). University of New Brunswick. Fredericton, New Brunswick 1986 • Masters in Business Administration. Athabasca University. Athabasca, Alberta 2004 • Professional Engineer, Association of Professional Engineers & Geoscientists of BC (APEGBC)
Experience and expertise	• Fund Management and Program Administration • Project/Program Management and Evaluation • Business Transformation • Outsourcing • Engineering • Performance / Technical Auditing
Project Experience	• Administration, direction, monitoring and delivery of $85 million for the Job Opportunities Program for the Ministry of Jobs, Tourism and Innovation (formerly, the Ministry of Community & Rural Development) under the Community Development Trust • Administration, direction, monitoring and delivery of over $726 million for four programs on behalf of the BC government since 2002 for the Ministry of Forests, Lands & Natural Resource Operations • Program evaluations and monitoring of aspects of the Ministry of Energy and Mines Infrastructure Royalty Credit Program. • Administration and support services for the Alberta Department of Energy's Bioenergy Producer Credit Program (BPCP) • Review and evaluation of the online project application and reporting system for Forestry

	Innovation Investment Ltd. and Natural Resources Canada's funding programs. • Lead an engagement on behalf of the BC Ministry of Environment to evaluate funding mechanisms in use in other jurisdictions; and also to identify current BC legislation and capacity for spill prevention, response and recovery for industry sectors that produce, store or transport substantive volumes of hydrocarbons and other hazardous materials in the province. PwC was also to identify and evaluate funding options that address apparent deficiencies within BC and provide options and recommendations for a sustainable funding mechanism to support the mandates and initiatives of the MoE. • Leads the PwC team on providing "fairness advisor" services on the execution of Natural Gas Transportation Incentive Program by carrying out an independent assessment of approved and rejected projects based on decisions made by FortisBC's internal team under the program. • Lead a PwC team in conducting a performance benchmarking study for the BC Government's Wildfire Management Program • Lead a team conducting administrative and management reviews of four of BC's Ministry of Forests, Lands, and Natural Resource Operations District offices to evaluate their internal processes and procedures related to implementation of program funding
Value to you	Ian has over 26 years experience working with government, industry and as a consultant where he has specialized in project management, program monitoring, program evaluation, program administration and auditing.

Daniel O'Brien, MSc, RPBio, PMP, EMS(A)

Manager

T: (604) 484-3478

daniel.t.obrien@ca.pwc.com

Role

As the Program Manager, Dan will manage PwC's resources for the administration of FortisBC's EEC programs. Dan will also lead the annual review of EEC program activities. Dan will be the main point of contact for FortisBC's program managers and EEC program applicants. He will be readily available to program applicants to discuss queries related to program applications.

Summary

Dan is a Manager with PwC's Fund Management and Program Delivery practice in BC, where he provides consulting and administration services for government programs. He is a certified Project Management Professional, a certified Environmental Management Systems Auditor, and a Registered Professional Biologist with over fourteen years of research and consulting experience in a career focused in the resources sector.

Dan has extensive experience conducting program evaluations, administering government funding programs, as a fairness advisor, and conducting administrative reviews both in private sector and government organizations. Dan is an experienced and skilled auditor with extensive experience conducting contribution agreement audits, performance audits, and management system audits (ISO EMS 14001).

Education and Certifications

- Bachelor of Science (Biology). University of Victoria. Victoria, BC. 1999
- Masters of Science (Ecology). University of Manitoba. Winnipeg, Manitoba. 2001
- Registered Professional Biologist (#1630). College of Applied Biology, BC
- Project Management Professional (#1486201). Project Management Institute.
- Environmental Management Systems Auditor. (#115355). RABQSA International.

Industry Experience

- Program Manager responsible for the administration and audit of the Land Base Investment Program (LBIP) in British Columbia since 2007, with responsibility for the management and delivery of a portfolio of projects worth over $20 million annually
- Fairness Advisor for FortisBC's Natural Gas for Transportation Program, a five year $60 million incentive program directed to the transportation sector
- Program Manager providing administration and support servies for Alberta Energy's Bioenergy Producer Credit Program
- Auditor for Environmental Management System (ISO EMS 14001) certification audits for Manitoba Hydro and Shared Services BC
- Auditor for Sustainable Forestry Initiative (SFI) certification audits for forest companies located throughout U.S. and Canada
- Reviewed the contribution agreement providing funding from Western Economic Diversification Canada to the BC Ministry of Jobs, Tourism and Innovation for the implementation of the BC Economic Innovation Partnership Program

	• Examined legislation and funding models used in other jurisdictions to identify and evaluate the feasibility of, and provided recommendations for implementing a sustainable funding mechanism to support the BC Ministry of Environment's Environmental Emergencies Program • Conducted an independent review and evaluation of the online project application and reporting system for Forestry Innovation Investment Ltd. and Natural Resources Canada's funding programs • Conducted a performance benchmarking study for the BC Government's Wildfire Management Program • Conducted administrative and management reviews of four of BC's Ministry of Forests, Lands, and Natural Resource Operations District offices to evaluate their internal processes and procedures related to implementation of program funding
Value to you	Dan is a skilled interviewer, group facilitator, and efficient auditor, and has an in-depth understanding of business process improvement, risk assessment and project management and administration.

Value, on your terms
We focus on four areas: assurance, tax, consulting and deals services. But we don't think off-the-shelf products and services are always the way to go. How we use our knowledge and experience depends on what you want to achieve.

PwC Canada has more than 5,700 partners and staff in offices across the country. Whether you're one of our clients or one of our team members, we're focused on building deeper relationships and creating value in everything we do.

So we'll start by getting to know you. You do the talking, we'll do the listening. What you tell us will shape how we use our network of more than 180,000 people in 158 countries around the world—and their connections, contacts and expertise—***to help you create the value you're looking for.***

See www.pwc.com/ca for more information.

Creating a distinctive client experience

Communicating better helps us understand you better. It means starting with what's important to you and from there, building a stronger connection.

We recognize that value means different things to different people. For us, it means discovering what value means from *your* perspective—and then working together to achieve it. That's what our brand promise is all about: building relationships to create the value you're looking for.

Attachment I5

FURNACE REPLACEMENT PILOT AND PROGRAM

1. FURNACE REPLACEMENT PILOT AND PROGRAM

This section describes the FEU's Furnace Replacement Program piloted in 2012-13 and sets out the request for funding to continue this program which is included in section 3.4.2 of the 2014- 2018 EEC Plan (Attachment I1).

In the 2012-2013 RRA Decision, the Commission approved expenditures of $2 million for each of 2012 and 2013 for the Furnace Replacement Pilot Program. Part of the funds were to be used during the test period to develop a comprehensive program plan. The direction given to the Companies in the RRA Decision is as follows:

> *"Part of the $2 million in approved funds is to be used during the test period to develop a comprehensive program plan. The Panel expects the plan to incorporate best practices from other programs that have been run in the province and in other jurisdictions and to take into account related programs that may be offered by other utilities…the Commission Panel encourages the FEU to undertake further research, perhaps through a pilot program, to determine the most effective form of program design. This should include an examination of what level of incentive will provide the most cost-effective results, a more refined estimate of the likely take-up of the program and the optimal means of delivering the program. In addition to offering this as an in-house program, the Panel urges the FEU to consider a joint initiative with LiveSmart BC".*

In accordance with this directive, the FEU have undertaken initiatives to develop a comprehensive program plan to support funding for an ongoing 2014 – 2018 Furnace Replacement Program. To gather as much information as possible, the Furnace Replacement Pilot Program was launched September 1, 2012. The pilot was successful. Over 3,000 customers purchased furnaces within eight weeks (by October 31, 2012) and feedback from the trades was positive. The sections that follow deal with the Commission's direction in the excerpt above as to the various elements that should go into a program plan for the 2014-2018 iteration of the Furnace Replacement Program.

1.1 *SURVEY OF FURNACE EARLY REPLACEMENT PROGRAMS IN OTHER JURISDICTIONS*

The FEU have researched and incorporated best practices from their own (Terasen Gas) programs and other furnace programs that have run in the province and other jurisdictions. Since 2008, British Columbians have taken advantage of government programs such as the provincial LiveSmart BC program and the federal NRCan EcoEnergy program. The rebates ranged in value from $375 to $1,130 and when the government programs ran in parallel, homeowners could take advantage of both incentives. An overview of furnace programs in the BC market, since 2008 are presented in Table I5-1.

Table I5-1: Furnace Programs in BC Market Since 2008

	Program	Incentive Amount ($'s)
May 2008 - December 31, 2009	FortisBC (Formerly Terasen Gas) - Stand-Alone	$250
April 2007 - March, 2012	NRCan EcoENERGY Retrofit Homes Program	$375-$790
May 2008 - August 2009	LiveSmart BC	$580-$1130
April 2010 - March 2011	LiveSmart BC	$580-$1130
April 2011- March 2013	LiveSmart BC	$500 - $600

The FEU have conducted research on heating system upgrade programs across other jurisdictions in North America as summarized in Attachment I6. There are approximately 35 programs in market with furnace rebates ranging from $70 to $800 and boiler rebates ranging from $125 to $4 thousand. However, the majority of these programs are based on a calculation of incremental energy savings from a regulated baseline to a higher efficiency model in a scenario where the existing equipment is at the end of the its functional life and has failed or is about to fail, rather than through the more complex early replacement scenario where emergency replacements are not allowed in the program. These programs are more prevalent in the US where minimum efficiency standards are lower than in Canada. There are only a few examples of Early Replacement programs in market at this time. One example of early replacement is Massachusetts Saves. This boiler program is based on early replacement in which the replaced appliance must be in working order, must be greater than 30 years old, and the program is run outside of heating season. Forced hot water boiler incentives for 90 percent AFUE and greater are $3,500 if owner-occupied and $4 thousand for landlords. Ameren Illinois tops up heating system incentives for Early Replacement. They define early replacement as the replacement of an older, less efficient unit, before the unit stops working. In order to qualify the unit must be working, have an AFUE rating of 75 percent or less, or heating system must be more than 30 years old. Their incentive schedule is as follows:

Table I5-2: Example of Furnace Early Replacement Program Incentive Structure from Illinois

Ameren Illinois ActOnEnergy Heating System Rebate Program		
New Furnace AFUE Rating	**Standard Unit Rebate**	**Early Replacement Unit Rebate**
Furnace AFUE Rating of **95% or greater**	$200	$400
Furnace AFUE Rating of **97% or greater**	$300	$500
Boiler AFUE Rating of **95% or greater**	$500	$1000

Northwest Natural is also considering a low income early replacement program although they have not yet been approved by their Regulator. Union Gas is developing a business case for a Furnace Early Replacement program at this time.

1.2 SUMMARY OF KEY PROGRAM DESIGN ELEMENTS DETERMINED BY 2012 PILOT SUCCESS

In the fall of 2012, the FEU conducted a pilot program to determine operational elements for the most effective form of program design. The pilot was successful. More than 3000 furnaces were purchased within eight weeks of the September 1 launch date. The success was largely attributed to feedback obtained from industry experts at a Program Design Workshop on May 30th 2012. The group included over 35 attendees comprised of gas contractors, heating system manufacturers and distributors, associations such as the Thermal Energy Comfort Association ("TECA"), the BC Safety Authority, and government. Discussion topics were focused on obtaining feedback for program implementation that would lead to maximum participant uptake and contractor engagement. Industry experts were asked to provide background information for assumptions for cost effectiveness tests and input into best ways to estimate the remaining life of replaced furnaces, a key assumption for energy savings calculations.

Table I5-3 outlines key decisions that were made in consultation with industry experts for 2012 and 2013 pilot program implementation. This includes the level of incentive that will provide the most cost-effective results, estimates of the likely take-up of the program, optimal means of delivering the program for customer and contractor engagement and methods to ensure that the program promotes *early* replacement rather than *emergency* replacement which is in effect, free ridership.

The FEU hosted a follow-up Program Design Workshop II on January 10, 2013 to gain feedback about the 2012 pilot and ideas for 2013 pilot implementation. Some of the major changes to be implemented in the 2013 pilot include the following:

- Support for a customer pre-qualification process to reduce the number of declined customers and educate customers and contractors about program terms
- Run the program outside of heating season to increase the probability of early rather than emergency replacement
- Use ENERGY STAR directory for the qualifying products list of eligible furnaces

Key program design considerations for the 2012 pilot, 2013 pilot program enhancements and recommendations for 2014 are outlined in the table below.

Table I5-3: Summary of findings from 2012 Furnace Replacement Pilot Program, 2013 pilot program modifications and recommendations for 2014 Program Design

Program Design Element	Findings from 2012 Pilot to Inform 2014 Program Design
Customer Incentive	• 2012: $800 incentive was recommended by industry experts • TNS Consumer Research study – April, 2013 recommended leaving the rebate at $800 at which 29% of participants would upgrade. Lowering the rebate level to $500 resulted in only 11% participation. Increasing to $1000 had a minimal effect on increasing participation (33%). Increasing the rebate amount to $1250 could potentially increase participation to 41%, however research suggests that increasing program awareness of the $800 rebate may be just as effective as providing a larger incentive. • 2014 Recommendation: $800
Contractor Incentive	• 2012: $100 contractor incentive in 2012 compensated contractors for gathering substantial information about the replaced furnace. • 2013: $50 contractor incentive based on feedback from the Program Design Workshop II. • 2014 Recommendation: $50
Number of Participants	• 2012 Projected: 2,000 • 2012 Actual: 3,031 • 2012 Entrants Declined: 259 (outside program dates or other reasons for ineligibility) • 2013 Projected: a minimum of 2000 o Introducing a Pre-Qualification process that will educate customers and contractors about eligibility rules prior to their purchase thus increasing customer satisfaction by decreasing declined customers • 2014 Projected: Approximately 3,700 participants
Program Duration and Timing	• 2012: Initially announced purchase date from September 1 through December 31st or available to first 2000 applicants. However feedback from contractors indicated that the cutoff of 2,000 introduced too much uncertainty in the minds of potential participants (i.e.: if they proceeded with a replacement, would they still be in the first 2,000 and hence get a rebate). In response to this concern, the program was changed to accept all customers who purchased prior to October 31. Program was over-subscribed with a purchase cutoff date as of October 31, 2012. • 2013: Purchase date from April 22 through August 30th. Pre-qualification codes are available until July 1, with possible extension. Program running outside of heating season will promote early replacement and help contractors smooth out their annual workload and provide customers with better service and higher quality of installs. • 2014 Recommendation: April 22 through August 30
"Early" Replacement not "Emergency" Replacement	• 2012: Program terms state that furnaces had to be in working order and if Red Tagged (unsafe to operate) were not eligible. Minor repairs were allowed in order to encourage the replacement decision. Only eight per cent of participants reported repairs greater than $1000. • 2013: Customers declare in pre-qualification process that repair is less than $1000 or furnace in working order. Program runs outside of heating season. • 2014 Recommendation: Same as 2013.

Program Design Element	Findings from 2012 Pilot to Inform 2014 Program Design
Replaced Furnace	• 2012: Replaced furnaces were comprised of: 80% standard, 18% Mid and 2% boilers • Industry feedback suggested that all heating system types should be included to provide access to a greater number of customers • 2014 Recommendation: Include all natural gas heating systems over an age that will be determined in 2013 evaluation activities.
Years that purchase decision was advanced – remaining life of replaced furnace	Energy savings are based on the years that purchase decision was advanced: • Contractor feedback suggests 4.3 years remaining • Destructive testing of a sample of old furnaces will be conducted in spring of 2013 • Further analysis is being conducted on the aged profile of the installed base of furnaces as a predictor of remaining life and mortality table methodology. Preliminary results suggest a remaining life in excess of the 4.3 years noted by contractors. • Participant feedback suggests that in absence of the rebate program, 80% would wait until it stopped working, 17% would have it repaired, and 2% would have used another heating appliance such as a fireplace.
Eligible Products Directory	• 2012: FEU chose a minimum efficiency standard of 0.95 AFUE based on the Natural Resources Canada directory. Since ENERGY STAR qualifications were updated in February 2012, it was challenging to obtain the most comprehensive list of ENERGY STAR qualified products for the 2012 pilot. • 2013: Use the Natural Resources Canada ENERGY STAR directory in conjunction with the US ENERGY STAR directory recommended by industry experts. ENERGY STAR minimum efficiency standards at the time of writing are 0.95 AFUE. • 2014 Recommendation: Use the current US ENERGY STAR directory at the time of program launch to transition the market to increased efficiency standards.
Communications Initiatives	• 2012 Customer: FortisBC channels including fortisbc.com, the Conserver and a modest media buy, co-marketing partnerships with manufacturers, retailers, contractor program members • 2012 Contractor: Email to FortisBC Contractor Program members • 2013 Customer: Same as 2012 but a May bill insert lists the program and notifies all customers of the July 1 pre-qualification deadline. • 2013 Contractor: Email to FortisBC Contractor Program members, Mail-out to all BCSA gas contractors, Spring Contractor Newsletter • 2014 Customer: FortisBC channels including fortisbc.com, the Conserver and a modest media buy, co-marketing partnerships with manufacturers, retailers, contractor program members, bill insert if available • 2014 Contractor: Email to FortisBC Contractor Program members, Mail-out to all BCSA gas contractors, Spring Contractor Newsletter

Program Design Element	Findings from 2012 Pilot to Inform 2014 Program Design
LiveSmart BC	• 2012: $800 FEU pilot rebate was stand-alone program and customers could take advantage of both FEU and $600 LiveSmartBC rebate. There was a spike in LiveSmart BC program entrants during this time. • 2013: MEMNG incentive funding is cut for April 2013 due to budget restraints and uncertainties with a new government's fiscal priorities. FEU's budget limitations are such that the FEU cannot fully fund the LiveSmart BC furnace offer. • NRCan EcoENERGY program funding for incentives is unpredictable and now out of the market • 2013: Analysis is under way to determine if energy savings warrant the inclusion of furnaces in a LiveSmart BC Deep Retrofit Champion Bonus • 2014 Recommendation: If cost effective, include heating systems in a Deep Retrofit Champion Bonus in an ongoing provincial collaborative home performance programs. This will limit the financial exposure, promote deep retrofits for enhanced energy savings, and allow the early replacement program to run outside the heating system. Please refer to Section 3.4.2 in 2014-2018 EEC Plan for further details.
Product Stewardship	• 2012: Not required based on industry feedback • Contractor feedback on application form regarding replaced furnace disposal suggests that 95% of the replaced furnaces were recycled. • 2014 Recommendation: Continue to monitor product stewardship and support the trades on education initiatives

Discussions with industry experts on the installed furnace base, market intelligence and analysis of program participation data provided the basis of assumptions used in cost-effectiveness tests. The following table provides a summary of the inputs for cost-effectiveness. Further information and sources are detailed in the 2014-2018 EEC Plan (Attachment I1 - Section 3.4.2).

Table I5-4: Summary of findings from 2012 Furnace Replacement Pilot Program to inform cost-effectiveness tests

Assumptions for Cost Effectiveness Tests	Findings from 2012 Pilot Results and Discussions with Industry Experts
Energy savings estimates	• Standard – 10.0 GJs • Mid Efficiency – 5.5 GJs • Boilers – 8.8 GJs
Incremental costs	• Furnace - $1,597 • Boiler - $3,315
Measure Life	• 18 years
Free Rider Rates	• 8% based on participants with repairs greater than $1000
Spillover	• FEU looking into spillover methodology for future program development
TRC	• 2014 - 2018 EEC Plan forecast: 0.5
MTRC	• 2014 - 2018 EEC Plan forecast: 1.4

1.3 PROGRAM BUDGET

The following table provides an overview of 2012 pilot program actual spend, 2013 pilot program forecasted spend and forecasted annual spend for 2014 through 2018.

Table I5-5: Annual forecasted program expenditures for Furnace Replacement Pilot and Program

	2012 Pilot (Actual)	2013 Pilot (Forecast)	2014-2018 (Annual Forecast)
Incentives			
Number of Participants	3,031	2,080	3,925
Customer Incentives	$2,424,800	$1,664,000	$3,140,000
Non-Incentive Expenditures			
Contractor Incentives	$231,900	$83,000	$157,000
Program Development	$46,445	$40,000	-
Communications	$39,509	$40,000	$49,000
Administration	$24,026	$50,000	$100,000
Evaluation	$11,906	$125,000	$49,000
Total	**$2,778,586**	**$2,002,000**	**$3,495,000**

1.4 PROGRAM EVALUATION

The FEU are conducting a number of Process and Impact evaluation projects to validate cost benefit test assumptions and obtain feedback for effective program implementation. These include the following:

- A Customer Satisfaction[1] survey was included with the rebate cheque. 91 percent of customers rated their overall satisfaction of the program as 8, 9 or 10 out of 10. 88 percent of customers were highly satisfied with their gas contractors. Satisfaction was lower for speed of receiving rebates (70 percent) and program deadlines (64 percent).
- In-depth customer and contractor feedback evaluation is being conducted in May/June 2013. Participants will be included in an impact evaluation study and billing analysis in 2014.
- The FEU will be inspecting the quality of installation of a random sample of 50 furnaces in the fall of 2013. Installation quality will be correlated with contractor certification the

[1] 2012 Furnace Replacement Pilot Program Customer Satisfaction Survey, Ipsos Reid, February 2013

results of which will inform the need for accreditation in the HVAC industry. Installation quality will also be correlated with energy savings realized in the 2014 billing analysis.

- The FEU will be conducting destructive testing on a small sample of 10 replaced furnaces as a preliminary study to measure remaining life of replaced furnaces and to determine if a visual inspection system can be developed for contractors to estimate remaining life in the 2014 program.

The 2014-2018 Furnace Replacement Program will provide value to customers and the trades by encouraging customers to replace their furnaces at least 4.3 years earlier than they would have in the absence of the incentive. The province of BC has over 500,000 standard and mid-efficiency furnaces and the lowest penetration of high efficiency furnaces than any province in Canada. The program is forecasted to have a TRC of 0.5 and an MTRC of 1.4. In the 2010 CPR, this program provided 51 percent of most likely achievable energy savings potential in the Residential Sector.

FEU requests an annual program budget of $3.5 Million for incentives for about 4,000 participants in a program that runs outside the heating season. Over five years the program will generate over 30,000 GJS of annual savings and 1.5 Million GJs of net savings over the lifetime of the appliance. The FEU are determining how or if heating systems can be included in a deep retrofit champion bonus which will be a measure in the Energy Efficient Home Performance program, a collaboration with government and electric utilities that will essentially be a 2014 version of LiveSmart BC. For further details on the Furnace Replacement 2014-2018 Program Design please refer to Section 3.4.2 in 2014-2018 EEC Report.

Attachment I6

SUMMARY RESIDENTIAL HEATING SYSTEM PROGRAMS IN NORTH AMERICAN JURISDICTIONS

Summary of Residential Heating System programs in North American Jurisdictions

Utility	State/ Province	Program	Incentives
Early Replacement Programs			
Ameren	**IL**	Heating and A/C Rebates - Early Replacement qualifications: Replacement of a working unit, furnace or boiler with an AFUE of 75% or less, or at least 30 years old. Existing unit must be deemed in working condition by Program Ally. Existing and new unit must be removed and installed by Program ally.	Standard Replacement with 95% AFUE: $200 Standard Replacement with 97%+AFUE: $300 Standard Replacement Boiler with 95%+AFUE:$500. Early Replacement with 95% AFUE:$400 Early Replacement with 97%+AFUE: $500 Early Replacement Boiler with 95%+AFUE: $1000
MassSaves - all natural gas utilities in Massachusetts	MA	Boiler Rebates - Early Replacement qualifications: Boiler must be 30 or more years of age and in working condition Program is run from May 1 to August 31, outside of heating season. Requires a home energy assessment (free). Savings based on 10 year replacement advancement.	Forced Hot Water Boiler - 90%+ AFUE:$3500/$4000 per landlords Steam Boiler 82%+AFUE:$1900
Heating System Replacement Programs			
PSNC Energy	NC	Appliance Rebates	Gas Furnace AFUE 90% or higher - $100
Puget Sound Energy	WA	Boiler Rebate	ENERGY STAR qualified natural gas boiler with 95% AFUE rating or better - $350
National Grid	RI	Energy Star Natural Gas Equipment Rebates	ENERGY STAR gas boilers (90% AFUE) - $1,000; or ENERGY STAR gas boilers (85% AFUE) - $500; electronic ignition gas steam boilers (82% AFUE) - $200 ECM Motor gas furnaces (92% AFUE) - $400; gas furnaces (92% AFUE) - $100
Energy Trust of Oregon, Northwest Natural Gas	OR, WA	Gas Boiler Rebate Program	Gas boiler AFUE 88% or higher - up to $200; Natural gas furnace at least 90% AFUE (WA Customers only) - $100
Consumers Energy	MI	Heating & Cooling Rebates - Residential	Gas Furnace AFUE 94% or higher - $400; Boiler AFUE 90% or higher - $1,000
Minnesota Energy Resources	MN	Heating System Rebate	Gas Furnace 92% AFUE - $250; Gas Furnace 95% AFUE - $350; Gas Furnace for Mobile Homes 92% AFUE - $200; Gas Boiler 90% AFUE - $200
Xcel Energy	MN	Home Performance with ENERGY STAR	Furnace AFUE 92%-94% - $70; Furnace AFUE 96% - $325; Boiler AFUE 84% - $125
Alliant Energy	IA	New Home Construction	Alliant Energy Builder Option Package - Heating and cooling customers - $2,000 Heating only customers - $1,400; Advanced Builder Option Package (Requires a HERS rating) - Heating and cooling customers - $2,800 Heating only customers - $1,960 ENERGY STAR Qualified Home (Requires a HERS rating) - Heating and cooling customers - $3,500 Heating only customers - $2,450 (Eligible measures include: natural gas, forced air furnaces 92% AFUE or better, and natural gas, boilers90% AFUE or better)
Vectren Energy Delivery	OH	Appliance Rebates Program - Residential	Natural Gas furnace must have AFUE rating of at least 95% - $300; Residential boiler must have an AFUE rating of at least 90%. Primary use must be for space heating - $500
Peoples Gas (FL)	FL	Conservation Rebates	Central heating or wall furnace (3): Replace Electric with gas $725; Replace gas with gas - $500; Replace oil with gas - up to $330
NIPSCO	IN	Energy Efficiency Rebate Program	Natural gas boiler at least 95%/90% AFUE, must use natural gas for space heat, boiler must have a modulating burner and included outdoor air temperature reset control - $450/$300 per unit . Natural gas Furnace with ECM at least 95% AFUE - $300/$200 without ECM per unit; Natural gas furnace at least 92% AFUE, must be primary heat source and sealed combustion - $150 per unit.
Pacific Gas and Electric	CA	Energy Efficiency Rebates for Your Home	Central Natural Gas Furnace 94%–95.9%/96% or greater AFUE - $150/$250unit. Central Natural Gas Furnace 94%–95.9% AFUE with built-in VSM CZ restrictions apply -$200/unit; Central Natural Gas Furnace 96% AFUE or greater with built-in VSM CZ restrictions apply-$300/unit
Southwest Gas	NV	Energy Efficiency Rebates For Your Home	Natural Gas Furnace (Northern NV only) AFUE at least 95% - $300-$500
Laclede Gas	MO	EnergyWise Furnace Financing Program	Up to $10,000 financing per heating system, including some additional appliances, that customer must pay back on monthly gas bill.
Puget Sound Energy	WA	Furnace Rebate	ENERGY STAR qualified natural gas furnace at least 95% AFUE - $250
Southwest Gas	NV	Furnace Rebate	Natural gas furnace at least 92/95/97% AFUE - $300/$400/$450
DTE Energy	MI, OH	Furnace Rebate Program	Natural gas furnace 95% AFUE - $400; Natural gas boiler 92% AFUE - $450
Gaz Métro	QC	Furnace Replacement Program	Natural gas warm air heating system - $200;
Consumers Energy	MI	Heating & Cooling Rebates - Residential	Natural gas furnace at least 94% AFUE - $400; Natural gas boiler at least 90% AFUE - $1,000
Baltimore Gas & Electric	MD	Heating and Cooling program	ENERGY STAR Natural gas furnace at least 92% AFUE with ECM - $300; Natural gas furnace at least 92% AFUE with quality installation - $400
Xcel Energy	CO	Heating Rebates	Natural gas furnace at least 92/94% AFUE - $80/$120; Natural gas boiler 85% AFUE - $100
Minnesota Energy Resources	MN	Heating System Rebate	Natural gas furnace 92/95% AFUE - $250/$350; gas furnace for mobile homes 92% AFUE - $200; Natural gas boiler 90% AFUE - $200; Integrated natural gas and water heating system 90% CAE - $250
Alliant Energy	IA	Heating, Cooling & Water Heating	Natural gas boiler 85-89% AFUE - $150, 90% or greater - $400; Natural gas furnace 92-93% AFUE - $250, 94-95% AFUE - $325, 96% AFUE or greater - $400
Avista Utilities	WA, ID	High Efficiency Equipment Rebates	Natural gas furnace or boiler at least 90% AFUE - $400
Connecticut Utilities (Group)	CT	High Efficiency Furnace and Natural Gas Boiler Rebate	Natural gas furnace rated 95% AFUE with air handler performance level EAE4 less than or equal to 2% - $600; Natural gas boiler rated 90% AFUE with temperature reset or purge control - $750
Nicor Gas	IL	High Efficiency Furnace Rebates	Natural gas furnace at least 92/95/97% AFUE - $200/$250/$500; natural gas ENERGY STAR boiler at least 90/95% AFUE - $350/$450
Columbia Gas, Gas Networks, MassSave, NSTAR, National Grid, Unitil	MA	High Efficiency Home Heating & Water Heating Rebate	Natural gas furnace at least 94/96% AFUE with ECM or listed with Gas Networks - $500/$800; Natural gas boiler at least 90/96% AFUE %1,000/$1,500; integrated condensing boiler unit with DHW at leats 90% AFUE - $1,200
Xcel Energy	MN	Home Performance with ENERGY STAR	Natural gas furnace 92-94% AFUE $70, 96% AFUE - $325, Energy Audit required
Consumers Energy	MI	Home Performance with ENERGY STAR - Residential	Gas only customers: Natural gas furnace at least 94% AFUE - $500; Natural gas boiler at least 90% AFUE -$2000
Atmos Energy	KY	Kentucky High Efficiency Equipment Rebate	Natural gas furnace 90-93% AFUE/94-95% AFUE/96% AFUE or greater, 30,000 BTU or higher - $250/$325/$400; Natural gas boiler at least 855 AFUE - $250
Texas Gas Service	TX	Natural Gas Furnace	Natural gas furnace at least 80% AFUE - $75
Philadelphia Gas Works	PA	Residential Heating Equipment Rebates	Natural gas furnace at least 94% AFUE - $500; natural gas boiler at least 94% AFUE - $2000
SaskEnergy & SaskPower	SK	Saskatchewan EnerGuide for Houses Program	Natural gas ENERGY STAR rated heating system, pre and post-retrofit evaluation required.

Source: Esource Inquiry and Personal Communications with Utility Representatives

Attachment I7

FEU EEC 5 YR EVALUATION PLAN 2014-2018

EEC Evaluation Plan

2014-2018

May 2013

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1. INTRODUCTION

This EEC Evaluation Plan covers all of the FortisBC Energy Utilities (FEU), including FEI (Mainland), FEVI (Vancouver Island), and FEW (Whistler), (collectively the FEU or the Companies). It presents the studies and timing for the Companies' Evaluation, Measurement & Verification (EM&V) activities through the FEU 2014-2018 RRA test period. These activities are aligned with the 2014-2018 EEC Plan. As with the EEC Plan, the Evaluation Plan may be adjusted during the test period in consideration of changes in market conditions and other factors that can impact the EEC Plan, as well as the feedback received from EM&V activities throughout the test period. The Evaluation Plan has been prepared in consideration of the draft EM&V Framework submitted as an Appendix to the 2014-2018 RRA.

1.1 *EVALUATION, MEASUREMENT & VERIFICATION*

EM&V activities are split between the evaluation activities, and the measurement and verification activities. Evaluation activities[1] are conducted to look at a program as a whole to determine its effectiveness. The timing of evaluation activities vary depending on the program's progress, acceptance and objectives. The scope and cost of evaluation studies should be practical and feasible within the confines of resources and time available. Evaluation study objectives should align with the program's objectives. Typically, evaluation activities can commence after the program has been in the market for a minimum of 1 year or covers a full heating season. The evaluation activities are focused on identifying energy savings, assessing participant awareness and satisfaction, confirming research results, and providing feedback for program improvements and implementation.

Measurement and Verification (M&V) studies are conducted mainly to assess pilot programs, demonstration projects, and custom programs. M&V activities use measurement technologies and engineering techniques to identify the energy savings that result from an Energy Conservation Measure (ECM). The Companies' M&V studies adhere to the IPMVP[2] protocol and industry best practices to assess the actual savings attributable to the implementation of the new ECM. These activities require a greater allocation of the overall program budget than other evaluation activities do since M&V studies rely on real-time monitoring of each measure being studied and are therefore more resource intensive.

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[1] Types of evaluation studies include; Communications which focus on advertising and media outreach, Process where surveys and interviews are used to assess customer satisfaction and program success, Impact evaluations to measure the achieved energy savings attributable from the program, and Measurement & Verification activities to monitor real time energy savings associated with energy conservation measures

[2] International Performance Measurement and Verification Protocol. Concepts and Options for Determining Energy and Water Savings. Prepared by the Efficiency Valuation Organization. www.evo-world.org. January 2012.

1.2 *EVALUATION PLAN*

Table I7-1 provides a list of programs and pilot studies currently planned for evaluation from 2014 to 2018. The Evaluation Plan allows for variation in the proposed activities and budget. The extent and detail of the evaluation activities presented in the Evaluation Plan is subject to the availability of the resources, timing and budget.

Overall expenditures for the programs have been reported in Section 2 of the 2014-2018 EEC Plan, but are reported here in order to provide an easy-to-view summary of the evaluation expenditure and the 5 Year Evaluation Plan. Included in the table is: a list all proposed evaluation activities for 2014-2018; the Program Area each activity occurred in; the general type of evaluation activity undertaken; the Companies' proposed 5 year budget; and a proposed timeline on each activity. The total proposed expenditure for program evaluation and M&V activities to be conducted from 2014 to 2018 is approximately $7,404 thousand. The proposed budget aligns with the Companies EM&V Framework and general industry practice[3] for budget spending on EM&V activities. The evaluation budget shown in Table I7-1 represents 4.1 percent of the Companies' total EEC portfolio expenditure.

[3] California Evaluation Framework. June 2004. TecMarket Works.

Table I7-1: FEU Evaluation Plan for 2014-2018

FEU Evaluation Plan for 2014-2018							
Program/Pilot Name	**Program Area**	**Service Region**	**Type of Evaluation or Activities**	**Years the program has been running**	**Proposed Evaluation Partnership**	**Proposed 5 Year Budget (000's)**	**Proposed Timeline**
Space Heat Program	Commercial	FEU	Impact & Process	9	None	$174	2015 to conduct process & impact evaluation
Water Heating Program	Commercial	FEU	Impact & Process	2.5	None	$117	2015 to conduct process & impact evaluation
Commercial Food Service Program	Commercial	FEU	Impact & Process	1	None	$150	2016 to conduct process & impact evaluation
Customer Equipment Upgrade Program	Commercial	FEU	Impact & Process	1	BCHydro, FEU and FBC	$131	2015 to conduct process & impact evaluation
EnerTracker Program	Commercial	FEU	Impact & Process	New	None	$52	2014 to conduct process evaluation. 2015 to conduct process & impact evaluation for sample of participants from year 1&2
Continuous Optimization Program	Commercial	FEU	Impact & Process	New	BCHydro	$74	2015 to conduct process & impact evaluation.
Commercial Energy Assessment Program	Commercial	FEU	Impact & Process	12	None	$92	2014/2015 to conduct process evaluation. 2016 to conduct impact evaluation
Energy Specialist Program	Commercial	FEU	Impact & Process	2	None	$612	Process evaluation and Energy Savings Audits to be conducted annually
Mechanical Insulation Pilot	Commercial	FEI	Measurement & Verification	New	None	$10	2015 - M&V completion
Industrial Optimization Program	Industrial	FEU	Measurement & Verification	1	None	$743	M&V will be conducted as projects and programs start
Specialized Industrial Process Technology Program	Industrial	FEU	Measurement & Verification	New	None	$135	M&V will be conducted as projects and programs start
Condensing Unit Heater Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	1	None	$75	2014 - M&V start. M&V completion by 2016.
Radiant Tube Heater Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	2	None	$75	2014 - M&V start. M&V completion by 2016
Recirculating Demand Control Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$180	2014 - M&V start. M&V completion by 2016
Combination Units Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$128	2014 - M&V start. M&V completion by 2016

Table I7-1: FEU Evaluation Plan for 2014-2018 (continued)

FEU Evaluation Plan for 2014-2018

Program/Pilot Name	Program Area	Service Region	Type of Evaluation or Activities	Years the program has been running	Proposed Evaluation Partnership	Proposed 5 Year Budget (000's)	Proposed Timeline
Ozone Commercial Laundry Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$135	2015 - M&V start. M&V completion by 2017
De-aereator Vent Steam Recovery Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$94	2015 - M&V start. M&V completion by 2017
Residential HVAC Zoning Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$90	2015 - M&V start. M&V completion by 2017
Thermal Bridging Pilot	Innovative Technologies	FEI	Measurement & Verification	New	None	$51	2016 - M&V start. M&V completion by 2018
Water Spray Kiln Misting System Demonstration Project	Innovative Technologies	FEI	Measurement & Verification	New	None	$63	2016 - M&V start. M&V completion by 2018
Occupancy Sensor MURBs Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$49	2016 - M&V start. M&V completion by 2018
Ice Rink Efficiency Pilot	Innovative Technologies	FEI	Measurement & Verification	New	None	$57	2017 - M&V start. M&V completion by 2019
Air Curtain Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$58	2017 - M&V start. M&V completion by 2019
Transpired Air Collector Pilot	Innovative Technologies	FEI	Measurement & Verification	New	None	$106	2017 - M&V start. M&V completion by 2019.
Ceramic Manufacturing Microwave Assist Technology Pilot	Innovative Technologies	FEI	Measurement & Verification	New	None	$96	2018 - M&V start. M&V completion by 2020
Catalytic Radiant Burner Pilot	Innovative Technologies	FEI	Measurement & Verification	New	None	$55	2018 - M&V start. M&V completion by 2020
Heat Reflector Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$75	2018 - M&V start. M&V completion by 2020
Residential High Efficiency Water Heater Pilot (0.80 Pilot)	Innovative Technologies	FEI & FEVI	Measurement & Verification	2	Canadian Gas Association, Natural Gas Technology Centre & other utilities	$9	Q1, 2014 - M&V completion
ENERGY STAR © 0.67 Storage Tank Water Heater Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	1	None	$3	July 2014 - M&V completion

Table I7-1: FEU Evaluation Plan for 2014-2018 (continued)

FEU Evaluation Plan for 2014-2018

Program/Pilot Name	Program Area	Service Region	Type of Evaluation or Activities	Years the program has been running	Proposed Evaluation Partnership	Proposed 5 Year Budget (000's)	Proposed Timeline
Condensing Gas-Fired Ventilation Unit Pilot	Innovative Technologies	FEI & FEVI	Measurement & Verification	New	None	$20	2015 - M&V completion
Fireplace Inserts Pilot	Innovative Technologies	FEI	Measurement & Verification	New	None	$3	2015 - M&V completion
City of Vancouver Green MURB Pilot	Innovative Technologies	FEI	Measurement & Verification	New	City of Vancouver	$17	2015 - M&V completion
Kiln Control Pilot	Innovative Technologies	FEI	Measurement & Verification	1	BCHydro	$3	2014 - M&V completion
Residential Education	Conservation Education and Outreach	FEI & FEVI	Process & Communications	Ongoing	None	$495	Ongoing program tracking, participant awareness, advertisement awareness and qualitative measures to be conducted to assess programs
Commercial Education	Conservation Education and Outreach	FEU	Process & Communications	Ongoing	None	$225	Ongoing program tracking, participant awareness, advertisement awareness and qualitative measures to be conducted to assess programs
School Education	Conservation Education and Outreach	FEU	Process & Communications	Ongoing	None	$360	Ongoing program tracking, participant awareness, advertisement awareness and qualitative measures to be conducted to assess programs
Energy Savings Kit	Conservation for Affordable Housing	FEI & FEVI	Process	2	BC Hydro	$6	2014 participant survey to assess savings.
Energy Conservation Assistance Program	Conservation for Affordable Housing	FEI & FEVI	Process	1	BC Hydro	$124	Program launched in 2012. 2014 to conduct evaluation to assess program uptake and energy savings results
REnEW	Conservation for Affordable Housing	FEI & FEVI	Process	3	None	$20	Reports and Participant Tracking to be conducted on an annual basis to provide program feedback

Table I7-1: FEU Evaluation Plan for 2014-2018 (continued)

FEU Evaluation Plan for 2014-2018							
Program/Pilot Name	**Program Area**	**Service Region**	**Type of Evaluation or Activities**	**Years the program has been running**	**Proposed Evaluation Partnership**	**Proposed 5 Year Budget (000's)**	**Proposed Timeline**
Low Income Boiler Top-Ups	Conservation for Affordable Housing	FEI & FEVI	Process	New	BC Housing, BCNPHA, other non-profit housing societies	$1	Commercial Space Heat Program Evaluation in 2015 to support the Low Income Boiler Top-Ups program savings
Low Income Water Heater Top-Ups	Conservation for Affordable Housing	FEI & FEVI	Process	New	BC Housing, BCNPHA, other non-profit housing societies	$1	Commercial Water Heating Program Evaluation in 2015 to support the Low Income Water Heater Top-Ups program savings.
Non-Profit Custom Program	Conservation for Affordable Housing	FEI & FEVI	Process	New	None	$27	Energy studies to provide 3rd party validation on the program.
Energy Efficient Home Performance Program	Residential	FEU	Impact & Process	4	BC Hydro, PowerSense, Municipal, Provincial & Federal Government	$699	2014 evaluation on the program and trades for certified installation and weatherization. Results will be used for Home Labeling Study
2012 Furnace Replacement Pilot Program	Residential	FEU	Impact & Process	1	None	$304	Continue from 2013 impact and process evaluations. Evaluations to be conducted yearly to assess participant and contractor feedback
Enerchoice Fireplace Program	Residential	FEU	Impact & Process	4	None	$250	Continue from 2013 impact and process evaluations. Studies to support the P4 Testing
"Give your Furnace/Fireplace Some TLC" - Service Campaign	Residential	FEU	Impact & Process	3	None	$100	Conduct annual participant surveys
ENERGY STAR Water Heater Program	Residential	FEU	Impact & Process	1	None	$161	Process evaluation in 2014/2015. Impact study in 2016
Low Flow Fixtures	Residential	FEU	Impact & Process	2	NGO	$50	Anticipate the annual evaluation studies to partner with pilot evaluations
New Home	Residential	FEU	Impact & Process	1	BC Hydro	$240	2014 process and impact evaluation to assess the labeling for new homes

1 **Table I7-1: FEU Evaluation Plan for 2014-2018 (continued)**

FEU Evaluation Plan for 2014-2018							
Program/Pilot Name	**Program Area**	**Service Region**	**Type of Evaluation or Activities**	**Years the program has been running**	**Proposed Evaluation Partnership**	**Proposed 5 Year Budget (000's)**	**Proposed Timeline**
New Technologies	Residential	FEU	Impact & Process	New	None	$173	Conduct annual process and impact evaluations to follow-up on the market acceptance and technology barriers
Home Energy Reporting	Residential	FEI	Impact & Process	New	None	$90	Conduct annual behavioral survey and impact evaluations
Financing Pilot	Residential	FEI	Impact & Process	1	PowerSense, Banks, C.U.'s	$236	Conduct evaluations in 2015 to validate energy savings assumption and participant feedback
Efficiency Partners Program	Enabling Activities	FEU	Process	2	None	$100	Evaluations to be conducted annually

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Attachment I8

EVALUATION, MEASUREMENT & VERIFICATION FRAMEWORK (DRAFT)

Evaluation, Measurement & Verification Framework (DRAFT)

May 2013

Acknowledgements

The authors wish to acknowledge and express our appreciation to the many individuals who contributed to the development of the FortisBC Evaluation Measurement & Verification Framework.

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1. INTRODUCTION

1.1 *BACKGROUND*

FortisBC Energy Inc. (FEI), FortisBC Energy (Vancouver Island) Inc. (FEVI), and FortisBC Energy (Whistler) Inc. (FEW), are energy utilities providing primarily natural gas throughout most of BC. FortisBC Inc. is an integrated electric utility that generates, transmits and distributes electricity to customers in the southern interior of British Columbia (BC). Collectively these utilities, referred to as "FortisBC" or "the Companies", have developed a framework for evaluation, measurement and verification ("EM&V") activities to examine the effectiveness of its Demand Side Management (DSM) programs. Electric DSM programs are referred to as Power Sense and natural gas DSM programs are referred to as Energy Efficiency and Conservation (EEC).

FEI, FEVI and FEW have been involved with delivering DSM programs and program evaluation since the 1990s[1]. In 2009, following BC Utilities Commission (BCUC) approval of the 2008 EEC Application, the Companies rapidly expanded their menu of natural gas EEC program offerings available to customers, along with the associated budgets. This increase in EEC programming has been followed by an increase in program evaluation activity.

As part of the ramp up in evaluation activity, the Companies recognized the need to develop an evaluation framework and have been examining various evaluation standards and practices that exist within the industry. The BCUC also recognized the need for such a framework and, in its decision with respect to the Companies' 2012-2013 Revenue Requirement Application (Order No. G-44-12), provided the following directive:

> *"The Commission Panel directs the FEU to develop an evaluation plan and to determine an appropriate measurement and verification protocol to be used by the FEU and third party contractors in the EM&V Framework. The Commission Panel further directs the FEU to present the EM&V Framework to the EEC Stakeholder Group and solicit member feedback prior to implementing the Framework."*[2]

FortisBC Inc. has been implementing DSM programs and conducting program evaluation activities since 1989. While the BCUC did not specifically direct the electric utility to submit an EM&V framework, it has provided recommendations through its review of the electric utility's DSM Monitoring and Evaluation (M&E) plans. Most recently, in response to the FortisBC Inc.'s proposed DSM M&E Plan for 2012 through 2014, the BCUC recommended that FortisBC Inc.

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[1] The Companies' earlier EEC activities were referred to in previous regulatory filings with the BCUC as Demand Side Management (DSM) activities.

[2] http://www.fortisbc.com/About/RegulatoryAffairs/GasUtility/NatGasBCUCSubmissions/Documents/G-44-12_FEU-2012-13RR-Decision-WEB.pdf.

broaden its plan by eliminating a minimum savings target threshold to trigger an evaluation and provided some guidance on budget levels for evaluation activity based on industry norms. In their decision document (Order No. G-110-12), the BCUC stated:

> *"FortisBC outlined a possible alternative evaluation plan where every program undergoes evaluation according to the typical timing for the various evaluations described in Section 6.1.2 above. FortisBC estimates the alternative M&E plan would cost an additional $100,000 per year to implement. This would represent just over 6 percent of the Company's total DSM budget…*
>
> *…Given that FortisBC's alternative M&E plan costs $100,000 more per year and that amount remains within the California Evaluation Framework range of common budget allocations to M&E, the Commission Panel recommends that FortisBC resubmit an alternative M&E schedule, such as that submitted in response to BCUC IR 2.98.7, that does not apply a 10 Gwh threshold to trigger evaluation and that follows the typical sequence of evaluations as laid out in the M&E Plan for acceptance by the Commission…*
>
> *…The Commission Panel encourages FortisBC to supplement its own studies with data from other utilities wherever appropriate and to conduct shared evaluations on integrated programs."*[3]

Provincial and Federal regulations also influence a utilities' EM&V activities. In BC, the Demand-Side Measures Regulation, made pursuant to the Utilities Commission Act, sets out many of the definitions, cost effectiveness requirements and calculation considerations, and other demand side activity portfolio requirements for BC utilities, many of which are unique to this jurisdiction. For example, the need to consider societal costs and benefits and the methodology for assigning value to such costs and benefits are set out in the Province's Demand-Side Measures Regulation[4].

[3] BCUC decision on FortisBC Inc.'s 2012-2013 Revenue Requirement and Integrated System Plan Application, http://www.bcuc.com/Documents/Decisions/2012/DOC_31457_G-110-12_FBC-2012-13RRA_Decision-WEB.pdf.

[4] http://www.bclaws.ca/EPLibraries/bclaws_new/document/ID/freeside/10_326_2008.

2. EVALUATION FRAMEWORK

2.1 PURPOSE OF THE EVALUATION FRAMEWORK

The EM&V Framework documents the background, objectives, principles and general practices that will guide the Companies approach, resources and timeframes for EM&V activities. The purpose of the Framework is to provide reliable information relating to when evaluations should be conducted, the types of evaluation that can be conducted, and a discussion of approaches for conducting those studies. It is expected that this document will be updated from time to time in consultation with industry and stakeholders as industry practices evolve and are adopted by the Companies.

The Framework is not a step by step evaluation manual, but it's a guideline that allows for flexibility yet complies with industry standards and practices. The intended audience includes government, policy staff, program managers, program planners and evaluators, and other internal and external stakeholders. Section 2.2 provides a detail explanation of the Companies' evaluation objectives and role of the framework.

2.2 EVALUATION OBJECTIVES

The Companies' have five overriding objectives for conducting evaluations on EEC programs, which include:

1. *Determining whether DSM program objectives are being met.* Program design targets and objectives are determined based on available industry sources. Evaluation activities are conducted to determine if program design targets are being met, such as the amount of energy savings, the number and nature of participants, emission reductions and other targets.
2. *Ensuring that the Companies and ratepayers are obtaining value from their DSM investments.* Evaluation results provide inputs to the cost-benefit analyses in determining the effectiveness of DSM programs. The Companies prescribed cost-benefit analyses are also defined by; the industry standards[5], provincial regulations[6], and the commission's directives.
3. *Providing feedback to program and company management on the performance of DSM programs.* Evaluations help program managers understand how their programs are performing and provide information to help them evolve their programs to be more effective, or perhaps determine if some programs should be discontinued.

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5 The Companies use the cost-effectiveness methodologies articulated in the *California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Programs and Projects.*

6 The Modified Total Resource Cost Test (MTRC) is defined in the *Utilities Commission Act Demand-Side Measures Regulation*

4. *Examining the relationship between a program's activities and a market effect through the use of Market Transformation evaluation.* Evaluations are conducted to assess changes within a market that are caused, at least in part, by the energy efficiency programs attempting to change that market.
5. *Providing assurance to both internal and external stakeholders for the continued support of DSM programs.* Proper evaluation activities ensure that results from DSM programs are credible. This assurance is critical for ongoing support from:
   - External interest groups including customers, BCUC, government, First Nations, communities and other interest groups, trade allies and market participants; and
   - Internal stakeholders including senior management, departments competing for resources, departments responsible for oversight, such as finance and internal audit, and shareholders.

2.3 *EVALUATION PRINCIPLES*

The Companies will conduct their EM&V activities based on the following principles:

- All DSM programs will be evaluated on a program by program basis[7]. The type of evaluations, level of resources dedicated to each evaluation and the extent of the evaluation study will depend upon:
  - Size of investment in the DSM program being evaluated.
  - The amount of risk that a program may not meet cost effectiveness expectations.
  - The amount of data and information available on the effectiveness and evaluation of similar programs by FortisBC and elsewhere in the marketplace,
  - Budget constraints (see Section 4.1 for additional discussion on budgets).

  Subject to the same considerations as above, programs with explicit energy savings targets will have impact evaluations, unless there is a valid reason and an explicit decision is made not to do so.

- Transparency:
  - Reasons for decisions on evaluation methodologies will be documented
  - Assumptions made during the conducting of an evaluation study will be documented.
  - Evaluation activities will be auditable.

[7] DSM programs for which we do not report direct energy savings, such as Educational or Research Programs, may not be subject to the same impact evaluation activities as programs that we do report energy savings for.

  - Summaries of completed evaluations will be presented in the Companies EEC Annual Reports. Final Evaluation Reports will be made available to the BC Utilities Commission and other Stakeholders if requested.

- The use of third party evaluators
  - External consultants may be retained to conduct evaluation activities when internal staffing resources are unavailable or external expertise are needed (See Section 4.3 for additional discussion on staffing resources)
  - Third party evaluators are retained based a combination of the consultant's qualifications, the level of detail evaluation work required and the program size
  - Evaluation staff and Program Managers work collectively to select the suitable external consultant. The selection process and format is determined by the evaluation staff

- The evaluation process will be integral to DSM planning:
  - Evaluation activities will be an important consideration during portfolio and program planning, and as part of the program business case process.
  - Early consideration of evaluation requirements help ensure that the necessary and timely data is collected throughout the program development and implementation process.

- Continuous Improvement:
  - The Companies will continue to monitor the energy efficiency marketplace for industry best practices, standards and protocols for evaluation practices and will adopt those that make practical sense for evaluation activities in BC.
  - The Companies will strive to become industry leaders in evaluation activities.
  - This framework is expected to remain stable over time, but will be updated as necessary

- Timeliness
  - The Companies will strive to conduct and complete evaluations at appropriate times within the resource constraints, and program growth it is subject to for these activities.

2.4 EVALUATION PLANS

This framework is not intended to be or to replace an evaluation plan. Evaluation Plans will be prepared by FortisBC for inclusion with the Companies applications to the BCUC for DSM funding. These plans will detail the programs that the Companies intend to evaluate, the types of evaluations the Companies intend to undertake, and general time frames for the evaluation activities during the period of the funding request. Progress made toward completing the evaluation plan, and any needed adjustments to the plan, will be provided in the Companies' Annual DSM reports.

3. TYPES OF EVALUATION STUDIES

There are a range of EM&V studies that are undertaken to evaluate FortisBC DSM programs. The type, timing and frequency of studies, and the evaluation practices implemented for each study will depend on a variety of factors including the type of program being evaluated, the level of program spending, experience with similar programs, the number of program participants, the quality of data upon which any energy savings assumptions are based, and more. For clarity, the evaluation component of EM&V refers to the broad spectrum of evaluation activities that can make up an evaluation plan while Measurement and Verification refers more specifically to the range of methodologies used to measure and verify actual energy savings from implementing a program of demand side measures. Hence measurement and verification is a subset of evaluation activities.

3.1 *PROCESS EVALUATIONS*

Process evaluations examine the effectiveness of program delivery. Objectives for process evaluations include improving program implementation and program delivery as well as ensuring high satisfaction levels among customers, trade allies and other program participants. Areas reviewed include incentive and rebate levels; communication and promotional initiatives; program operations and implementation; customer awareness and acceptance as a customer service (satisfaction) of energy efficient technologies and measures; and trade ally (distribution & implementation) awareness and acceptance. Process evaluations are generally first conducted within 6 to 18 months following the launch of a new program and for long duration programs on a periodic basis thereafter.

3.2 *MARKET EVALUATIONS*

Market evaluations test a DSM program's effectiveness at increasing the market penetration of an efficient technology or measure. Objectives for market evaluations include measuring increases in market penetration of energy efficient technologies and assessing the share of measures attributable to the program. Market effects often have a larger impact on the adoption rate of a product or technology than they receive credit for, and taking credit for this can often negate some of the free rider impacts. Evaluation activities include:

- assessing market potential and market penetration over time through a review of the availability, accessibility and affordability of energy efficient technologies and measures,
- identifying barriers and assessing the program's effectiveness at overcoming barriers, and
- assessing how much of the remaining market the program can be expected to address.

When a market evaluation is determined to be necessary, the timing must allow a sufficient period for program implementation and uptake. These evaluations are therefore generally conducted between two and three years following a program launch.

3.3 *IMPACT EVALUATIONS*

Impact evaluations measure energy savings achieved by a DSM program. Objectives for impact studies include:

- measuring decreases in natural gas consumption,
- estimating free-rider and spill-over (market) effects to determine net savings impacts, and
- determining the cost effectiveness of the program according to a set of cost-benefit analysis based on industry and/or regulatory standards.

Impact evaluations will draw on information available from measurement and verification studies, energy consumption data (billing analysis), results of similar programs and evaluations in other jurisdictions, and/or benchmarking studies as appropriate and where such information exists. As with process evaluations, an impact evaluation may include comments on appropriateness of program design and/or suggestions for changes to increase effectiveness.

The timing of impact evaluations must allow a sufficient period of program operation for implementation and uptake, including the adoption of process improvements that might be identified during the early program period. Generally, impact evaluations are conducted between two and three years following a program's launch. However, depending on the program life cycle, impact evaluations may be conducted annually to provide a preliminary check on the engineering estimates or when findings are required to launch the program for a second year.

For some programs, impact evaluations may occur in two stages. The first stage will involve participant survey work to improve the Companies' knowledge about the implementation of individual measures, and a second stage that involves a billing or other more detailed analysis.

3.4 *PILOT STUDIES*

Pilot studies are an important component of the Companies' DSM portfolio and are conducted to provide necessary research into potential new efficiency measures or technologies in support of developing new programs or initiatives. Research objectives can include understanding how the market may respond to the introduction of a new measure, obtaining adequate performance data for a new measure (valid for local conditions), or both. FortisBC limits pilot study activity to the assessment of new efficiency measures or technologies that are market ready, but not yet widely available or adopted within BC.

Studies focused on obtaining an understanding of the market include typical market research investigations such as participant surveys. Studies focused on obtaining measure performance data include measurement and verification studies. In both cases, the pilot is used to test the idea on a small scale and hence reduce risk and cost if the program concept requires modifying prior to the launch of a full scale program or if performance results are insufficient for the development of a full program.

3.5 *MEASUREMENT AND VERIFICATION ACTIVITIES*

M&V refers to a range of activities or studies used to determine the performance of an installed DSM measure. M&V activities are most often conducted as part of Pilot Study evaluations and as part of evaluating custom commercial and industrial programs where adequate data on measure/technology performance does not exist. M&V activities may also be implemented as part of the evaluation of full scale programs if it is felt that additional measure performance data is required.

Wherever practical, the Companies intend to follow the International Performance Measurement and Verification Protocol (IPMVP)[8] in conducting M&V activities for evaluating DSM programs and pilots. FortisBC's review of industry standards, guidelines and protocols indicates that IPMVP is growing in use as a standard resource for guiding the design of M&V activities and provides both a comprehensive and flexible approach. It should be noted that while IPMVP summarizes common industry practices for M&V activities and sets out a range of methodologies that can be followed under ideal study conditions and in absence of budget or timing constraints, it also acknowledges that ideal study conditions and large M&V budgets are seldom available. As such, the Protocol provides guidelines for the evaluator to follow under less than ideal conditions and in the face of budget and timing constraints. The Protocol therefore allows room for judgment by the evaluator under less than ideal evaluation circumstances.

The following M&V principles[9] are embedded in the IPMVP:

Accurate M&V reports should be as accurate as the M&V budget will allow. M&V costs should normally be small relative to the monetary value of the savings being evaluated. M&V expenditures should also be consistent with the financial implications of over- or under-reporting of a project's performance. Accuracy tradeoffs should be accompanied by increased conservativeness in any estimates and judgments.

[8] International Performance Measurement and Verification Protocol. Concepts and Options for Determining Energy and Water Savings. Prepared by the Efficiency Valuation Organization. www.evo-world.org. January 2012.
[9] These principles have been reproduced from Chapter 3 of the IPMVP (see also the preceding footnote).

Complete The reporting of energy savings should consider all effects of a project. M&V activities should use measurements to quantify the significant effects, while estimating all others.

Conservative Where judgments are made about uncertain quantities, M&V procedures should be designed to under-estimate savings.

Consistent The reporting of a project's energy effectiveness should be consistent between:

- different types of energy efficiency projects;
- different energy management professionals for any one project;
- different periods of time for the same project; and
- energy efficiency projects and new energy supply projects.

'Consistent' does not mean 'identical,' since it is recognized that any empirically derived report involves judgments which may not be made identically by all reporters. By identifying key areas of judgment, IPMVP helps to avoid inconsistencies arising from lack of consideration of important dimensions.

Relevant The determination of savings should measure the performance parameters of concern, or least well known, while other less critical or predictable parameters may be estimated.

Transparent All M&V activities should be clearly and fully disclosed.

3.6 EVALUATION METHODOLOGIES

A range of evaluation methodology types can be utilized to determine the energy savings achieved from the implementation of an efficiency measure. One way to think of this range of methodologies is as of a tool box, with each methodology being a different tool that the evaluator can bring out of the tool box to apply to the evaluation problem. The best tool (or methodology) to use depends on the circumstances of the required evaluation and the available resources. In many cases, more than one methodology will be applied to evaluate the energy savings achieved from an efficiency measure or program of measures. Common evaluation methodologies are summarized as follows:

Billing Analysis

Billing analysis uses customer billing information to assess the effect of a DSM program on customer energy consumption. The analysis typically requires a baseline billing history period in the absence of the EEC measure being installed and one year of billing data following the measure installation. The fundamental assumption is that the only, or major, change in energy consumption over this period has resulted from the EEC measure being evaluated. This approach requires both data cleaning to ensure the quality of the billing data (i.e.: no missed billing reads or estimated bills) and weather adjusting. Market research with the customers involved to is also required to determine if there were changes in occupancy or usage in the premises. When possible, a billing analysis should include both participants and non-participants so that outside influences, such as price changes for fuels, can also be accounted in the analysis. Billing analysis is generally more effective for programs with higher customer savings. Lower savings levels (1-3% for example) can be more difficult to explain using billing analysis due to the potential for other factors to influence energy use patterns.

Metering

Metering involves the installation of energy use meters around the measure being studied to determine specific energy inputs and outputs both prior to and subsequent to the installation of an energy efficiency measure. In the residential sector, metering is primarily used in pilot projects to improve the accuracy of determining the energy impact associated with a DSM measure. Metering can also be used as part of monitoring studies to determine energy usage of appliances over time.

In the commercial and industrial sector metering is commonly used to determine the impact of both custom and pilot programs, where there is insufficient information about the impact of specific measures. Metering analysis can be done on a short-term “spot” basis or on a longer term basis. Long term metering of end-use before and after the installation is preferable to spot metering where economic, and where the participant behavior is not expected to be affected by the measurement.

Simulation Modeling

The effects of efficiency improvements in both residential and commercial buildings can be estimated through simulation of energy use under various scenarios using computer based energy models. In the residential sector, HOT2000 is a commonly used model developed for this purpose, while commercial energy use modeling often requires more complex models such as DOE2. Simulation modeling may be used as part of program design, to obtain initial estimates of energy impact, and/or as part of an initial impact evaluation where billing or metering data is not yet available to refine the modeling estimates.

Engineering Estimates

This method is based on an engineering analysis of the difference in efficiency between the “standard” measure and the installed efficiency measure. It may be based on standard efficiency measurements, such as the difference in EF rating for hot water tanks or the difference in AFUE ratings for furnaces. At a more basic level, it may require analysis of the differences in design of the energy efficient equipment being installed.

Statistically Adjusted Engineering Estimates

This approach utilizes engineering models and statistical approaches to examine the amount and nature of customer end-use loads. The results of simulated end-use loads from engineering methods become inputs into statistical models and are adjusted on the basis of customers' observed loads (statistical data). The resulting end-use loads, called statistically adjusted engineering (SAE) loads, depend on a variety of conditioning variables such as weather and the size and type of the customer's dwelling, or perhaps income and other household characteristics identified as part of the statistical analysis.

Surveys

Survey data is often the basis of both process and impact evaluations. Surveys may take the form of mail, telephone, internet panels, and more recently social media analysis, and may be done with participants and non-participants in any given program. Data collected includes awareness of the program, satisfaction, persistence, usage of the efficiency measure and information to help establish levels of free riders and spillover.

Field Studies and Laboratory Research

This type of analysis can be undertaken are as part of pilot program projects when the utility is conducting a detailed review of a small number of a specific efficiency measures that are “market ready” but not in wide use in the utility’s service territory. Typically, the research combines survey data from the customer where the pilot project is being conducted (to understand parameters such as usability and satisfaction with the technology), and metering of baseline and post implementation periods to determine the change in energy use.

Site Visits

Site visits can be used to examine programs across all customer classes to confirm that the target efficiency measure has been successfully installed and is in operation. Site visits can be combined with interviews of homeowners or facility operators to provide additional data valuable to the evaluation process.

Statistical Analysis

Mathematical approaches such as regression analysis and conditional demand analysis are often used in evaluation studies. These approaches can approximate some of the benefits of metering, but through the use of surveys or audits combined with billing histories can include a much larger group of customers at a much lower evaluation cost. Offsetting the cost advantages of this approach, however, are increased uncertainties due to potential changes in energy use unrelated to the efficiency measure being studied.

3.7 OTHER EVALUATION CONSIDERATIONS

Evaluation activities need to consider a number of issues not yet discussed.

Multi – Fuel Impacts

DSM programs may impact the use of electricity, natural gas and other fuels. Often, a program aimed primarily at reducing natural gas consumption may also impact electricity consumption or vice versa. For example a furnace efficiency program that encourages the installation of a variable speed fan might reduce both natural gas and electricity consumption. Natural gas and electricity are the most commonly used energy fuels in BC's built environment; however, the potential exists for the consumption of other fuels, such as propane or heating oil, to similarly be impacted by a DSM program. The potential for such multi-fuel impacts needs to be addressed as part of program evaluation activities.

Persistence of Savings

For natural gas programs, the persistence of energy savings over time is often a function of the life span of the measure or technology. In some cases, however, persistence can be more complex. There may be a need to determine if the equipment or technology being installed will maintain its efficiency rating over time. Also, circumstances may require a shorter (than life span) duration of savings to be assessed such as may occur if the program accelerates the installation of a high efficiency measure that would otherwise require installment at a later date. These complexities must also be addressed as part of the evaluation activities.

Interactive Effects

Impact evaluations should look more broadly than just the energy savings that result from the change in efficiency of the energy conservation measure. Changes in the measure can cause a number of other changes. For example, the evaluation of the residential furnace program (from 2005 to 2007) illustrated that upgrading a furnace has larger impacts than just replacing one technology with another. This evaluation illustrated that the new furnace changed the usage of secondary heat for a share of participants, and also that increases in comfort may result in homeowners selecting lower temperatures in their dwellings. The changes can affect the overall efficiency of energy use, and can also result in changing the balance of all fuel types in use in the building usage including natural gas, electricity and wood.

Attribution of Savings from Joint Programs

FortisBC also undertakes and participates in integrated electricity and natural gas programs, both within the FortisBC utilities and between the FortisBC natural gas utilities and BC Hydro. Attributing for the energy savings and carbon emission reductions that result from such projects among partner organizations needs to be fair, consistent and transparent. FortisBC will work with its partners to develop attribution rules for sharing the credit of energy savings appropriately among program partners and prevent double counting.

Related Studies

In addition to evaluation programs, FEI undertakes a number of studies which are used to support both program development and evaluation. These include:

- Sector End Use Studies conducted periodically to provide a "snapshot" of customers' products and equipment. These studies often include supporting analysis such as "Conditional Demand Analysis" (CDA) components that provide estimates of the amount of natural gas usage by end uses.
- Conservation potential reviews, which are systematic assessments of the current status of energy efficiency in the installed appliance stock in the marketplace and projections of the main end uses where efficiency improvements are possible, along with estimates of potential energy reductions.

3.8 FEEDING EM&V STUDY RESULTS INTO EEC PLANNING

Evaluation and program management staff at FortisBC review the results of evaluation studies and reports to determine if changes to programs are needed. In the case of M&V activities, this review will assist staff in determining if new programs should be developed based on pilot study results or if adjustments need to be made to the data used to determine program or project cost effectiveness. For program design and development, project managers need to consider additional factors such as human, technical and budgetary resources, portfolio priorities and any feedback received from stakeholders. If recommended changes to programs necessitate approval from the BCUC, FortisBC will seek input on those changes from the appropriate Stakeholder Advisory Group.

4. EVALUATION RESOURCES

Effective management of evaluation activities requires both financial and staffing resources.

4.1 EVALUATION BUDGETS

Industry practice for budget spending on EM&V activities appears to range between 2 and 10 percent, and average approximately 4 percent of spending on overall energy efficiency and conservation program budgets[10]. This level of spending is in keeping with the principle that evaluation budgets should be a small component of overall programming budgets. That is, an evaluation budget, and therefore evaluation efforts, should not be so extensive that they unnecessarily cause a program to fail a cost-benefit test and thereby prevent the program from being implemented. As such, the Companies will plan EM&V budgets not to exceed 10 percent of overall DSM spending, and will target an annual EM&V budget limit of 3 to 6 percent of the overall EEC portfolio spending.

On a program by program basis, there may be occasions when either higher or lower budgets for individual programs may be appropriate. A new program for which there is very little industry data available and for which energy efficiency performance may have a higher degree of uncertainty, may warrant a higher spending level. Pilot studies that examine the actual performance of a newer technology or measure, for example. In other cases, a program being implemented may benefit from similar programs in other jurisdictions having similar geographic and climate settings may be abundant, evaluation data may be well established and smaller budgets are appropriate.

4.2 EVALUATION ORGANIZATION

Wherever possible, the evaluation of programs that span across the Companies' separate utility service territories will be conducted as a single evaluation in order to take advantage of evaluation cost efficiencies and incorporate consistency across service areas. Similarly, evaluations of joint electric and gas DSM programs will be conducted as a single for the partners involved in delivering the program.

Evaluations will be conducted or managed by staff who are independent from the program managers and other staff responsible for designing and implementing DSM programs. Staff responsible for evaluation activities will have separate reporting lines from that of program development and implementation staff wherever practical within the utilities.

4.3 STAFFING RESOURCES

The companies recognize that a combination of internal staffing resources and external professional consulting services will be needed to undertake the full range of evaluation

[10] California Evaluation Framework. June 2004. TecMarket Works. p75.

activities that are required for the level of DSM program activity being implemented. The level of internal staff resourcing for evaluation activities will be sufficient to ensure that a base level of evaluation activity can be managed as appropriate for the level of program activity being delivered by the Companies.

External consultants will be retained whenever increased levels of evaluation activity above the base level are such that they cannot be completed by internal staff, and wherever in-house expertise is not available to conduct the necessary studies. Staffing and consultant resources will also be managed within the appropriate budgeting parameters (see Section 4.1).

Sufficient internal staff resources are needed to plan evaluation activities, manage evaluation projects, review third party consultation studies / reports and conduct some evaluation analysis.

- Development of RFPs
- Working with purchasing to obtain quotes from qualified service providers
- Developing selection criteria for the proposals
- Managing the selection criteria
- Managing the evaluation projects
- Maintaining communications with interested parts of the organization (esp. EEC)

Evaluation staff will be involved in the program planning process to determine the major evaluation issues for each program and ensuring that sufficient evaluation resources are available.

Staff Resources for Measurement and Verification Activities:

Internal engineering expertise is required to develop technical measurement and verification process requirements, develop measurement and verification plans, inspect measurement and verification work being done by third parties, be able to conduct measurement and verification activities when necessary. Number of internal staff must be sufficient to manage base level work load, provide consistent project management, and must be managed relative to overall EEC budgeting requirements.

4.4 *ROLE OF STAKEHOLDER ADVISORY GROUPS*

Advisory Groups made up of key stakeholders external to the Companies have been established by FortisBC to provide insight and feedback on the Companies' portfolios of DSM activities. Advisory Group members are not expected to have a high level of expertise in EM&V and are not expected to provide input on individual evaluation or measurement and verification projects. The Advisory Groups will have access to evaluation report summaries and members may request to see any of the full EM&V reports that are prepared once they are final. Members will also be able to contact FortisBC staff for more detailed discussions/explanations if desired. A list of evaluation activities will also be included in the Companies' Annual Reports for their DSM programs. From time to time, the Companies may review EM&V issues and results with the Advisory Groups for discussion and feedback.

The companies submit evaluation plans through either their Revenue Requirements Application or other filings for approval by the BCUC. Any stakeholder can participate in the review of the evaluation plans through the BCUC's regulatory review process[11].

[11] Visit www.bcuc.com

Appendix J

DRAFT FORM OF ORDER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

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VANCOUVER, BC V6Z 2N3 CANADA
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TELEPHONE: (604) 660-4700
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DRAFT ORDER

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Energy Inc.
For Approval of a Multi-Year Performance Based Ratemaking Plan for the years 2014 through 2018

BEFORE:

(Date)

WHEREAS:

A. On June 10, 2013, FortisBC Energy Inc. (FEI) applied to the British Columbia Utilities Commission for approval of a proposed multi-year performance based ratemaking plan (PBR Plan) for the years 2014 through 2018, and for approval of permanent natural gas delivery rates effective January 1, 2014, pursuant to sections 59 to 61 and 89 of the Utilities Commission Act (the Act);

B. FEI seeks, among other things, approval, pursuant to sections 59 to 61 of the Act, of a permanent natural gas delivery rate decrease of 1.8 percent as compared to 2013 interim delivery rates, effective January 1, 2014;

C. FEI further seeks approval of the Rate Stabilization Adjustment Mechanism (RSAM) rider for applicable rate classes for 2014 as set out in the Application;

D. FEI seeks, among other things, approvals including: allocation of costs for corporate and shared services; discontinuation, continuation, and creation of deferral accounts and the amortization and disposition of balances in deferral accounts;

E. FEI, FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc. (together, the "FEU") seek acceptance pursuant to section 44.2 of the Act for Energy Efficiency and Conservation (EEC) expenditures; and

F. The Commission has reviewed the Application and concludes that the requested changes as outlined in 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 for FEI:

    a. Approval of the PBR mechanisms set out in Section B of this Application for setting delivery rates for the years 2014-2018.

    b. Approval of permanent delivery rates for all non-bypass customers effective January 1, 2014, representing a decrease of 1.7 percent as compared to 2013 interim delivery rates. The decrease is to be applied to the delivery charge and the basic charge will remain at 2013 levels.

    c. Approval of the RSAM rider for customers served under FEI Rate Schedules 1, 1B, 1S, 1X, 2, 2U, 2X, 3, 3U, 3X and 23 effective January 1, 2014 of ($0.118)/GJ as set out in Section E Schedule 63 of the Application.

    d. Approval of the continuation of the debiting of the MCRA and crediting of the delivery margin revenue in the amount of $3.6 million per year for 2014 through 2018 as set out in Section C2.3 of the Application.

    e. Approval of the allocation of costs for corporate services between FortisBC Holdings Inc. and FEI, as reflected in the Corporate Services Agreements between FortisBC Energy Holdings Inc. and FEI, as described in section D3.6 of the Application.

    f. Approval of the allocation of costs for shared services between FEI and FEVI, as described in section D3.6 of the Application, subject to FEVI receiving regulatory approval for the allocation in its next RRA filing.

    g. Approval of the allocation of costs for shared services between FEI and FEW, as described in section D3.6 of the Application, subject to FEW receiving regulatory approval for the allocation in its next RRA filing.

    h. Approval of the discontinuance, modification, and creation of deferral accounts, and the amortization and disposition of balances of deferral accounts, all as set out in section D4, Appendices F-4 and F-5 to the Application and summarized in the following table.

Type Of Change	Account	Company	Reference
New Account	2014 - 2018 PBR Application Costs	FEI	Section D4.1.1; amortization period of 5 years commencing January 1, 2014
	TESDA Overhead Allocation Variance	FEI	Section D4.1.2; disposition of account will be addressed in 2014 Annual Review
Amortization Period Change - New or Modified	Midstream Cost Reconciliation Account	FEI	Section D4.2.1; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Revenue Stabilization Adjustment Mechanism	FEI	Section D4.2.2; change from 3 year amortization period to 2 year amortization period, commencing January 1, 2014
	Pension and OPEB Variance	FEI	Section D4.2.4; change from 3 year amortization period to a 12 year amortization period (EARSL), commencing January 1, 2014
	Customer Service Variance Account	FEI	Section D4.2.5; 5 year amortization period, commencing January 1, 2014
Other	Energy Efficiency and Conservation	FEU	Section D4.2.6 The continuation of the FEI EEC Incentive non-rate base deferral account attracting AFUDC, approved by Commission Order G-44-12, to capture the actual as spent costs above the amount forecast in rates, up to the approved funding envelope, for 2014 through 2018, and to transfer the FEI portion of the balance to the FEI EEC rate base deferral account in the following year and recover the amount transferred over a ten year period beginning the year in which the balance is transferred. Additionally, FEI is seeking to transfer the FEI portion of the balance in this deferral as at December 31, 2013 to the FEI rate base EEC deferral account and to amortize the amounts in rates over 10 years beginning in 2014
	Biomethane Program Costs	FEI	Section D4.2.7; inclusion of application costs related to the FEI Biomethane Post Implementation Report
	NGV for Transportation Application	FEI	Section D4.2.8; inclusion of Rate Schedule 16 application costs[1]

[1] Pursuant to Commission Order G-88-13 received on June 4, 2013, Rate Schedule 16 Application Costs will be addressed through an Evidentiary Update to this Application once the Rate Schedule 16 Decision has been fully evaluated.

Type Of Change	Account	Company	Reference
	Generic Cost of Capital Application Costs	FEI	Section D4.2.9; amortization period of 2 years commencing January 1, 2014
	Amalgamation and Rate Design Application Costs	FEI	Section D4.2.10; transfer FEI's portion of the balance to rate base January 1, 2014, amortization of 3 years commencing January 1, 2014
	Residual Delivery Rate Riders	FEI	Section D4.2.11; inclusion of new residual balances for Rate Riders 3, 4 and 8
	On-Bill Financing Pilot Program	FEI	Section D4.3.1; transfer the balance of this account as at December 31, 2014 to rate base on January 1, 2015 and continue to recover the balance from OBF pilot program customers over approximately a ten year period until the account is fully recovered.
Discontinuance	Southern Crossing Pipeline Tax Reassessment	FEI	Section D4.4.2; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2015
	Tilbury Property Purchase (Subdividable Land)	FEI	Section D4.4.3; amortization period of 1 year commencing January 1, 2014 and then discontinuance of this account effective January 1, 2016
	CNG and LNG Recoveries	FEI	Section D4.4.4; discontinuation of this account effective January 1, 2015
	BFI Costs and Recoveries	FEI	Section D4.4.5; discontinuation of this account effective January 1, 2014
	Overhead and Marketing Recoveries from NGT Class of Service	FEI	Section D4.4.6; 1 year amortization period, commencing January 1, 2014; discontinuation of this account effective January 1, 2016
	2011 CNG and LNG Service Costs and Recoveries	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Olympic Security Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	IFRS Implementation Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2009 ROE and Cost of Capital Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	2010-2011 Revenue Requirement Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015

Type Of Change	Account	Company	Reference
	2012-2013 Revenue Requirement Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	CCE CPCN Application	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Deferred Removal Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	US GAAP Conversion Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	US GAAP Transitional Costs	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2015
	Mark to Market - Customer Care Enhancement Project	FEI	Section D4.4.7; discontinuation of this account effective January 1, 2014

i. Approval of changes to the following accounting policies to be used in the determination of rates for FEI, effective January 1, 2014:

   i. Modification to the approved Lead Lag days with the removal of the HST lead days and the insertion of GST and PST lead days as set out in Section D3.2 of the Application.

   ii. Inclusion of the retiree portion of pension and OPEB expenses in benefit loadings for O&M and capital as set out in Section D3.1 of the Application.

   iii. Capitalization of the annual software costs paid to vendors in support of upgrade capability as set out in Section D3.1 of the Application.

   iv. Depreciation of assets to commence January 1 of the year following when they are placed into service as set out in Section D3.3 of the Application.

   v. A depreciation rate of 12.5 percent for asset class 484 Vehicles as set out in Section D3.1 of the Application.

   vi. Approval to discontinue the reconciliation of US GAAP to Canadian GAAP in future BCUC Annual Reports as set out in Section D3.1 of the Application.

2. With respect to Energy Efficiency and Conservation (EEC) expenditures, the Commission orders as follows:

   a. Pursuant to section 44.2(a) of the Act, the Commission accepts the following EEC expenditure schedules for the FEU to be spent on the EEC program areas described in Appendix I of the

Application: Up to $34.353 million for 2014, $37.30 million for 2015, $37.358 million for 2016, $37.664 million for 2017, and $38.982 million for 2018.

b. The Commission approves the continuation of the EEC framework as previously approved by the Commission, with the following changes:

   i. Approval of the administration by a neutral third party of EEC funds provided to projects with a third party thermal energy component.

   ii. Approval of the incorporation of spillover effects and the attribution of the benefit of savings from the introduction of codes and standards on a program-by-program basis, for the purpose of reporting on cost effectiveness in the EEC Annual Report pursuant to section 43 of the Act.

   iii. Approval for the FEU to transfer funds within a program area to a new program without prior Commission approval, provided that the new program is in accordance with the DSM Regulation, EEC principles, existing benefit/cost test requirements, and has not been previously rejected by the Commission.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 2013.

BY ORDER