FORTISBC INC.

Application for Approval of a Multi-Year Performance Based Ratemaking Plan for 2014 through 2018

Volume 2 - Appendices

July 5, 2013

Appendix A

GLOSSARY OF TERMS

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2012-2013 RRA Decision – August 15, 2012 Decision in the Matter of FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan and Order G-110-12

AACE – Association for the Advancement of Cost Engineering

AAM – Automatic Adjustment Mechanism

AcSB – Accounting Standards Board

Act – Utilities Commission Act, see also *UCA*

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

AGA - American Gas Association

AIFR – All Injury Frequency Rate, total number of work-related Lost-Time Injuries or Illnesses plus Medical Aid Injuries in a year.

ALC – Agriculture Land Commission

ALR – Agricultural Land Reserve

AM/FM – Automated Mapping/Facilities Management

AMI – Advanced Metering Infrastructure

AMR – Automated Meter Reading

Application – FortisBC Inc. Application for Approval of a Multi-year Performance Based Ratemaking Plan for 2014 through 2018

AUC – Alberta Utilities Commission

ASL – Average Service Life

AVL – Automated Vehicle Locator

B/C Ratio – Benefit Cost Ratio

BC or B.C. – British Columbia

BC-AWE – British Columbia Average Weekly Earnings

B&V – Black and Veatch

BC Hydro – British Columbia Hydro and Power Authority

BC Hydro PPA – BC Hydro Power Purchase Agreement, BC Hydro supplies electricity to FBC pursuant to the BC Hydro PPA dated October 1, 1993. The 1993 PPA expires on September 30, 2013 and will be replaced by a new PPA dated May 21, 2013 once approved by the Commission.

BCC – Backup Control Centre

BCDSR – BC Dam Safety Regulation

BC MRS – British Columbia Mandatory Reliability Standards, see also "Mandatory Reliability Standards"

BCSA – British Columbia Safety Authority

BCTC – British Columbia Transmission Corporation, now BC Hydro

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

BIP – Building Improvement Program

BPPA – Brilliant Power Purchase Agreement

BSSC – Business Systems Steering Committee

BTS – Brilliant Terminal Station

Capex – Capital expenditures

CBOC – Conference Board of Canada

CCA – Capital Cost Allowance

CDD – Cooling Degree Days, which is a measurement designed to reflect the demand for energy needed to cool a home or business, and derived from measurements of outside air temperature

CDOR – Canadian Dealer Overnight Rate

CDPR – Conservation Demand Potential Review

CEA – Canadian Electricity Association

CEATI – Centre for Energy Advancement through Technological Innovation

Celgar – Zellstoff Celgar Limited Partnership

CEO – Conservation Education and Outreach

CEP – Capital Expenditure Plan

CEUS – Commercial End Use Survey

CGAAP – Canadian Generally Accepted Accounting Principles

CIAC – Contributions in Aid of Construction

CIP – Customer Information Portal, or in the context of Information Systems, Cyber Infrastructure Protection

CMMS – Computerized Maintenance Management System (CMMS)

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

Cominco – now Teck Metals Ltd.

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

Company – FortisBC Inc. or FBC

COPE – Canadian Office of Professional Employees

COR – Cost of Removal, or in the context of safety management, Certificate of Recognition

CPA – Canal Plant Agreement

CPC/CBT – Columbia Power Corporation/Columbia Basin Trust

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

CSI – Customer Satisfaction Index

CWIP – Construction Work in Progress

DC – Direct Current

DFO – Department of Fisheries and Oceans Canada

DSM – Demand-Side Management, defined as "any utility activity that modifies or influences the way in which customers utilize energy services".

EARSL – Expected Average Remaining Service Life

ECAP – Energy Conservation Assistance Program

EEC – Energy Efficiency and Conservation

EECAG – Energy Efficiency and Conservation Advisory Group

EH&S – Environment, Health & Safety

EIT – Engineer in Training

EM&V – Evaluation, Measurement and Verification

EML – Effective Measure Lifetime

EMS – Environmental Management System

Energy Plan - 2007 BC Energy Plan

EPP – Equal Payment Plan

ESK – Energy Saving Kit

ESM – Earnings Sharing Mechanism

FAI – FortisAlberta Inc.

FASB – Financial Accounting Standards Board

FBC – FortisBC Inc. (electric)

FIS – Forecasting Information System

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

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

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

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

FPHI – FortisBC Pacific Holdings Inc.

FTE – Full Time Equivalent

GAAP – Generally Accepted Accounting Principles

GCOC – Generic Cost of Capital proceeding

GDP – Gross Domestic Product

GIS – Geographic Information System

GST – Goods and Services Tax

GWA – General Wheeling Agreement

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

HIP – Home Improvement Program

HLH – Heavy Load Hours, include all hours between 06:00 (Hour Ending 7) and 22:00 (Hour Ending 22) Monday to Saturday, excluding NERC holidays.

HR – Human Resources

HST – Harmonized Sales Tax

HVAC – Heating, Ventilation, and Air Conditioning

IAM – Institute of Asset Management

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

IPP – Independent Power Producer

IRs – Information Requests; or in the context of inflation factors, means Incentive Regulation.

IS – Information Systems

ISP – FBC's 2012 Integrated System Plan

I-Factor – Inflation Factor

ICM – Incremental Capital Module

ISO – International Standards Organization

IT – Information Technology

IVR – Interactive Voice Response

LAN – Local Area Network

LDC – Local Distribution Company

LFC – Load Forecast Committee

LiveSmart BC – LiveSmart BC Efficiency Incentive Program

LLH – Light Load Hours, include all Sundays and NERC holidays, and hours between 22:00 (Hour Ending 23) and 06:00 (Hour Ending 6) each night.

LRMC – Long Run Marginal Cost

LTRP – Long Term Resource Plan

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

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

MEMNG – Ministry of Energy, Mines and Natural Gas

Mid-C – Middle Columbia trading hub, located in central Washington along the Columbia River.

MOCB – Minimum Oil Circuit Breaker

MRS – Mandatory Reliability Standards

MTN – Medium Term Note

MTRC – Modified Total Resource Cost Test

MW – Megawatt

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

NERC – North American Electric Reliability Corporation

NOAV – Notice of Alleged Violation

NRB – Non-Regulated Business

NSA – Negotiated Settlement Agreement

NSF – Non-sufficient Funds

NSP – Negotiated Settlement Process

NTG – Net-to-Gross Ratio

NWPP – Northwest Power Pool

O&M – Operating and Maintenance Costs

OATT – Open Access Transmission Tariff

OBF – On-Bill Financing

OEB – Ontario Energy Board

OEM – Original Equipment Manufacturer

OPEB – Other Post Employment Benefits

Opex – O&M expenditures

OSC – Ontario Securities Commission

P&E – Planning and Evaluation

PACA – Participant Assistance/Cost Award

PBR – Performance Based Ratemaking

PC – Personal Computer

PCB – Polychlorinated Biphenyls

PCT –Participant Cost Test

PIC – Person in Charge

PIF – Productivity Improvement Factor

PLP – Princeton Light and Power

PLT – Power Line Technician

PP&E – Property, Plant and Equipment

PPA – Power Purchase Agreement

PPE – Power Purchase Expense

PPM – Project Portfolio Management’

PRM – Planning Reserve Margin

PSH – Pumped Storage Hydro

PST – Provincial Sales Tax in British Columbia

PSU – Performance Share Units

PV – Present Value

Rate Base – Utility Mid Year Rate Base

RCR – Residential Conservation Rate, FBC's default rate for residential service, refer also to *RIB*

REUS – Residential End Use Survey

RIB – Residential Inclining Block, refer also to RCR

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

ROE – Return on Equity

ROW – Right of Way

RRA – Revenue Requirements Application

RS 3808 – (BC Hydro) Rate Schedule 3808, BC Hydro supplies electricity to FBC pursuant to the BC Hydro PPA and at embedded rates set out in BC Hydro's Rate Schedule 3808.

RSDA – Rate Stabilization Deferral Account

RSDM – Rate Stabilization Deferral Mechanism

SAIDI – System Average Interruption Duration Index, is the amount of time the average customer's power is off per year (i.e. the total amount of time the average customer's clock would lose during a year)

SAIFI – System Average Interruption Frequency Index, is the average number of interruptions per customer served per year (i.e. the number of times the average customer would have to reset their clock during the year).

SAP – FBC's main integrated IT system

SARA – Species at Risk Act

SCADA – System Control and Data Acquisition

SCC – System Control Centre

SEC – United States Securities and Exchange Commission

SONET – Synchronous Optical Networking

SQI – Service Quality Indicator

T&D – Transmission and Distribution

Teck – Teck Metals Ltd.

TFP – Total Factor Productivity.

Totex – Total Expenditure

TPP – Transfer Pricing Policy. See also COC/TPP

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

UCA – Utilities Commission Act, see also *Act*

UCT or 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

ULE – Upgrade and Life Extension

UPC – Use per Customer

USoA – BCUC Uniform System of Accounts

WACC – Weighted Average Cost of Capital

WACD – Weighted Average Cost of Debt

WAN – Wide Area Network

WAX – Waneta Expansion Plant

WAX CAPA – Waneta Expansion Capacity Purchase Agreement

WECC – Western Electricity Coordinating Council, the Regional Entity responsible for coordinating and promoting Bulk Electric System reliability in the Western Interconnection.

West Kootenay Power – West Kootenay Power and Light Company

X-Factor – Productivity Improvement Factor

Appendix B1

CORPORATE HISTORY

FORTISBC INC.

OVERVIEW

FortisBC Inc. (FBC) is a company originally incorporated as West Kootenay Power and Light Company, Limited pursuant to the *West Kootenay Power and Light Company, Limited, Act 1897* (British Columbia), as amended. The Act permitted the West Kootenay Power and Light Company (West Kootenay Power) the right to operate within fifty miles of Rossland. West Kootenay Power's service area was extended to within 150 miles of Rossland in 1929.

West Kootenay Power and Light Company Limited was formed in 1897 by business people involved in Rossland's booming mining industry. West Kootenay Power was created to supply power to one of Rossland's leading mines, the Centre Star. On July 15, 1898, the company completed construction of its first dam on the Kootenay River at Bonnington Falls (Lower Bonnington).

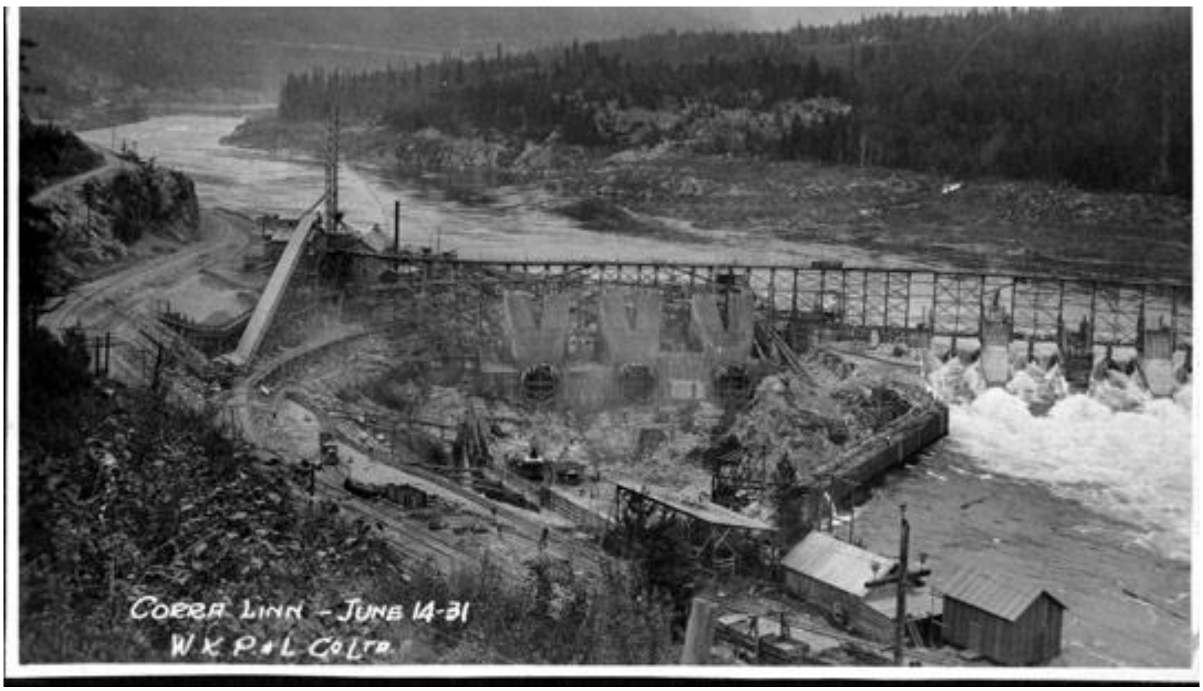
In the beginning years of the 1900s, West Kootenay Power expanded beyond serving the communities of Rossland and Trail. In 1905, due to this continued expansion, West Kootenay Power submitted a petition seeking an amendment to the original charter which would expand its service territory. Due to objections from nearby competitors, the legislature refused to pass the bill amending the charter. In 1906, West Kootenay Power bought the South Kootenay Water Power Company, securing its charter and enabling West Kootenay Power to expand its operations. By 1907 West Kootenay Power had expanded into the Boundary District and completed its new Bonnington plant on the Kootenay River (Upper Bonnington). At that time, West Kootenay Power's sphere of operations encompassed the most active mining regions of southeastern British Columbia.

*Construction of No. 2 Plant at Upper Bonnington –
Nelson City Plant visible across the river - 1906*

In 1918, Canada Copper Corporation began to develop the Copper Mountain mine near Princeton, and West Kootenay Power moved quickly to extend its transmission lines further westward. By 1920, West Kootenay Power's lines reached Copper Mountain, however the mine did not have a very successful start due to depressed metal prices and the post-war economic climate. West Kootenay Power began to search for opportunities for expansion into the South Okanagan, where efforts were beginning to irrigate the region for extensive agricultural operations. Opportunity also existed further north in Kelowna, where the existing municipal steam plant was no longer adequate to provide the electricity requirements of the municipality.

In the two decades between World War I and World War II, West Kootenay Power's rapid growth was firmly tied to the resource industry and, in particular, its most important customer Cominco's Trail smelter. In 1915, Cominco (now Teck Metals Ltd.) formally purchased West Kootenay Power, and the Company's operations continued to grow between the wars due to Cominco's expanding operations.

West Kootenay began construction of a third plant at South Slocan in September of 1926. The South Slocan plant was designed to function as West Kootenay Power's centre of operations, and to be the main control and switching station for all the company's plants along the Kootenay River. After completing the South Slocan plant in 1929, the Corra Linn dam was the next project to be built higher up the river and closer to Nelson. The Corra Linn dam was completed in 1932, and plans for a fifth plant were in development when the Depression slowed economic activity.



Construction of No. 4 Plant Corra Linn, 1931

The beginning of the Second World War in 1939 had a large impact on the operations of Cominco's new chemical and fertilizer operations at Warfield. Cominco prepared for further growth in anticipation that escalating war-time demand for munitions and explosives would exceed its current capabilities. In March 1940, West Kootenay Power added two more generators at Upper Bonnington.

In 1947, Cominco purchased the Upper Bonnington, South Slocan, and Corra Linn plants from West Kootenay Power. West Kootenay Power was left with Lower Bonnington, which was supplying more than enough power to serve utility loads. Around 1956, West Kootenay Power began to purchase small amounts of power from Cominco to supplement the output of Lower Bonnington during periods when that output was insufficient to meet utility loads. In 1981, Cominco sold the Upper Bonnington, South Slocan, and Corra Linn plants back to West Kootenay Power.

In 1987, after seventy-one years of ownership, Cominco sold West Kootenay Power to a Missouri-based company, Utilicorp United. West Kootenay Power was renamed UtiliCorp Networks Canada (British Columbia) Ltd. on October 22, 2001, and later was renamed to Aquila Networks Canada in June 2002 after its parent company was renamed to Aquila Networks.

In 2003, Fortis Inc. agreed to purchase Aquila's Alberta and BC assets. The sale was approved by the BCUC, and the Company was renamed to FortisBC Inc. (FBC) on June 1, 2004. Immediately following the acquisition by Fortis Inc., the head office of FBC was established in Kelowna, BC.

In 2005, after Commission approval Fortis Inc. purchased all issued and outstanding shares of FBC wholesale customer, Princeton Light and Power (PLP). Following further Commission approval, the shares of PLP were transferred to FBC effective January 1, 2007.

In 2012, FBC entered into an agreement with its wholesale customer, City of Kelowna, for the purchase of its utility assets. Following approval of the Commission, effective April 1, 2013, FBC acquired the utility assets of the City of Kelowna, and the approximately 14.500 City of Kelowna utility customers became direct customers of FBC.

SUMMARY

FBC, a wholly owned subsidiary of FortisBC Holdings Inc., operates in the southern interior of BC serving approximately 128,900 direct customers in communities including Kelowna, Oliver, Osoyoos, Trail, Castlegar, Creston and Rossland. In addition, FBC indirectly serves approximately 34,100 customers through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson, as well as to BC Hydro at two points. Service is provided through approximately 7,000 kilometres of transmission and distribution lines.

Appendix B2

KEY OPERATING FACTS

FBC
Annual Report Statistics
2005-2012

	2005	2006	2007	2008	2009	2010	2011	2012
Direct Customers:								
Residential Customers	86,192	89,181	93,647	95,502	96,565	97,883	98,795	98,228
Commercial Customers	10,209	10,285	11,010	11,216	11,308	11,419	11,525	11,811
Industrial Customers	39	37	38	36	33	36	39	39
Wholesale Customers	8	8	7	7	7	7	7	7
Lighting & Irrigation	3,131	2,902	3,022	2,958	2,940	2,905	2,895	2,830
Total Year End Direct Customers	**99,579**	**102,413**	**107,724**	**109,719**	**110,853**	**112,250**	**113,261**	**112,915**
Indirect Customers	49,621	49,762	46,334	47,809	48,444	48,769	49,033	49,149
Energy Sales (Normalized Actual):								
Residential (GWh)	1,070	1,091	1,160	1,221	1,293	1,224	1,260	1,220
Commercial (GWh)	568	598	636	666	672	654	652	680
Industrial (GWh)	357	344	352	252	203	234	282	291
Wholesale (GWh)	916	948	881	892	928	881	896	901
Lighting & Irrigation (GWh)	56	59	62	56	61	53	53	52
Total Energy Sales	**2,967**	**3,040**	**3,091**	**3,087**	**3,157**	**3,046**	**3,143**	**3,144**
Cost of Electricity (Normalized)								
Average Cost of Electricity Sold ($/kWh)								
O&M:								
Gross O&M Decision ($000s)	$ 39,629	$ 41,908	$ 43,093	$ 45,310	$ 46,573	47,645	53,885	54,843
Gross O&M Actual ($000s)	41,072	40,719	43,001	44,725	46,017	46,148	53,076	53,542
Capitalization Allowed ($000s)	$ (3,392)	$ (8,382)	$ (8,836)	$ (9,062)	$ (9,315)	$ (9,529)	$ (10,777)	$ (10,969)
Total Net O&M ($000s)	**$ 37,680**	**$ 32,337**	**$ 34,165**	**$ 35,663**	**$ 36,702**	**$ 36,619**	**$ 42,299**	**$ 42,574**
Headcount								
Full Time Equivalent (FTE)	431	496	532	545	540	534	528	542
Transmission & Distribution Stats:								
Distribution Lines (km)	4,992	4,978	5,468	5,547	5,560	5,603	5,630	5,648
Transmission Lines (km)	1,393	1,514	1,382	1,449	1,393	1,390	1,408	1,394
Total Transmission and Distribution Lines (km)	6,385	6,492	6,850	6,996	6,953	6,993	7,038	7,042
Total Substations	64	64	64	64	66	64	65	65
System Losses (%) - Gross Load	11.3	10.7	9.4	9.2	9.2	8.4	8.9	7.9
Peak Demand (MW) - Summer	512	554	569	537	561	554	519	551
Peak Demand (MW) - Winter	708	718	683	746	714	707	669	737
Power Supply Stats:								
Generation (GWh)	1,633	1,509	1,498	1,610	1,586	1,530	1,527	1,531
Generating Capacity (MW)	214	235	223	223	223	223	223	223
Total Power Purchases (GWh)	1,713	1,895	1,912	1,791	1,893	1,796	1,924	1,882
Total DSM Energy Saved (GWh)	23.9	23.2	28.4	27.3	29.7	28.8	36.3	31.6
System Outages:								
System Average Interruption Duration Index (SAIDI) (Normalized)	2.09	2.93	2.49	2.42	2.28	2.84	1.86	2.00
System Average Interruption Frequency Index (SAIFI) (Normalized)	3.07	4.18	1.99	2.13	1.48	2.27	1.38	1.27
Service Quality Indicators:								
Emergency Calls Responded to within 2 hours	89%	93%	92%	94%	92%	95%	92%	91%
% of Contact Centre Calls answered within 30 seconds	n/a	70%	70%	70%	70%	70%	70%	70%
Customer Satisfaction	8.1	8.5	8.6	8.6	8.6	8.8	8.7	8.4
Miscellaneous:								
Rate Base, Mid-Year ($000s)	$ 589,845	$ 671,138	$ 746,543	$ 802,566	$ 867,683	$ 945,637	$ 1,065,892	$ 1,088,470
Allowed Return	9.43%	9.20%	8.77%	9.02%	8.87%	9.90%	9.90%	9.90%

Appendix B3

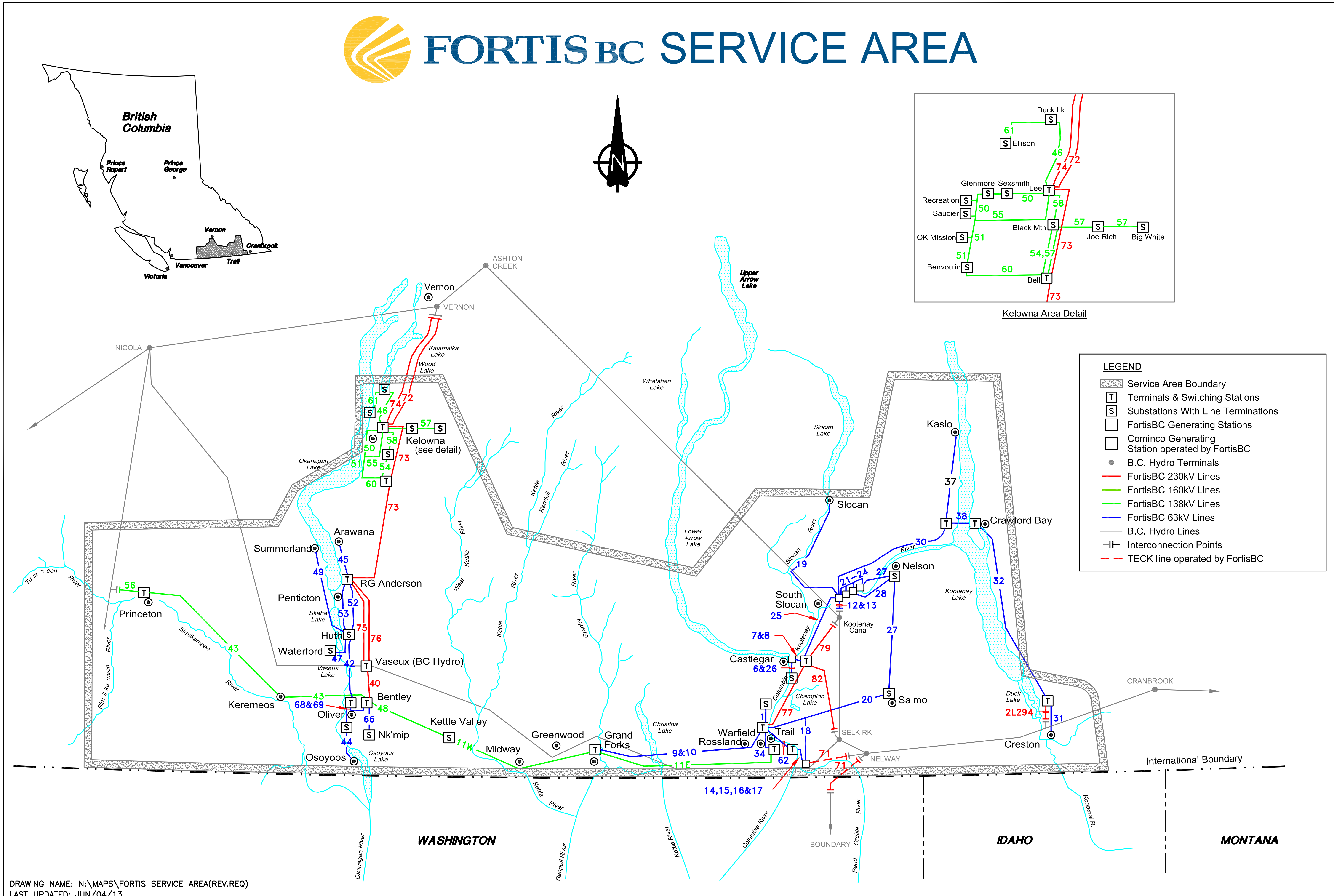
COMMUNITIES SERVED

FORTISBC SERVICE AREA:

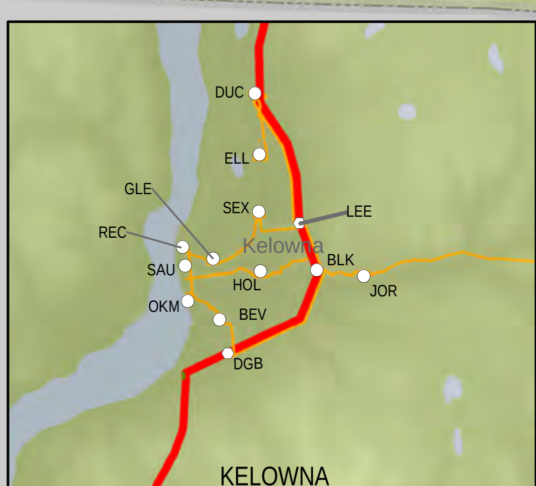
Beaverdell
Castlegar
Cawston
Christina Lake
Coalmont
Crawford Bay
Creston
Fruitvale
Grand Forks
Greenwood
Hedley
Kaslo
Kelowna
Keremeos
Midway
Montrose
Naramata
Nelson
Okanagan Falls
Oliver
Osoyoos
Penticton
Princeton
Rock Creek
Rossland
Salmo
Slocan
South Slocan
Summerland
Trail
Tulameen
Warfield
Westbridge

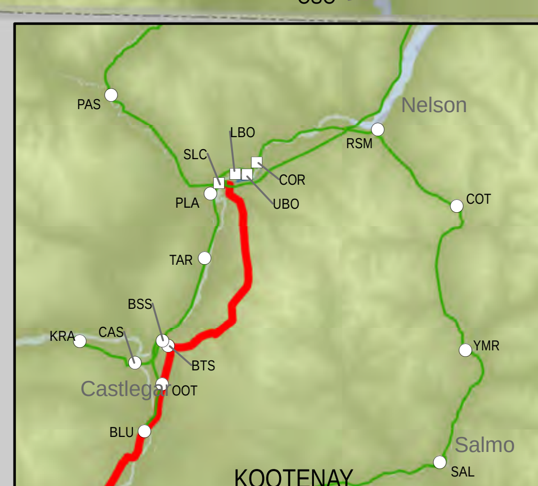
Appendix B4

SERVICE AREA MAPS


FORTIS BC SERVICE AREA
British Columbia
Prince Rupert
Prince George
Vernon
Cranbrook
Vancouver
Trail
Victoria
Kelowna Area Detail
Duck Lk
Ellison
Glenmore
Sexsmith
Lee
Recreation
Saucier
Black Mtn
Joe Rich
Big White
OK Mission
Benvoulin
Bell
LEGEND
Service Area Boundary
Terminals & Switching Stations
Substations With Line Terminations
FortisBC Generating Stations
Cominco Generating Station operated by FortisBC
B.C. Hydro Terminals
FortisBC 230kV Lines
FortisBC 160kV Lines
FortisBC 138kV Lines
FortisBC 63kV Lines
B.C. Hydro Lines
Interconnection Points
TECK line operated by FortisBC
ASHTON CREEK
VERNON
NICOLA
Kalamalka Lake
Wood Lake
Okanagan Lake
Kelowna (see detail)
Whatshan Lake
Upper Arrow Lake
Slocan Lake
Lower Arrow Lake
Kaslo
Slocan
Crawford Bay
Kootenay Lake
Nelson
South Slocan
Kootenay Canal
Castlegar
Salmo
Arawana
Summerland
RG Anderson
Penticton
Skaha Lake
Huth
Waterford
Vaseux Lake
Vaseux (BC Hydro)
Princeton
Keremeos
Bentley
Oliver
Nk'mip
Kettle Valley
Osoyoos
Osoyoos Lake
Midway
Greenwood
Grand Forks
Christina Lake
Warfield
Rossland
Champion Lake
SELKIRK
NELWAY
Duck Lake
Creston
CRANBROOK
International Boundary
BOUNDARY
WASHINGTON
IDAHO
MONTANA
DRAWING NAME: N:\MAPS\FORTIS SERVICE AREA(REV.REQ)
LAST UPDATED: JUN/04/13

FortisBC Transmission System





Substation Names

ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name
AAL	A.A. LAMBERT TERMINAL	COR	CORRA LINN PLANT #4	HER	HEARNS	OLI	OLIVER	SLC	SOUTH SLOCAN PLANT #3
ASM	A.S. MAWDSLEY TERMINAL	COT	COTTONWOOD	HOL	HOLLYWOOD	OOT	OOTISCHENIA	STC	STONEY CREEK
AWA	ARAWANA	CRA	CRAWFORD BAY	HUT	HUTH AVENUE	OSO	OSOYOOS	SUM	SUMMERLAND
BEN	BENTLEY TERMINAL	CRE	CRESTON	JOR	JOE RICHE	PAS	PASSMORE	TAR	TARRYS
BEP	BEAVER PARK	CSC	CASCADE	KAL	KALEDEN	PIN	PINE STREET	TRC	TROUT CREEK
BEV	BENVOULIN	DGB	D.G. BELL TERMINAL	KAS	KASLO	PLA	PLAYMORE	UBO	UPPER BONNINGTON PLANT #2
BLK	BLACK MOUNTAIN	DUC	DUCK LAKE	KER	KEREMEOS	PRI	PRINCETON	VAL	VALHALLA
BLU	BLUEBERRY	ELL	ELLISON	KET	KETTLE VALLEY	REC	RECREATION	VAS	VASEUX TERMINAL
BSS	BRILLIANT SWITCHING (CPC)	ESS	EMERALD SWITCHING (TECK)	KRA	KRAFT	RGA	R.G. ANDERSON TERMINAL	WAN	WANETA PLANT #5 (TECK)
BTS	BRILLIANT TERMINAL (CPC)	FRU	FRUITVALE	LBO	LOWER BONNINGTON PLANT #1	RSM	ROSEMONT SWITCHING	WAT	WATERFORD
BWS	BIG WHITE	GFT	GRAND FORKS TERMINAL	LEE	F.A. LEE TERMINAL	RUC	RUCKLES	WEB	WEST BENCH
CAS	CASTLEGAR	GLE	GLENMORE	NKM	NK'MIP	SAL	SALMO	WES	WESTMINSTER
CHR	CHRISTINA LAKE	GLM	GLENMERRY	OKF	O.K. FALLS	SAU	SAUCIER	WTS	WARFIELD TERMINAL
COF	COFFEE CREEK	HED	HEDLEY	OKM	OKANAGAN MISSION	SEX	SEXSMITH	YMR	YMIR

Appendix C1

SUMMARY OF PAST DIRECTIVES

The following table summarizes Directives from previous Commission Decisions relevant to this 2014 – 2018 Revenue Requirements Application.

No.	BCUC Order and Directive	Details	Status and Comments	Application Reference
April 18, 2013 BCUC Letter 2014 Revenue Requirements Application Productivity Improvements in a Performance Based Rate Setting Environment				
1		FEU and FortisBC are to propose a PBR methodology and explain how it addresses the limitations in the various PBR methodologies, and will achieve a productivity improvement culture.	A PBR Plan is proposed in this Application.	Section B
G-146-12 – Tariff Supplement No. 4(ii) Wholesale Service Agreement				
2	Directive 3	**Power Factor:** FortisBC is to submit a report as an appendix in its next revenue requirement application on the power factor of each of the Wholesale Service agreements included under Tariff Supplement Number 4. If the power factor is below 95 percent FortisBC is to provide details regarding the extent to which the power factor is less than 95 percent.	Wholesale Power Factor Report is included in this Application.	Appendix C5
G-110-12 – FBC 2012 – 2013 Revenue Requirements Application and Review of 2012 Integrated System Plan				
3	Directive 1, Page 25	With respect to the use of the 1 in 20 forecast, the Commission Panel directs FortisBC in its next RRA to undertake both a 1 in 10 and a 1 in 20 peak forecast and provide evidence as to the relative merits of each as a planning tool.	A discussion of 1 in 10 and 1 in 20 forecasts for capital planning is included in this Application.	Appendix E3
4	Directive 10, Page 44	**Workforce Planning** FortisBC is directed to prepare a workforce action plan to address this issue covering, at a minimum, the next 5 year period and file it with the Commission no later than December 1, 2012.	FBC filed the report on Nov. 30, 2012.	-

No.	BCUC Order and Directive	Details	Status and Comments	Application Reference
5	Directive 11, Page 47	**Integration with FEI:** The Commission Panel is not prepared to be overly prescriptive at this time and will allow FortisBC to continue to proceed on the timeline it has proposed. However, we expect the issue to be fully explored and reflected in filings no later than 2014.	Integration of FBC and FEI is discussed in this Application.	Section A3
6	Directive 14, Page 58	**Executive Compensation:** The Commission Panel directs FortisBC to provide benchmarking information on all elements of its executive compensation in the next RRA.	Benchmarking report filed in confidence.	Appendix C2
7	Directive 15, Page 59	**Pensionable Benefits:** The Commission Panel directs FortisBC to include information as to current practice of their reference group of companies with regard to the inclusion of incentive payments in pensionable benefits for all groups of employees in its next RRA.	The requested information has been provided.	Appendix C3
8	Directive 21, Page 72	**Capitalized Overhead:** FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time.	A report by the Company's external auditors is included in this Application.	Appendix F3
9	Directive 22, Page 75	**Capitalized Overhead:** The Commission Panel directs FortisBC to meet with Commission staff following completion of the external audit opinion on its capitalized overhead methodology to review other options which may better reflect changes in the amount of capital being expended in a given year.	FBC met with Commission staff prior to filing the Application.	-
10	Directive 24, Page 77	**Direct Overheads:** The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification.	A report by the Company's external auditors is included in this Application.	Appendix F3

No.	BCUC Order and Directive	Details	Status and Comments	Application Reference
11	Directive 47, Page 134	**Demand Side Management:** The Commission 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.	FBC's 2013 – 2015 Monitoring and Evaluation Plan is included in this Application.	Appendix H, Attachment 3
12	Directive 51, Page 141	**Demand Side Management:** The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.	FBC's 2014-2018 DSM Plan reports on integration of DSM programs.	Appendix H, Attachment 1 Section 1.6
Load Forecast Technical Committee Report, Exhibit B-16 of 2012-2013 Revenue Requirements Application				
13	Pages 2-3	**Load Forecast:** The Company undertook certain commitments for the preparation of its 2014 Load Forecast.	The commitments identified in the report have been addressed.	Appendix E2, Section E
E-15-12 – FBC Capacity Purchase Agreement				
14		**Rate Smoothing Mechanism:** FortisBC is directed to develop a rate smoothing proposal for the Commission's approval either through a separate submission or with the next Revenue Requirements Application.	A 5 year Rate Stabilization Deferral Mechanism is proposed in this Application.	Sections B7 and D4.3.1.
G-117-11 – FortisBC Utilities Application to Adopt US Generally Accepted Accounting Principles				
15	Directive 4	**Canadian GAAP Reconciliation:** Each of Fortis BC Utilities' entities adopting US GAAP shall prepare a reconciliation of amounts reported for regulatory accounting to those amounts that would otherwise be reported under 2011 Canadian GAAP. This reconciliation should be included in annual reports and revenue requirements applications up to December 31, 2014.	A reconciliation of 2012 financial statements is included in this Application.	Appendix F5

No.	BCUC Order and Directive	Details	Status and Comments	Application Reference
G-193-08 – FBC 2009 Revenue Requirements and PBR Plan Extension				
16	Appendix A, Page 10	**Performance Standards** The 2012 oral hearing or the next Performance Based Rate Application review process will examine the criteria for meeting performance Standards.	A PBR Plan is proposed in this Application.	Section B
G-147-07 – FBC 2008 Revenue Requirements				
17	Appendix A, Page 5	**Related Party Transactions:** Disclosure of related party transactions will be a standard item for future revenue requirements applications.	FBC's 2012 Related Party Transactions Report is included in this Application.	Appendix C4

Appendix C2

EXECUTIVE COMPENSATION BENCHMARKING

FILED CONFIDENTIALLY

Appendix C3

INCENTIVE COMPENSATION REPORT

TOWERS WATSON

Stephen Butterfield
Senior Consultant

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Vancouver, British Columbia
V6E 4A6

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stephen.butterfield@towerswatson.com
towerswatson.com

June 25, 2013

Ms. Jody Drope
Chief Human Resources Officer
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Dear Jody,

As requested, we are writing to provide information in response to the British Columbia Utilities Commission (BCUC) directive on the practices of various employers with respect to the inclusion of incentive pay in pensionable earnings. We understand that FortisBC provides incentive pay only to non-union employees and a small number of Customer Service employees who are affiliated with the COPE.

Information was obtained from two sources:

- Towers Watson's Benefits Data Source
- A custom survey undertaken in 2009 by Towers Watson on behalf of FortisBC.

Benefits Data Source

Towers Watson maintains a database on the detailed provisions of the pension and benefit programs provided to non-union employees of participating companies (known as the Benefits Data Source – BDS). Over 550 companies participate in the BDS. In return for their participation, companies can access the information in the BDS. Annually, Towers Watson requests that all participating companies confirm or update the information in the BDS. FortisBC has previously selected the following 22 participating companies to be part of their "Peer Group":

- ATCO Group
- BC Hydro
- Canadian Pacific Railway
- Capital Power Corporation
- Catalyst Paper
- Chevron
- ConocoPhillips
- Enbridge Gas Distribution
- ENMAX
- EPCOR
- FortisAlberta
- Insurance Corporation of BC
- Manitoba Hydro
- Methanex
- Nexen
- Spectra Energy
- Suncor
- Teck Resources
- TELUS
- Trans Alta

- Finning (Canada)
- TransCanada Pipeline

Among these organizations, based on year-end 2011 data:

- 64% (n=14) include the entire (n=10) or a portion (n=4) of incentive pay in pensionable earnings; and
- 36% (n=8) do not include incentive pay in pensionable earnings.

Of the 4 organizations that include a portion of incentive pay in pensionable earnings, the limit is expressed as either a percentage of salary (i.e., 15% or 20% salary) or as a percentage of incentive pay (i.e., 45% or 50% of incentive pay).

Customized Survey

In 2009, Towers Watson undertook a customized survey on behalf of FortisBC to obtain certain information with respect to incentive pay for 15 regulated utilities. The 15 utilities surveyed were:

- AltaLink
- ATCO Electric
- BC Hydro and Power Authority
- BC Transmission
- Enbridge Gas Distribution
- Enbridge Pipelines
- ENMAX
- FortisAlberta
- FortisBC
- Insurance Corporation of BC
- Kinder Morgan Canada
- Pacific Northern Gas
- Spectra Energy – Union Gas
- Spectra Energy – Westcoast
- TransCanada Pipeline

One of the questions asked in the customized survey was whether incentive pay was included in pensionable earnings. The findings among these regulated utilities were:

- 86% (n=13) include the entire (n=11) or a portion (n=2) of incentive pay in pensionable earnings; and
- 13% (n =2) do not include incentive pay in pensionable earnings.

Of the 2 utilities that include a portion of incentive pay in pensionable earnings the limit is 15% of base salary.

Although the survey was conducted in 2009, changes to these kinds of plan provisions happen very infrequently and we expect that a survey conducted today would result in substantially similar findings.

We trust the BCUC finds this information helpful. Please feel free to contact us if you have any questions.

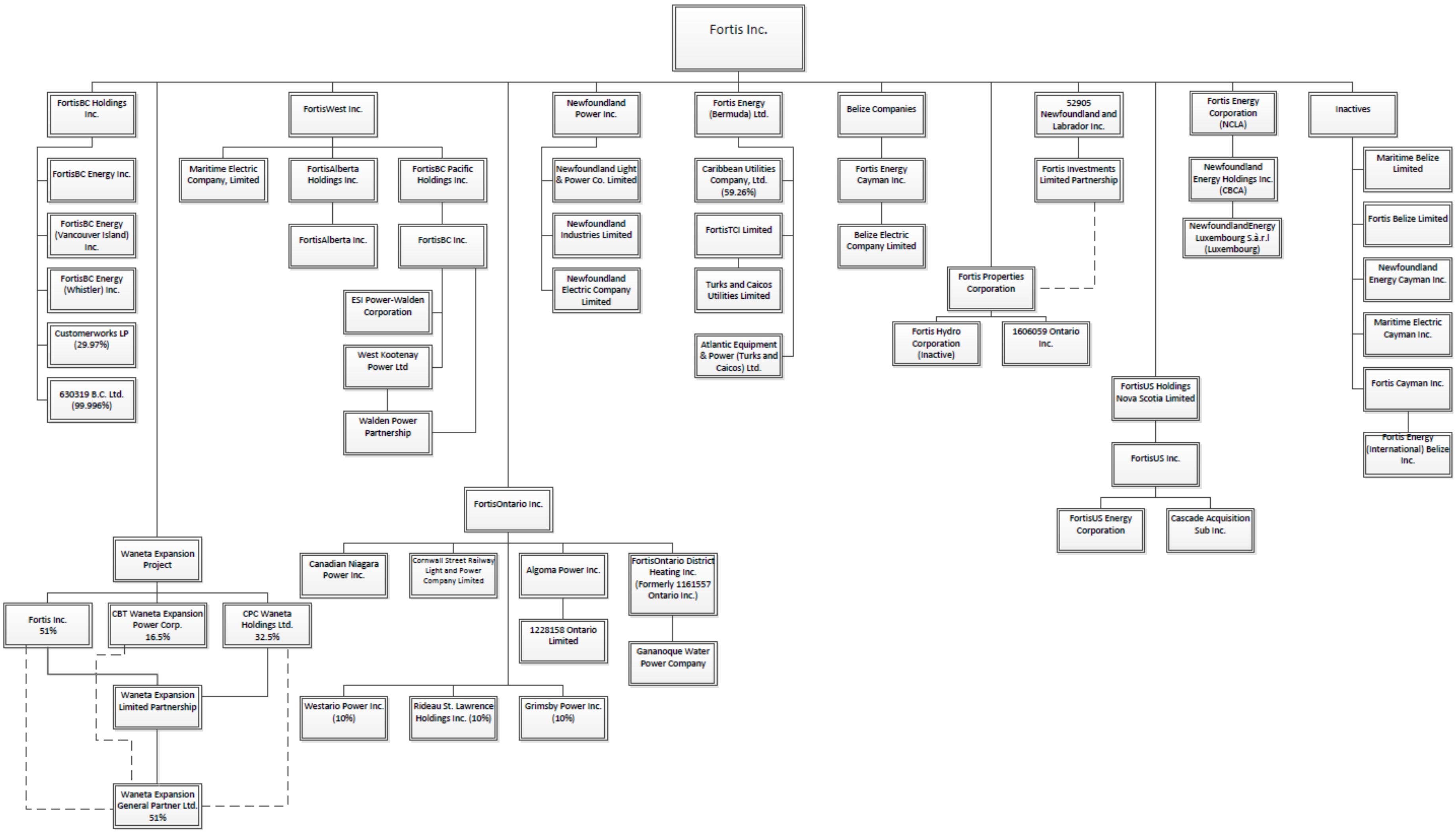
Sincerely,

Stephen J. Butterfield

Appendix C4

RELATED PARTY TRANSACTIONS

1. ORGANIZATIONAL CHART – AFFILIATED ENTITIES OF FORTISBC INC. (EFFECTIVE APRIL 1, 2013)



2. LIST OF RELATED PARTIES WITH WHOM FORTISBC TRANSACTED BUSINESS

The following is a list of related parties with whom FortisBC transacted business in the year ending December 31, 2012, including the business address, list of officers and directors as at December 31, 2012, and a description of the related party's business activities.

Fortis Inc.
The Fortis Building
Suite 1201, 139 Water Street
St. John's, NL
A1B 3T2

Directors:
David G. Norris
Peter E. Case
Frank J. Crothers
Ida J. Goodreau
Douglas J. Haughey
H. Stanley Marshall
John S. McCallum
Harry McWatters
Ronald D. Munkley
Michael A. Pavey
Roy P. Rideout

Officers:

H. Stanley Marshall	*President and CEO*
Barry V. Perry	*Vice President, Finance and CFO*
Ronald W. McCabe	*Vice President, General Counsel and Corporate Secretary*
Donna G. Hynes	*Assistant Secretary and Manager, Investor and Public Relations*

Description of Business: Fortis Inc. is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and two Caribbean countries and a natural gas utility in British Columbia. Fortis Inc. owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upstate New York. It also owns hotels and commercial office and retail space in Canada.

FortisAlberta Inc.
320-17th Avenue S.W.
Calgary, AB
T2S 2V1

Directors:
Judith J. Athaide
Tracey C. Ball
Mary Cameron
William J. Daley
Al H. Duerr
Douglas Haughey
Joanne R. Lemke
Barry V. Perry
Donald J. (Jim) Turner
Karl W. Smith
John C. Walker

Officers:

Karl W. Smith	*President and CEO*
Cam Aplin	*Vice President, Field Operations*
Annette Iwasaki	*Vice President, Human Resources and Corporate Communications*
Mike Pashak	*Vice President, Customer Service*
Phonse Delaney	*Executive Vice President, Operations, Engineering and Information Technology*
Ian Lorimer	*Vice President, Finance and CFO*
Karl Bomhof	*General Counsel and Corporate Secretary*

Description of Business: FortisAlberta Inc. is an indirect, wholly-owned subsidiary of Fortis Inc. The Corporation operates a largely rural, approximately 116,000 kilometre, low-voltage distribution network in central and southern Alberta, which serves approximately 508,000 electricity customers. In 2012, FortisAlberta distributed approximately 24,000 gigawatt hours (GWh) of electricity. This includes those to customers within its service area that are connected directly to the transmission grid. FortisAlberta is regulated by the Alberta Utilities Commission.

Newfoundland Power Inc.
55 Kenmount Road
St. John's, NL
A1B 3P6

Directors:
Frank Davis
Nora Duke
J.F. Richard Hew
Earl Ludlow
Karen McCarthy
Edward Murphy
Fred O'Brien
Bruce Simmons
Anne Whelan
Jo Mark Zurel

Officers:

Earl Ludlow	*President and CEO*
Jocelyn Perry	*Vice President, Finance and CFO*
Gary Smith	*Vice President, Customer Operations and Engineering*
Peter Alteen	*Vice President, Regulation and Planning; General Counsel and Corporate Secretary*

Description of Business: Newfoundland Power Inc., a wholly-owned subsidiary of Fortis Inc., operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves over 251,000 customers in the province and had electricity sales of approximately 5,652 GWh in 2012. Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities.

FortisBC Holdings Inc.
10th Floor
1111 West Georgia Street
Vancouver, BC
V6E 4M3

Directors:
Harold Calla
Brenda Eaton
Ida J. Goodreau
H. Stanley Marshall
Barry V. Perry
Linda S. Petch
David R. Podmore
Christopher F. Scott
Karl W. Smith
John C. Walker
Janet P. Woodruff

Officers:

John C. Walker	*President and CEO*
Roger Dall'Antonia	*CFO and Treasurer*
David Bennett	*Vice President, Operations Support, General Counsel and Corporate Secretary*
Debra G. Nelson	*Assistant Corporate Secretary*

Description of Business: FortisBC Holdings Inc., a wholly-owned subsidiary of Fortis Inc., is the parent company of the regulated FortisBC Gas companies. FortisBC Holdings, together with its subsidiaries, serve approximately 945,000 customers. In addition to natural gas transmission and distribution operations, FortisBC Holdings owns interests in several smaller businesses and is a leading provider of alternative energy systems.

FortisBC Energy Inc.
10th Floor
1111 West Georgia Street
Vancouver, BC
V6E 4M3

Directors:

Harold Calla
Brenda Eaton
Ida J. Goodreau
H. Stanley Marshall
Harry McWatters
Barry V. Perry
Linda S. Petch
David R. Podmore
Karl W. Smith
John C. Walker

Officers:

John C. Walker	*President and CEO*
Dwain A. Bell	*Vice President, Operations*
David Bennett	*Vice President, Operations Support, General Counsel and Corporate Secretary*
Michele Leeners	*Vice President, Finance and CFO*
Roger Dall'Antonia	*Vice President, Strategic Planning, Corporate Development and Regulatory Affairs*
Cynthia Des Brisay	*Vice President, Energy Supply and Resource Development*
Tom A. Loski	*Vice President, Customer Service*
Douglas L. Stout	*Vice President, Energy Solutions and External Relations*
Michael Mulcahy	*Executive Vice President, Human Resources, Customer and Corporate Services*
Doyle Sam	*Executive Vice President, Network Services, Engineering and Generation*
Debra G. Nelson	*Assistant Corporate Secretary*

Description of Business: FortisBC Energy Inc., an indirect, wholly-owned subsidiary of Fortis Inc., is a regulated utility providing natural gas transmission and distribution services to approximately 841,000 customers in more than 100 communities across British Columbia. In 2012, FortisBC Energy had gas sales of approximately 179 petajoules (PJs). FortisBC Energy is regulated by the British Columbia Utilities Commission.

FortisBC Pacific Holdings Inc.
25th Floor
700 West Georgia Street
Vancouver, BC
V7Y 1B3

Directors:
John C. Walker
David Bennett
Michele Leeners
Doyle Sam

Officers:

John C. Walker	*President and CEO*
Michele Leeners	*Vice President, Finance and CFO*
Doyle Sam	*Executive Vice President, Network Services, Engineering and Generation*
David Bennett	*Corporate Secretary*
Debra G. Nelson	*Assistant Secretary*

Description of Business: FortisBC Pacific Holdings Inc., an indirect, wholly-owned subsidiary of Fortis Inc., is a British Columbia company that is the parent company of FortisBC Inc.

Walden Power Partnership
Suite 100, 1975 Springfield Road
Kelowna, BC
V1Y 7V7

Description of Business: Walden Power Partnership is the owner of a non-regulated 16 MW run-of-river hydroelectric power plant near Lillooet, BC. The partnership is between FortisBC Inc. and West Kootenay Power Limited.

Waneta Expansion Limited Partnership
25th Floor
700 West Georgia Street
Vancouver, BC
V7Y 1B3

Description of Business: The Waneta Expansion Limited Partnership is a limited liability partnership between Columbia Power Corporation, Columbia Basin Trust, and Fortis Inc. The purpose of the Partnership is to design, build, own and operate the Waneta Expansion hydro-electric generating facility on the Pend d'Oreille River south of Trail, British Columbia.

3. RELATED PARTY OPERATING TRANSACTIONS SUMMARY

The following is a summary of operating transactions between FortisBC and its affiliates for the year ending December 31, 2012, containing a general description of the transactions and services, the parties involved and the approximate aggregate value.

1. Transactions with **Fortis Inc.**

Transactions charged by Fortis Inc.	
Transaction Type	**Amount ($)**
Compensation Recoveries (Regulated)	789,000
Compensation Recoveries (Non-Regulated)	549,000
Corporate Governance Costs	479,000
Consulting & Legal Costs	229,000
Audit & Other Filing Costs	228,000
Pension Related Recoveries	30,000
Other Recoverable Corporate Expenses	169,000
2012 Total	2,473,000

2. Transactions with **FortisAlberta Inc.**

Transactions charged to FortisAlberta	
Transaction Type	**Amount ($)**
Pension Related Recoveries	34,000
2012 Total	34,000

Transactions charged by FortisAlberta	
Transaction Type	**Amount ($)**
Metering Services	73,000
Material & Equipment Purchase (Capital)	39,000
Employee Services	14,000
Membership Fees	5,000
2012 Total	131,000

3. Transactions with **Newfoundland Power Inc.**

Transactions charged by Newfoundland Power	
Transaction Type	**Amount ($)**
Software Licenses	27,000
Labour & Travel Expenses	17,000
Share of Conference Board of Canada Subscription	2,000
2012 Total	46,000

4. Transactions with **FortisBC Holdings Inc.**

Transactions charged to FortisBC Holdings Inc.	
Transaction Type	**Amount ($)**
Labour & Travel Expenses[1]	504,000
Corporate Governance Costs	1,000
2012 Total	505,000

Transactions charged by FortisBC Holdings Inc.	
Transaction Type	**Amount ($)**
Labour & Travel Expenses[1]	416,000
Corporate Governance Costs	158,000
Insurance Services	14,000
2012 Total	588,000

1 Consists primarily of Executive, Legal, and Internal Audit charges.

5. Transactions with **FortisBC Energy Inc.**

Transactions charged to FortisBC Energy Inc.	
Transaction Type	**Amount ($)**
Labour & Travel Expenses	942,000
Executive Salary	824,000
Sale of Power (Tariff Sales)	452,000
Low Income Direct Install & Other Programs	144,000
2012 Total	2,362,000

Transactions charged by FortisBC Energy Inc.	
Transaction Type	**Amount ($)**
Labour & Travel Expenses	1,380,000
Rental of Springfield Road Office	247,000
Long Service Recognition Expenses	25,000
Purchase of Natural Gas (Tariff Sales)	9,000
2012 Total	1,661,000

6. Transactions with **FortisBC Pacific Holdings Inc. (FPHI)**

Transactions charged to FPHI	
Transaction Type	**Amount ($)**
O&M and Transfer Pricing Charged to FPHI	8,824,000
Interest Charged to FPHI	22,000
2012 Total	8,846,000

7. Transactions with **Walden Power Partnership**

Transactions charged to Walden	
Transaction Type	**Amount ($)**
O&M and Transfer Pricing Charged to Walden	175,000
2012 Total	175,000

8. Transactions with **Waneta Expansion Limited Partnership (WELP)**

Transactions charged to WELP	
Transaction Type	**Amount ($)**
Corporate Governance Costs	2,000
2012 Total	2,000

4. RELATED PARTY FINANCIAL TRANSACTIONS SUMMARY

The following is a summary of financial transactions provided between FortisBC and its affiliates.

FortisBC Inc. Affiliate Party Financial Transactions January 1, 2012 to December 31, 2012				
Date	**Related Party**	**Terms**	**Capital Transactions ($000s)**	**Financing Transactions ($000s)**
28-Feb-12	FPHI	Dividend Payment	(4,500)	-
30-May-12	FPHI	Dividend Payment	(4,500)	-
30-Aug-12	FPHI	Dividend Payment	(5,000)	-
15-Oct-12	FPHI	Dividend Payment	(1,000)	-
29-Nov-12	FPHI	Dividend Payment	(10,000)	-

Appendix C5

WHOLESALE POWER FACTOR REPORT

WHOLESALE POWER FACTOR REPORT

On September 30, 2008, as a requirement of Order G-101-08, FortisBC filed its report on raising the power factor level from 90 percent to 95 percent in its wholesale agreements with the City of Penticton (Penticton), the District of Summerland (Summerland), the City of Kelowna (Kelowna), the City of Grand Forks (Grand Forks), and the Corporation of the City of Nelson (Nelson). By letter dated October 16, 2008, the British Columbia Utilities Commission (BCUC or the Commission) accepted the report.

By Letter L-9-09, dated January 29, 2009, the Commission directed FBC to update Clause 6.10 of each wholesale customer's wholesale agreement to require a power factor of no less than 95 percent upon the renewal date of each agreement. As stated in its letter to the Commission dated March 28, 2013, FBC is currently in the process of renewing wholesale agreements reflecting the power factor requirement of no less than 95 percent with Penticton, Summerland, Nelson and Grand Forks. FBC expects to have renewed agreements with each of its wholesale customers by the end of 2013.

On October 12, 2012, the Commission issued Order G-146-12, approving FortisBC Inc.'s (FBC) new Wholesale Agreement with the City of Kelowna[1] and directing FBC to submit a report as an appendix in its next Revenue Requirement Application on the power factor of each of the wholesale customers, and where any power factor is below 95 percent, details should be provided regarding the extent to which the power factor is less than 95 percent.

The revenue metering data and calculated power factors (ratio of kW to kVA) for each of the four current wholesale customers at each point of delivery is provided in the following report for the period April 2011 to March 2013.

There have been sporadic excursions at some delivery points below the 95 percent power factor threshold directed by the Commission in Letter L-9-09. There is no indication of ongoing power factor issues at these locations, but FBC has raised this concern with the relevant wholesale customers and will continue to monitor the situation. If low power factor readings persist or worsen then the customer may be required to add additional reactive compensation equipment (at the customer's cost) to improve the power factor.

[1] Effective March 31, 2013, FBC acquired the utility assets of the City of Kelowna. As a result, the City of Kelowna is no longer a wholesale customer of FBC.

1 City of Penticton

	Meter	Date	kW	kVA	PF
Huth 8 kVA	997521	4/15/2013	6776.00	6776.00	1.00
		3/19/2013	7640.00	7640.00	1.00
		2/12/2013	8928.00	8929.10	1.00
		1/22/2013	10008.00	10008.92	1.00
		12/19/2012	9396.00	9396.28	1.00
		11/27/2012	8820.00	8820.71	1.00
		10/24/2012	7548.00	7548.01	1.00
		9/19/2012	6520.00	6534.56	1.00
		8/8/2012	8508.00	8612.26	0.99
		7/18/2012	8672.00	8814.04	0.98
		6/21/2012	6624.00	6662.58	0.99
		5/16/2012	9996.00	10096.36	0.99
		4/2/2012	7280.00	7280.00	1.00
		3/1/2012	8484.00	8484.02	1.00
		2/27/2012	8840.00	8840.00	1.00
		1/18/2012	10928.00	10929.69	1.00
		12/13/2011	9816.00	9820.58	1.00
		11/16/2011	9604.00	9617.64	1.00
		10/26/2011	7548.00	7554.12	1.00
		9/23/2011	12068.00	12467.80	0.97
		8/24/2011	8192.00	8320.38	0.98
		7/7/2011	7620.00	7666.16	0.99
		6/29/2011	6912.00	6939.75	1.00
		5/17/2011	8840.00	8840.00	1.00
		4/13/2011	10896.00	10938.21	1.00

	Meter	Date	kW	kVA	PF
Huth 13 kVA	1005217	4/15/2013	4302.00	4343.31	0.99
		3/6/2013	4759.20	4798.85	0.99
		2/12/2013	5086.80	5130.21	0.99
		1/22/2013	5594.40	5641.47	0.99
		12/19/2012	5522.40	5565.94	0.99
		11/27/2012	5054.40	5094.86	0.99
		10/24/2012	4586.40	4634.50	0.99
		9/4/2012	4626.00	4748.77	0.97
		8/20/2012	5986.80	6215.47	0.96
		7/13/2012	6037.20	6267.88	0.96
		6/28/2012	4813.20	4949.14	0.97
		5/15/2012	4690.80	4807.93	0.98
		4/2/2012	4597.20	4644.16	0.99
		3/12/2012	4986.00	5032.21	0.99
		2/7/2013	5187.60	5229.26	0.99
		1/18/2012	6145.20	6191.97	0.99
		12/13/2011	5562.00	5600.04	0.99
		11/16/2011	5277.60	5334.05	0.99
		10/21/2011	13482.00	13643.83	0.99
		9/23/2011	5302.80	5492.02	0.97
		8/24/2011	5904.00	6127.97	0.96
		7/6/2011	5796.00	6016.21	0.96
		6/22/2011	4921.20	5067.68	0.97
		5/20/2011	4262.40	4356.38	0.98
		4/6/2011	4600.80	4648.24	0.99

	Meter	Date	kW	kVA	PF
Westminster	924177	4/12/2013	13184.00	13185.97	1.00
		3/6/2013	15360.00	15360.09	1.00
		2/4/2013	17204.00	17206.41	1.00
		1/22/2013	20040.00	20049.34	1.00
		12/10/2012	20796.00	20796.00	1.00
		11/27/2012	19584.00	19584.00	1.00
		10/1/2012	19276.00	19276.07	1.00
		9/4/2012	14616.00	14666.83	1.00
		8/20/2012	19820.00	20066.56	0.99
		7/13/2012	19876.00	20155.34	0.99
		6/29/2012	14064.00	14112.42	1.00
		5/3/2012	16948.00	16948.00	1.00
		4/26/2012	20176.00	20176.00	1.00
		3/12/2012	18264.00	18264.04	1.00
		2/7/2012	20344.00	20344.00	1.00
		1/18/2012	27128.00	27136.22	1.00
		12/13/2011	21992.00	21992.01	1.00
		11/16/2011	21416.00	21416.03	1.00
		10/25/2011	22312.00	22312.00	1.00
		9/12/2011	16732.00	16890.98	0.99
		8/29/2011	18872.00	19111.48	0.99
		7/6/2011	18324.00	18564.09	0.99
		6/1/2011	17100.00	17100.00	1.00
		5/19/2011	16220.00	16223.16	1.00
		4/30/2011	20168.00	20171.81	1.00

	Meter	Date	kW	kVA	PF
Waterford	997528	4/2/2013	12042.00	12169.65	0.99
		3/6/2013	11634.00	11694.50	0.99
		2/4/2013	13392.00	13463.53	0.99
		1/22/2013	15468.00	15538.26	1.00
		12/19/2012	14874.00	14946.46	1.00
		11/6/2012	14946.00	15050.44	0.99
		10/24/2012	11016.00	11087.14	0.99
		9/9/2012	10950.00	11325.47	0.97
		8/5/2012	15816.00	16502.42	0.96
		7/13/2012	15414.00	16119.31	0.96
		6/29/2012	10679.41	10679.41	1.00
		5/15/2012	10050.00	10333.99	0.97
		4/2/2012	10686.00	10760.73	0.99
		3/2/2012	12390.00	12462.68	0.99
		2/7/2012	13890.00	13972.70	0.99
		1/18/2012	18204.00	18282.46	1.00
		12/13/2011	15432.00	15508.25	1.00
		11/7/2011	18360.00	18475.65	0.99
		10/26/2011	15582.00	15680.86	0.99
		9/12/2011	11760.00	12177.68	0.97
		8/9/2011	14364.00	14970.51	0.96
		7/6/2011	13752.00	14356.48	0.96
		6/22/2011	10284.00	10632.53	0.97
		5/2/2011	9600.00	9677.72	0.99
		4/19/2011	10272.00	10354.19	0.99

	Meter	Date	kW	kVA	PF
Carmi	997520	4/9/2013	14289.00	14352.63	1.00
		3/22/2013	13833.00	13902.26	1.00
		2/4/2013	15060.00	15144.65	0.99
		1/2/2013	17295.00	17368.76	1.00
		12/13/2012	16341.00	16411.36	1.00
		11/26/2012	13209.00	13346.95	0.99
		10/23/2012	10401.00	10588.35	0.98
		9/6/2012	9960.00	10282.74	0.97
		8/20/2012	13362.00	13982.46	0.96
		7/13/2012	12882.00	13420.92	0.96
		6/28/2012	9669.00	9923.95	0.97
		5/10/2012	10074.00	10251.98	0.98
		4/2/2012	11211.00	11379.84	0.99
		3/12/2012	11985.00	12159.90	0.99
		2/8/2012	12648.00	12837.74	0.99
		1/18/2012	15750.00	15909.06	0.99
		12/13/2011	14022.00	14181.51	0.99
		11/21/2011	12807.00	12941.36	0.99
		10/26/2011	11253.00	11513.62	0.98
		9/23/2011	21717.00	22133.19	0.98
		8/9/2011	13203.00	13838.66	0.95
		7/6/2011	12381.00	12933.84	0.96
		6/13/2011	10962.00	11189.32	0.98
		5/20/2011	9513.00	9835.00	0.97
		4/15/2011	20268.00	20304.38	1.00

The City of Penticton maintained a power factor equal to or greater than 0.95 in all months.

District of Summerland

	Meter	Date	kW	kVA	PF
Summerland	935171	4/8/2013	9633.00	9775.32	0.99
		3/16/2013	10944.00	11070.83	0.99
		2/3/2013	11862.00	11987.64	0.99
		1/22/2013	13731.00	13860.87	0.99
		12/19/2012	13428.00	13557.45	0.99
		11/26/2012	12315.00	12443.26	0.99
		10/16/2012	11934.00	12160.10	0.98
		9/24/2012	11160.00	11433.10	0.98
		8/5/2012	11628.00	12152.30	0.96
		7/13/2012	11670.00	12210.00	0.96
		6/6/2012	8217.00	8378.67	0.98
		5/10/2012	10896.00	11074.44	0.98
		4/2/2012	10665.00	10812.85	0.99
		3/1/2012	11871.00	12022.41	0.99
		2/7/2012	12987.00	13136.62	0.99
		1/18/2012	16395.00	16532.01	0.99
		12/13/2011	13731.00	13869.20	0.99
		11/16/2011	13242.00	13390.10	0.99
		10/27/2011	10830.00	11017.69	0.98
		9/19/2011	10248.00	10488.89	0.98
		8/5/2011	10773.00	11300.11	0.95
		7/7/2011	10026.00	10524.59	0.95
		6/1/2011	10857.00	11069.78	0.98
		5/12/2011	11280.00	11482.14	0.98
		4/19/2011	10203.00	10350.30	0.99

	Meter	Date	kW	kVA	PF
Trout Creek	916784	4/8/2013	3734.40	3761.56	0.99
		3/4/2013	4358.40	4384.23	0.99
		2/8/2013	4768.80	4799.28	0.99
		1/22/2013	5452.80	5484.93	0.99
		12/31/2012	5289.60	5321.92	0.99
		11/26/2012	4792.80	4821.53	0.99
		10/16/2012	4874.40	4932.68	0.99
		9/21/2012	3040.80	3040.80	1.00
		8/5/2012	4264.80	4408.40	0.97
		7/13/2012	4096.80	4236.76	0.97
		6/7/2012	3079.20	3101.02	0.99
		5/3/2012	3182.40	3209.37	0.99
		4/2/2012	4099.20	4125.02	0.99
		3/1/2012	4447.20	4468.60	1.00
		2/27/2012	5100.00	5123.45	1.00
		1/18/2012	6506.40	6546.91	0.99
		12/13/2011	5234.40	5269.78	0.99
		11/20/2011	5193.60	5228.97	0.99
		10/26/2011	3849.60	3883.71	0.99
		9/20/2011	3470.40	3544.30	0.98
		8/5/2011	3842.40	3978.58	0.97
		7/30/2011	3578.40	3703.69	0.97
		6/22/2011	2671.20	2735.67	0.98
		5/2/2011	3213.60	3241.56	0.99
		4/19/2011	3871.20	3903.56	0.99

The District of Summerland maintained a power factor equal to or greater than 0.95 in all months.

City of Grand Forks

	Meter	Date	kW	kVA	PF
Ruckles	924183	4/16/2013	1776.00	1776.00	1.00
13 kVA		3/4/2013	2180.40	2180.40	1.00
		2/7/2013	2324.40	2324.40	1.00
		1/15/2013	2696.40	2696.40	1.00
		12/19/2012	2702.40	2702.40	1.00
		11/28/2012	2390.40	2390.40	1.00
		10/24/2012	2143.20	2143.20	1.00
		9/25/2012	1827.60	1828.20	1.00
		8/13/2012	1922.40	1924.29	1.00
		7/14/2012	3213.60	3280.67	0.98
		6/6/2012	1556.40	1556.40	1.00
		5/3/2012	1623.60	1623.60	1.00
		4/5/2012	1890.00	1890.00	1.00
		3/1/2012	2239.20	2239.20	1.00
		2/7/2012	2578.80	2578.80	1.00
		1/19/2012	2800.80	2800.80	1.00
		12/7/2012	2656.80	2656.80	1.00
		11/16/2011	2432.40	2432.40	1.00
		10/26/2011	2115.60	2115.60	1.00
		9/11/2011	1856.40	1859.90	1.00
		8/29/2011	1828.80	1834.84	1.00
		7/7/2011	1795.20	1796.33	1.00
		6/28/2011	1593.60	1593.60	1.00
		5/2/2011	1677.60	1677.60	1.00
		4/21/2011	1852.80	1852.80	1.00

	Meter	Date	kW	kVA	PF
Ruckles	924191	4/10/2013	2497.60	2501.26	1.00
5 kVA		3/27/2013	2477.60	2481.78	1.00
		2/21/2013	2340.00	2340.00	1.00
		1/22/2013	2635.20	2635.20	1.00
		12/18/2012	2612.00	2612.00	1.00
		11/28/2012	2395.20	2395.20	1.00
		10/23/2012	2587.20	2594.98	1.00
		9/20/2012	2470.40	2488.84	0.99
		8/7/2012	3121.60	3179.95	0.98
		7/11/2012	3136.00	3193.94	0.98
		6/21/2012	2486.40	2502.57	0.99
		5/15/2012	2608.80	2633.41	0.99
		4/2/2012	2762.40	2767.41	1.00
		3/2/2012	2487.20	2487.20	1.00
		2/8/2012	2865.60	2865.60	1.00
		1/12/2012	3154.40	3154.40	1.00
		12/13/2011	3018.40	3018.40	1.00
		11/3/2011	2998.40	3008.44	1.00
		10/26/2011	2848.00	2856.00	1.00
		9/12/2011	2966.40	3018.50	0.98
		8/4/2011	3217.60	3282.52	0.98
		7/6/2011	3152.00	3210.26	0.98
		6/28/2011	2830.40	2870.01	0.99
		5/10/2011	2436.80	2449.39	0.99
		4/4/2011	2745.60	2754.34	1.00

	Meter	Date	kW	kVA	PF
Coalshute	935176	4/23/2013	1780.80	1844.67	0.97
		3/5/2013	1930.80	1989.57	0.97
		2/4/2013	2122.80	2188.06	0.97
		1/21/2013	2391.60	2447.65	0.98
		12/19/2012	2331.60	2399.69	0.97
		11/26/2012	2166.00	2230.28	0.97
		10/22/2012	1872.00	1931.96	0.97
		9/20/2012	1726.80	1836.90	0.94
		8/7/2012	1958.40	2101.86	0.93
		7/16/2012	3698.40	3782.50	0.98
		6/28/2012	2970.00	3019.12	0.98
		5/15/2012	1690.80	1834.91	0.92
		4/2/2012	1720.80	1785.53	0.96
		3/12/2012	1848.00	1917.40	0.96
		2/8/2012	2125.20	2189.81	0.97
		1/16/2012	2407.20	2466.76	0.98
		12/12/2011	2338.80	2395.56	0.98
		11/21/2011	2190.00	2254.45	0.97
		10/25/2011	3626.40	3649.28	0.99
		9/12/2011	1819.20	1977.01	0.92
		8/29/2011	1827.60	1998.57	0.91
		7/7/2011	1725.60	1892.71	0.91
		6/28/2011	1568.40	1711.54	0.92
		5/5/2011	1530.00	1601.03	0.96
		4/4/2011	1684.80	1758.91	0.96

The City of Grand Forks experienced a power factor less than 0.95 at the Coalshute delivery point (FortisBC GFT Feeder 1 Demarcation Point) from June 2011 to September 2011, in May 2012, and from August 2012 to September 2012.

1 ## City of Nelson

	Meter	Date	kW	kVA	PF
Coffee Creek	1035936	4/16/2013	3700.80	3708.65	1.00
		3/25/2012	4190.40	4196.28	1.00
		2/26/2013	3981.60	3990.26	1.00
	924185	2/18/2013	4024.80	4024.80	1.00
		1/13/2013	4760.40	4760.40	1.00
		12/9/2012	4422.00	4422.00	1.00
		11/15/2012	5085.60	5085.60	1.00
		10/25/2012	2642.40	2642.40	1.00
		9/12/2012	2031.60	2031.60	1.00
		8/20/2012	1891.20	1891.20	1.00
		7/21/2012	3003.60	3003.60	1.00
		6/6/2012	2463.60	2463.60	1.00
		5/3/2012	2518.80	2518.80	1.00
		4/2/2012	3004.80	3004.80	1.00
		3/3/2012	3453.60	3453.60	1.00
		2/27/2012	3698.40	3698.40	1.00
		1/18/2012	3967.20	3967.20	1.00
		12/22/2011	3760.80	3760.80	1.00
		11/20/2011	3702.00	3702.00	1.00
		10/26/2011	3096.00	3096.00	1.00
		9/26/2011	2090.40	2090.40	1.00
		8/1/2011	1878.00	1878.00	1.00
		7/31/2011	1915.20	1915.20	1.00
		6/17/2011	2055.60	2055.60	1.00
		5/26/2011	2462.40	2462.40	1.00
		4/2/2011	3181.20	3181.20	1.00

	Meter	Date	kW	kVA	PF
Bonnington	1035928	4/13/2013	13536.00	13604.05	0.99
		3/5/2013	16569.00	16670.41	0.99
		2/19/2013	16407.00	16729.10	0.98
	898049	2/1/2013	-	-	-
		1/1/2013	-	-	-
		12/12/2012	17289.00	17482.22	0.99
		11/1/2012	12357.00	12504.81	0.99
		10/23/2012	13563.00	13783.75	0.98
		9/1/2012	-	-	-
		8/1/2012	-	-	-
		7/1/2012	-	-	-
		6/30/2012	17694.00	18328.02	0.97
		5/1/2012	0.00	0.00	
		4/4/2012	20979.00	21106.12	0.99
		3/1/2012	-	-	-
		2/1/2012	-	-	-
		1/16/2012	21870.00	22268.51	0.98
		12/20/2011	19809.00	20143.19	0.98
		11/9/2011	252.00	252.00	1.00
		10/1/2011	-	-	-
		9/1/2011	-	-	-
		8/1/2011	-	-	-
		7/21/2011	7380.00	7502.46	0.98
		6/29/2011	12762.00	13053.88	0.98
		5/1/2011	-	-	-
		4/20/2011	16380.00	16545.03	0.99

	Meter	Date	kW	kVA	PF
Rosemont	898051	-	-	-	-
		-	-	-	-
Removed		2/28/2013	16029.00	16040.00	1.00
2/28/2013		1/14/2013	20511.00	20693.87	0.99
		12/19/2012	18711.00	18758.99	1.00
		11/27/2012	16578.00	16665.96	0.99
		10/5/2012	10116.00	10160.88	1.00
		9/5/2012	9090.00	9107.11	1.00
		8/23/2012	9018.00	9190.64	0.98
		7/19/2012	2241.00	3474.35	0.65
		6/13/2012	7065.00	7069.18	1.00
		5/3/2012	14634.00	14677.18	1.00
		4/25/2012	14940.00	14942.95	1.00
		3/5/2012	20448.00	20498.01	1.00
		2/8/2012	19053.00	19180.17	0.99
		1/18/2012	22923.00	23168.81	0.99
		12/8/2011	21024.00	21215.49	0.99
		11/16/2011	19467.00	19629.43	0.99
		10/31/2011	21474.00	21552.34	1.00
		9/26/2011	15723.00	15769.18	1.00
		8/25/2011	7632.00	8107.60	0.94
		7/7/2011	12861.00	12919.11	1.00
		6/24/2011	3996.00	4090.25	0.98
		5/4/2011	18855.00	18895.86	1.00
		4/19/2011	16551.00	16605.97	1.00

2 The City of Nelson experienced a power factor less than 0.95 at the Rosemont Substation in
3 August 2011 and in July 2012.

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
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TABLES

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.

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[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.

[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

[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 report37 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.

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[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.

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[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.

[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 Electric Utilities

PREPARED FOR

Fasken Martineau DuMoulin LLP

5 JUNE 2013

BLACK & VEATCH
Building a world of difference.

Table of Contents

Introduction and Background

Black & Veatch Canada Company (Black & Veatch) has prepared this study of Total Factor Productivity (TFP) of electric utilities 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 an electric utility in conjunction with the development of an incentive regulation plan, also known as a Performance-Based Regulation (PBR) plan for setting a utility's electric 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 an electric delivery utility the output measure is more complex because the unit of output is measured by both the number of customers served and the capacity required to deliver the kWhs of electricity 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 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 allowed 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 an electric 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 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, utility 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 maximum components at various levels of diversity at different points within the system. The measurement of output for an electric distribution and transmission utility based on a measure of throughput such as kWhs 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 the electric 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 electric distribution, costs are caused by a combination of customers, density, the age of capital, and peak load capacity served by the utility system. There is no volume/throughput-related component of costs except for very minor costs such as electric line losses and typically those costs are recovered outside of the base revenue requirements.

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 utility has more kWhs per unit of capacity than a lower load factor utility.

It is relatively easy to identify the bias from each of the above examples by illustration. If two electric utilities have identical systems in the elements of the distribution system such as conductor, substations, transformers, numbers of customers, rate base, O&M costs and so forth and the only difference is that one of the utilities has greater throughput because of higher load factor customers that utility will appear to be more productive. 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 each element of delivery capacity. Further the utilities' relative efficiency changes with changes in the weather, the economy and other factors that impact sales. By using kWhs as a measure of output, growing kWhs may overstate TFP resulting in a positive factor when TFP is actually negative. In fact, there are sound theoretical reasons to conclude that the TFP for electric utilities is not a positive number[1] 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.

It is reasonable to conclude that the labor component of TFP is likely to be a small positive number over time. 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 electric 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 more

[1] A positive value for TFP often is derived when using the throughput volume of an electric distribution utility as the measure of output.

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 infrastructure replacement 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. It is important to recognize this emphasis on investment in infrastructure replacement as part of the capital strategy for electric utilities. The electric utility data used in the AUC proceeding illustrates this point. 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 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. However, over the last 9 year period, the TFPs were significantly negative overall averaging about -1.443. The AUC averaged the results over the entire study period of 38 years and produced the positive TFP value ultimately used in the adopted Plan. There are reasons for not using the entire period because of the significant change associated with infrastructure investment occurring in the later years.

The AUC rejected the negative TFP measure produced by averaging recent data because the output measure was throughput based and the AUC attributed the negative values to poor economic conditions. The economic downturn had reduced the kWh measure of output resulting in a negative TFP because of the negative changes in output. Using the theoretically correct measure of output (customers and capacity) the change in output may still have resulted in a negative TFP because the renewal of the system caused costs to increase faster than output.

The use of a volumetric measure of output for TFP certainly creates economic bias. 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.

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, which is being undertaken by electric utilities across North America, adds cost unrelated to customer growth or additional capacity to serve non-coincident peaks (NCPs) or individual customer NCPs implying a negative TFP. In addition, TFP would also be negative for adding new electric customers who require transformers and service drop investment because these costs will be higher than the embedded average cost reflected in the cost of service for the utility which has been significantly impacted by the change in costs of these facilities. The approach to measurement of TFP should be based on the practical reality of the electric 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 TFP 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 the TFP is positive or negative. A simple example from the NERA study adopted by the AUC illustrates how the choice of inapplicable assumptions to the reality of utility operation can impact the results. By excluding general plant from the capital component of costs, the NERA 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. 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 are two overriding practical issues with the adoption of a PBR plan. The issues are 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 and that resulting rates are just and reasonable. 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 return 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 electric 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 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 electric utilities.

The Black & Veatch analysis begins with the development of the financial and operating data base for electric utilities. It was not possible to use a single data source for the electric 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[2]. As a result, the data used to estimate TFP is based on electric utilities operating in the United States. The use of electric utilities from the United States is a reasonable choice because of the common systems, technologies and operating methods. In addition the North American Electric Reliability Corporation includes electric utilities in both Canada and the United States assuring a consistent approach to reliability and employee training between the two countries. A description of the electric data base that was used as our source of data is provided below.

THE ELECTRIC UTILITY DATA BASE

The electric utility data base utilizes data for electric utilities in the U.S. as compiled in the Ventyx Velocity Suite Online data base. The Ventyx database consists of data aggregated from annual Form 1 filings submitted to the Federal Energy Regulatory Commission (FERC) as well as Form 10-K filings submitted to the Security and Exchange Commission. All information gathered from this database for purposes of this report is publicly available. Ventyx 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. Other operational data provided includes miles of transmission and distribution lines as well as substation capacity.

The data base consists of 72 electric utilities operating 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 28,372 for Fitchburg Gas & Electric Light Company to 5,278,738 for Pacific Gas & Electric Company. The companies operate in different regulatory environments including bundled and unbundled environments.

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[2] The Ontario Energy Board has begun to collect uniform data for electric distributors and that data base now has a number of years of data albeit not necessarily the exact data needed for a theoretically sound TFP study.

The sample represents all of the utilities available with a complete data base for the data examined. We have included all net plant for electric utilities 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 electric 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 electric utility data base is comprehensive and reflects an adequate sample of financial and operating characteristics. Schedule 2 presents the data for each electric utility used in Black & Veatch's estimation of TFP.

TFP ESTIMATES FOR ELECTRIC 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 study uses multiple output variables composed of the variables that actually drive costs to create a range of results to inform the selection of a TFP value. For determining the inputs and outputs, Black & Veatch has used the following measures:

Electric Outputs

- Composite Output- Weighted by Electric Customers and Substation Capacity 60%/40%
- Composite Output- Weighted by Electric Customers and Substation Capacity 40%/60%
- Output- Customers
- Output- Substation Capacity

Electric Inputs

- Change in weighted cost of capital and total expenses

Outputs

The key element of the output measures is that they actually explain the costs that are incurred by the utility to produce the output. By using several different measures, the report provides a range of TFP values allowing for the determination of a range for the TFP values. For both capacity and customers, the capital and other costs for electric delivery are explained by either capacity, customers or density. The measures used are dependent on the input of capital, labor and other factors of production and thus reflect the fundamental nature of the production function. 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 use of two composite output measures allows for a range in the impact of the customer related portion of costs. The range is based on bracketing an equal weighting of the two factors to provide some sensitivity analysis of the two factors. Since the range of results for the two weightings is nearly equal either TFP estimate based on a composite factor represents a reasonable estimate of electric TFP. The use of a single measure of output is also included in the analysis. 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.

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 electric utility. The ex-post cost of capital is measured as Operating Revenue excluding production 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 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 customer and capacity 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. 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 range of results from using various measures of output produce consistent results in the range of -.0395 to -0.0624. 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 Measures	Electric Customers/Substation Capacity weighted 40%/60%	Total Sample	-0.061515414
		Middle 80% of Sample	-0.053897196
		Middle 50% of Sample	-0.051745370
	Electric Customers/Substation Capacity weighted 60%/40%	Total Sample	-0.061990974
		Middle 80% of Sample	-0.054220518
		Middle 50% of Sample	-0.051746452
		Customer Measure	-0.062390638
		Capacity Measure	-0.039478702
		Median of Sample	-0.054410091
		Average	-0.054599484
		Range	-0.0395 to -0.0624

The measures of 80% and 50% of the sample provide an additional measure of central tendency by eliminating outliers in the data. Schedule 2 provides the supporting calculations associated with the summary results in Table 1.

CONCLUSIONS

The electric 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 electric utilities. The results represent a more comprehensive review of costs than that found in the AUC analysis and are reasonable as the foundation of an electric TFP value determination taking into account the utility specific elements of the plan.

Schedule 1: Data Sources

Data	Source
Net Utility Plant (before Nuclear)	FERC Form 1, Page 110 (Aggregated by Ventyx)
Electric Operating Revenues	FERC Form 1, Page 115 (Aggregated by Ventyx)
Electric Utility Operating Expenses	FERC Form 1, Page 115 (Aggregated by Ventyx)
Operating Revenue less Production Expense	Black & Veatch Calculation
Production Plant	FERC Form 1, Page 205 (Aggregated by Ventyx)
Transmission Plant	FERC Form 1, Page 207 (Aggregated by Ventyx)
Distribution Plant	FERC Form 1, Page 207 (Aggregated by Ventyx)
General Plant	FERC Form 1, Page 207 (Aggregated by Ventyx)
Net Plant less production	Black & Veatch Calculation
Accumulated Depreciation- Transmission	FERC Form 1, Page 219 (Aggregated by Ventyx)
Accumulated Depreciation- Distribution	FERC Form 1, Page 219 (Aggregated by Ventyx)
Accumulated Depreciation- General	FERC Form 1, Page 219 (Aggregated by Ventyx)
Accumulated Depreciation- Total Utility Plant	FERC Form 1, Page 219 (Aggregated by Ventyx)
O&M- Total Production Expense	FERC Form 1, Page 321 (Aggregated by Ventyx)
O&M- Transmission Expense	FERC Form 1, Page 321 (Aggregated by Ventyx)
O&M- Distribution Expense	FERC Form 1, Page 322 (Aggregated by Ventyx)
O&M- Customer Account Expenses	FERC Form 1, Page 322 (Aggregated by Ventyx)
O&M- Customer Service and Information Expenses	FERC Form 1, Page 323 (Aggregated by Ventyx)
Total A&G Expenses	FERC Form 1, Page 323 (Aggregated by Ventyx)
O&M- Total Sales Expenses	FERC Form 1, Page 323 (Aggregated by Ventyx)
Total O&M Expenses	FERC Form 1, Page 323 (Aggregated by Ventyx)
O&M less Production	Black & Veatch Calculation
Operating Ratio	Black & Veatch Calculation
Miles of Transmission	FERC Form 1, Page 422 (Aggregated by Ventyx)
Miles of Distribution	SEC Form 10-K Filings
Substation Capacity (MVa)	FERC Form 1, Page 426 (Aggregated by Ventyx)
Cost Change	Black & Veatch Calculation
% Cost Change	Black & Veatch Calculation
Total Electricity Customers	Black & Veatch Calculation
Density	Black & Veatch Calculation
Density Index	Black & Veatch Calculation

Schedule 2: Electric Utility Data Base

Schedule 2: Electric Utility Data Base

A	B	C	D	E	F	G	H	I
Formula:				C-O				
Utility Name	**Year**	**Electric Operating Revenues**	**Electric Utility Operating Expenses**	**Operating Revenue less Production Expense**	**Production Plant**	**Transmission Plant**	**Distribution Plant**	**General Plant**
ALLETE Inc	2007	691,834,849	623,827,122	261,860,630	837,437,544	219,585,932	401,101,558	135,778,092
ALLETE Inc	2008	677,274,728	601,098,434	314,821,355	954,802,537	222,694,613	420,379,527	139,031,179
ALLETE Inc	2009	650,260,374	577,023,107	289,822,877	1,365,552,417	357,334,876	434,015,326	146,458,315
ALLETE Inc	2010	800,268,296	707,633,183	379,346,532	1,539,820,379	393,069,000	445,110,389	151,573,993
ALLETE Inc	2011	815,724,847	697,199,779	414,640,241	1,644,346,565	407,472,889	462,789,816	163,395,931
Ameren Missouri	2007	2,798,449,849	2,355,292,601	1,663,771,736	7,099,603,930	566,825,351	3,692,927,920	484,752,738
Ameren Missouri	2008	2,754,344,038	2,363,400,623	1,590,367,557	7,228,325,412	626,929,686	3,920,569,027	522,698,418
Ameren Missouri	2009	2,706,624,010	2,291,916,013	1,660,350,369	7,316,799,549	639,495,861	4,208,426,845	546,012,766
Ameren Missouri	2010	3,031,084,760	2,521,344,728	1,864,741,708	8,164,430,439	684,608,022	4,380,591,324	495,571,761
Ameren Missouri	2011	3,226,611,565	2,701,332,833	1,933,340,550	8,062,278,941	746,874,380	4,531,168,504	510,663,766
Appalachian Power Co	2007	2,683,014,120	2,395,619,762	898,087,151	3,624,703,173	1,673,183,244	2,372,576,807	170,047,881
Appalachian Power Co	2008	3,000,501,237	2,696,212,486	986,278,381	3,707,764,769	1,752,450,105	2,499,383,288	177,041,949
Appalachian Power Co	2009	2,952,461,030	2,614,811,568	1,056,103,521	4,281,772,611	1,811,822,367	2,639,835,336	183,495,855
Appalachian Power Co	2010	3,369,702,981	3,038,229,914	1,109,313,466	4,725,466,804	1,850,468,645	2,738,285,160	185,409,001
Appalachian Power Co	2011	3,220,850,165	2,863,079,916	1,085,506,871	5,182,826,934	1,942,021,775	2,841,967,051	188,962,248
Arizona Public Service Co	2007	3,102,995,547	2,674,366,090	1,476,531,663	5,399,681,600	1,517,868,009	4,183,564,856	457,918,666
Arizona Public Service Co	2008	3,280,867,307	2,891,439,697	1,487,527,794	5,599,390,001	1,605,527,693	4,428,372,822	480,328,986
Arizona Public Service Co	2009	3,229,141,008	2,789,609,407	1,553,361,780	5,858,899,140	1,752,744,296	4,569,279,973	496,439,558
Arizona Public Service Co	2010	3,241,061,090	2,732,190,636	1,710,381,829	5,987,147,638	1,948,810,364	4,662,413,930	524,523,361
Arizona Public Service Co	2011	3,274,438,030	2,758,060,278	1,798,686,021	6,225,794,428	2,013,893,626	4,846,528,625	590,700,637
Avista Corp	2007	744,131,553	639,011,602	364,274,841	1,010,997,299	443,832,431	881,923,279	70,342,012
Avista Corp	2008	921,386,136	811,918,216	390,577,215	1,031,925,017	460,397,876	957,313,048	75,769,538
Avista Corp	2009	951,029,259	826,294,570	438,798,082	1,059,532,623	471,711,380	1,021,954,442	174,214,758
Avista Corp	2010	1,069,954,147	934,185,315	473,930,357	1,066,917,829	496,301,537	1,082,241,835	102,339,185
Avista Corp	2011	1,053,850,680	927,543,361	474,626,402	1,084,270,871	521,466,216	1,153,967,901	109,140,213
Baltimore Gas & Electric Co	2007	2,455,426,373	2,270,427,627	955,045,804	0	605,089,614	3,468,999,987	114,787,651
Baltimore Gas & Electric Co	2008	2,679,230,463	2,579,659,941	799,125,163	0	643,863,723	3,672,215,254	123,419,010
Baltimore Gas & Electric Co	2009	2,820,226,517	2,644,987,898	979,356,140	0	719,267,094	3,842,982,541	151,596,296
Baltimore Gas & Electric Co	2010	2,751,855,174	2,549,196,693	1,070,911,115	0	813,871,971	4,141,181,705	107,854,163
Baltimore Gas & Electric Co	2011	2,320,872,589	2,128,161,214	1,136,278,491	0	918,138,309	4,390,511,006	108,472,073
CenterPoint Energy Houston Electric LLC	2007	1,560,089,207	1,267,906,019	1,560,089,207	0	1,434,431,390	4,660,007,755	573,531,655
CenterPoint Energy Houston Electric LLC	2008	1,592,926,466	1,328,137,192	1,592,926,466	0	1,488,330,148	4,747,654,907	581,798,676
CenterPoint Energy Houston Electric LLC	2009	1,674,299,982	1,384,401,840	1,674,299,982	0	1,534,792,191	4,903,847,166	554,317,039
CenterPoint Energy Houston Electric LLC	2010	1,773,909,999	1,481,738,478	1,773,909,999	0	1,591,488,751	5,044,006,968	553,875,152
CenterPoint Energy Houston Electric LLC	2011	1,893,008,316	1,565,861,014	1,893,008,316	0	1,646,878,108	5,211,618,683	568,532,481
Central Hudson Gas & Electric Corp	2007	616,854,220	577,108,222	232,828,133	23,786,397	179,717,293	603,042,838	773,808
Central Hudson Gas & Electric Corp	2008	608,177,410	569,882,716	242,376,259	32,109,764	199,793,024	629,691,308	779,209
Central Hudson Gas & Electric Corp	2009	536,181,995	493,898,328	274,818,480	33,836,501	209,711,225	664,311,162	855,768
Central Hudson Gas & Electric Corp	2010	565,207,699	514,565,626	318,507,788	34,221,805	220,380,701	707,650,721	915,494
Central Hudson Gas & Electric Corp	2011	538,562,839	486,392,630	332,165,039	37,825,672	228,646,084	740,741,577	926,374
Central Vermont Public Service Corp	2007	329,118,877	311,132,343	154,258,119	148,173,369	58,869,454	289,991,879	34,079,975
Central Vermont Public Service Corp	2008	342,492,423	323,967,537	162,128,786	149,763,882	60,014,244	302,922,401	35,097,599
Central Vermont Public Service Corp	2009	341,011,607	322,115,573	169,475,930	155,165,507	72,892,665	314,988,384	37,777,059
Central Vermont Public Service Corp	2010	339,916,159	322,454,724	165,040,008	156,807,079	75,253,675	327,903,624	38,990,297
Central Vermont Public Service Corp	2011	357,979,844	341,619,807	185,755,656	161,798,499	79,812,164	341,348,054	40,752,123

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Utility Name	**Year**	**Electric Operating Revenues**	**Electric Utility Operating Expenses**	**Operating Revenue less Production Expense**	**Production Plant**	**Transmission Plant**	**Distribution Plant**	**General Plant**
Chugach Electric Association Inc	2007	257,443,919	232,192,354	101,300,640	219,757,149	258,170,796	267,651,541	53,287,829
Chugach Electric Association Inc	2008	288,292,112	260,437,951	102,192,161	226,062,481	262,911,441	272,864,256	52,860,405
Chugach Electric Association Inc	2009	290,247,308	263,411,228	101,733,160	224,905,781	265,006,699	279,988,120	52,940,928
Chugach Electric Association Inc	2010	258,325,345	233,780,760	101,665,774	227,442,076	272,582,661	284,649,584	57,857,784
Chugach Electric Association Inc	2011	283,618,369	261,490,110	101,723,910	228,695,918	274,749,121	294,123,997	53,406,727
CLECO Power LLC	2007	1,025,245,027	947,082,734	335,878,832	495,004,183	376,678,540	882,928,869	105,454,824
CLECO Power LLC	2008	1,071,579,933	978,314,439	335,895,170	498,232,657	404,382,862	920,935,190	108,395,674
CLECO Power LLC	2009	843,407,551	747,422,675	328,661,297	504,716,112	409,462,037	998,619,888	116,741,110
CLECO Power LLC	2010	1,120,329,608	903,864,497	551,333,689	1,745,534,733	438,096,336	1,047,547,321	127,398,843
CLECO Power LLC	2011	1,097,355,026	860,302,945	577,649,693	1,806,209,236	505,035,098	1,120,330,369	134,774,386
Cleveland Electric Illuminating Co (The)	2007	1,815,801,527	1,454,479,850	1,014,111,910	148,032,781	406,154,961	1,554,539,327	96,123,691
Cleveland Electric Illuminating Co (The)	2008	1,809,770,920	1,431,075,906	1,032,445,117	23,748	420,027,593	1,639,928,221	103,496,463
Cleveland Electric Illuminating Co (The)	2009	1,675,263,527	1,567,221,463	687,361,678	23,748	429,369,178	1,713,592,632	105,695,106
Cleveland Electric Illuminating Co (The)	2010	1,218,793,162	1,034,877,813	728,207,367	23,748	436,032,015	1,790,419,789	104,883,748
Cleveland Electric Illuminating Co (The)	2011	875,457,798	704,027,043	639,036,759	23,748	453,501,758	1,912,303,201	115,275,743
Commonwealth Edison Co	2007	6,114,262,487	5,644,610,943	2,522,490,422	0	2,632,872,019	11,608,706,164	1,231,375,656
Commonwealth Edison Co	2008	6,128,519,940	5,549,330,907	2,867,852,546	0	2,948,681,369	12,097,052,725	1,258,999,936
Commonwealth Edison Co	2009	5,785,431,369	5,129,499,000	3,030,351,122	0	2,960,400,859	12,661,134,802	1,303,208,996
Commonwealth Edison Co	2010	6,223,642,493	5,499,105,469	3,227,112,648	0	3,102,008,843	13,091,342,013	1,340,191,991
Commonwealth Edison Co	2011	6,116,781,278	5,355,503,610	3,295,032,914	0	3,297,198,492	13,623,869,298	1,427,319,093
Consolidated Edison Co of New York Inc	2007	7,503,890,889	6,536,774,260	4,071,253,809	364,154,461	2,445,961,963	12,141,176,736	0
Consolidated Edison Co of New York Inc	2008	7,948,135,438	6,973,241,723	4,286,141,018	414,744,876	2,648,029,406	13,307,065,654	0
Consolidated Edison Co of New York Inc	2009	7,831,256,706	6,826,033,960	4,779,276,049	436,946,245	2,753,808,202	14,263,631,629	0
Consolidated Edison Co of New York Inc	2010	8,408,954,706	7,295,902,074	5,369,974,529	452,467,265	2,994,307,715	15,177,634,092	0
Consolidated Edison Co of New York Inc	2011	8,322,914,696	7,131,521,265	5,675,368,977	471,296,069	3,378,702,043	15,920,856,653	0
Consumers Energy Co	2007	3,414,253,254	3,060,295,481	1,461,859,941	3,114,453,378	0	4,476,264,302	128,051,794
Consumers Energy Co	2008	3,578,331,774	3,167,748,810	1,717,785,914	3,144,050,958	0	4,746,751,427	141,585,214
Consumers Energy Co	2009	3,496,536,589	3,113,093,448	1,841,897,913	3,457,959,008	0	4,970,284,532	152,111,438
Consumers Energy Co	2010	3,788,272,671	3,307,289,101	2,009,471,344	3,598,319,147	0	5,247,776,917	156,053,128
Consumers Energy Co	2011	3,897,742,795	3,379,042,509	2,042,284,868	3,722,455,563	0	5,533,711,630	162,691,602
Detroit Edison Co (The)	2007	4,654,628,788	4,148,802,025	2,853,981,611	6,401,669,375	53,470,804	5,272,567,198	753,810,451
Detroit Edison Co (The)	2008	4,665,333,263	4,143,407,814	2,773,503,767	6,522,586,445	68,560,628	5,535,201,527	795,766,582
Detroit Edison Co (The)	2009	4,452,674,821	3,846,450,225	2,849,945,789	7,376,539,089	85,507,050	5,807,703,523	831,330,865
Detroit Edison Co (The)	2010	4,799,993,298	4,105,433,753	3,096,958,873	7,576,669,448	88,542,372	6,056,464,387	840,786,985
Detroit Edison Co (The)	2011	4,973,683,018	4,279,199,501	3,108,027,396	7,818,844,613	93,631,447	6,266,139,097	768,210,673
Duke Energy Carolinas	2007	5,795,462,627	4,819,404,832	3,407,944,565	11,374,041,667	2,214,167,449	7,708,603,282	579,688,933
Duke Energy Carolinas	2008	5,881,779,411	4,920,800,509	3,186,534,249	12,532,800,510	2,321,129,180	8,090,330,933	562,897,718
Duke Energy Carolinas	2009	5,485,035,962	4,549,589,304	3,094,774,585	13,778,258,103	2,413,849,351	8,412,064,048	573,518,297
Duke Energy Carolinas	2010	6,374,881,970	5,351,182,791	3,550,275,269	14,026,863,097	2,561,130,807	8,706,217,883	566,995,204
Duke Energy Carolinas	2011	6,445,319,799	5,395,083,098	3,557,004,715	15,141,295,670	2,699,011,390	8,955,111,160	709,595,991
Duke Energy Indiana	2007	2,229,308,648	1,896,772,254	1,242,126,115	4,509,512,338	889,805,677	2,019,184,385	209,445,450
Duke Energy Indiana	2008	2,480,743,972	2,169,895,957	1,269,572,586	4,997,888,934	909,264,855	2,098,209,635	221,007,390
Duke Energy Indiana	2009	2,354,692,352	2,041,805,778	1,277,971,567	5,076,001,658	958,254,583	2,189,821,683	239,574,518
Duke Energy Indiana	2010	2,517,375,577	2,133,397,234	1,384,889,330	5,106,844,745	991,533,084	2,251,530,810	258,527,678
Duke Energy Indiana	2011	2,618,717,655	2,261,429,346	1,410,688,991	5,136,791,148	1,038,451,517	2,296,422,410	270,510,384

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Utility Name	**Year**	**Electric Operating Revenues**	**Electric Utility Operating Expenses**	**Operating Revenue less Production Expense**	**Production Plant**	**Transmission Plant**	**Distribution Plant**	**General Plant**
Duke Energy Ohio	2007	2,829,859,980	2,532,660,062	1,321,198,094	4,781,358,991	614,918,436	1,627,976,822	35,900,541
Duke Energy Ohio	2008	2,526,195,598	2,274,595,199	1,245,364,049	4,781,031,416	643,942,285	1,693,326,884	37,844,663
Duke Energy Ohio	2009	2,474,517,011	2,174,592,048	1,280,307,787	5,332,820,417	667,047,537	1,765,233,093	64,537,266
Duke Energy Ohio	2010	2,393,860,776	2,139,767,179	1,270,539,121	5,047,479,619	671,111,058	1,844,361,344	104,375,566
Duke Energy Ohio	2011	1,894,134,836	1,674,452,678	899,404,630	3,379,461,653	608,828,977	1,925,591,877	90,270,138
Empire District Electric Co (The)	2007	425,719,536	366,930,067	212,772,183	550,242,874	191,595,311	596,340,979	58,057,107
Empire District Electric Co (The)	2008	446,465,603	382,053,388	218,757,738	589,117,019	197,450,159	625,918,270	59,746,634
Empire District Electric Co (The)	2009	433,133,378	365,583,164	225,336,934	690,768,270	203,435,386	651,657,072	60,805,818
Empire District Electric Co (The)	2010	482,910,456	413,103,364	255,152,305	1,015,039,989	220,514,385	682,174,826	62,084,946
Empire District Electric Co (The)	2011	522,506,506	436,591,128	289,357,798	1,023,153,639	232,390,509	719,731,240	64,586,390
Fitchburg Gas & Electric Light Co	2007	67,233,987	62,290,176	23,506,757	0	9,035,750	78,414,711	1,854,524
Fitchburg Gas & Electric Light Co	2008	66,433,660	62,141,789	26,403,247	0	9,005,724	81,597,508	1,840,125
Fitchburg Gas & Electric Light Co	2009	63,426,474	60,068,484	28,278,210	0	9,046,466	91,438,122	1,741,855
Fitchburg Gas & Electric Light Co	2010	62,998,861	58,416,950	30,409,468	0	9,132,164	96,459,154	2,211,841
Fitchburg Gas & Electric Light Co	2011	59,369,891	53,958,038	32,007,050	0	9,343,602	98,502,604	2,294,836
Florida Power & Light Co	2007	11,620,010,684	10,512,601,488	4,305,837,410	11,387,521,453	3,134,656,369	9,624,305,623	873,094,736
Florida Power & Light Co	2008	11,646,790,586	10,544,415,620	4,281,623,330	11,697,996,904	3,347,160,244	10,073,173,290	844,530,735
Florida Power & Light Co	2009	11,487,760,529	10,384,237,705	4,674,812,886	13,231,801,481	3,643,381,217	10,461,084,532	841,429,682
Florida Power & Light Co	2010	10,482,018,931	9,213,442,382	4,845,017,164	13,927,136,163	3,661,902,645	10,786,864,022	850,921,274
Florida Power & Light Co	2011	10,609,210,465	9,221,981,132	4,976,598,053	15,207,256,209	3,810,648,253	11,207,417,125	783,173,256
Idaho Power Co	2007	875,401,235	753,554,363	486,688,901	1,639,709,759	684,399,525	1,175,428,671	226,463,847
Idaho Power Co	2008	956,075,564	802,542,202	535,879,241	1,736,670,375	742,870,924	1,254,048,343	242,163,992
Idaho Power Co	2009	1,045,996,381	870,694,192	580,466,313	1,758,813,424	768,259,966	1,331,064,592	246,159,637
Idaho Power Co	2010	1,033,052,120	842,631,754	592,473,300	1,792,305,027	855,201,745	1,377,239,406	251,607,703
Idaho Power Co	2011	1,021,585,142	814,535,732	593,311,590	1,832,286,836	871,783,789	1,434,925,273	270,837,132
Indiana Michigan Power Co	2007	2,006,310,907	1,781,190,943	755,999,848	3,506,421,153	1,078,331,817	1,181,722,904	82,960,497
Indiana Michigan Power Co	2008	2,138,185,596	1,905,793,011	719,940,507	3,510,871,880	1,115,559,969	1,282,807,855	90,950,125
Indiana Michigan Power Co	2009	2,085,781,133	1,778,386,132	819,269,571	3,610,392,143	1,153,823,876	1,360,318,756	97,685,547
Indiana Michigan Power Co	2010	2,157,506,760	1,947,485,765	752,100,383	3,747,654,776	1,188,467,115	1,410,942,845	100,340,285
Indiana Michigan Power Co	2011	2,128,984,087	1,898,612,472	762,906,023	3,904,440,602	1,224,587,801	1,481,455,103	103,522,722
Indianapolis Power & Light	2007	1,051,865,454	841,111,372	654,783,518	2,340,243,317	212,956,114	1,090,395,002	147,124,082
Indianapolis Power & Light	2008	1,078,563,309	898,741,010	634,749,982	2,370,098,105	208,164,173	1,129,738,794	152,082,507
Indianapolis Power & Light	2009	1,067,996,891	897,949,037	621,275,715	2,415,431,106	209,064,350	1,160,026,843	172,349,832
Indianapolis Power & Light	2010	1,144,797,510	973,236,330	625,147,948	2,438,242,327	239,454,160	1,184,433,645	163,240,665
Indianapolis Power & Light	2011	1,171,921,385	1,019,639,888	602,294,512	2,605,636,316	238,762,106	1,219,070,384	170,739,992
Interstate Power & Light Co	2007	1,338,740,322	1,130,470,414	666,941,699	1,582,061,774	0	1,617,707,560	161,493,228
Interstate Power & Light Co	2008	1,300,201,458	1,133,094,188	632,945,312	1,581,076,342	0	1,714,281,774	165,293,599
Interstate Power & Light Co	2009	1,331,849,293	1,176,129,907	661,542,182	2,255,119,674	0	1,812,225,281	179,450,385
Interstate Power & Light Co	2010	1,481,461,518	1,274,927,487	816,407,028	2,385,561,005	0	1,923,678,158	182,400,284
Interstate Power & Light Co	2011	1,426,650,071	1,225,815,803	769,316,658	2,390,092,531	0	2,044,402,258	178,620,228
Jersey Central Power & Light Co	2007	3,185,507,703	2,933,311,743	1,219,081,328	125,100,156	802,464,302	2,897,691,563	295,239,809
Jersey Central Power & Light Co	2008	3,421,892,733	3,155,240,575	1,210,893,891	125,114,330	837,160,757	2,990,016,898	294,528,479
Jersey Central Power & Light Co	2009	2,947,559,789	2,700,802,827	1,161,768,799	125,528,615	870,406,530	3,110,751,432	292,193,107
Jersey Central Power & Light Co	2010	2,973,585,527	2,678,869,776	1,232,959,768	88,204,950	886,986,636	3,230,580,265	289,873,216
Jersey Central Power & Light Co	2011	2,437,144,347	2,188,861,082	1,051,091,685	89,723,715	955,700,933	3,468,185,879	281,035,027

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Formula:				C-O				
Utility Name	Year	Electric Operating Revenues	Electric Utility Operating Expenses	Operating Revenue less Production Expense	Production Plant	Transmission Plant	Distribution Plant	General Plant
Kentucky Power Co	2007	606,969,066	542,657,414	203,348,945	475,852,636	402,228,844	502,486,382	31,554,528
Kentucky Power Co	2008	692,226,601	631,386,025	192,918,249	527,219,064	431,804,417	528,711,039	33,659,644
Kentucky Power Co	2009	653,299,864	595,493,098	195,443,574	540,095,917	438,744,866	568,761,740	33,960,860
Kentucky Power Co	2010	709,212,128	636,843,396	230,574,475	546,127,449	444,272,440	589,978,075	34,037,318
Kentucky Power Co	2011	741,001,224	662,901,250	255,908,298	546,756,491	456,521,424	612,204,396	34,146,492
Kingsport Power Co	2007	100,127,919	94,572,519	24,284,586	0	17,262,240	92,829,367	1,980,593
Kingsport Power Co	2008	114,620,439	110,835,801	22,390,289	0	17,421,868	96,617,889	2,249,505
Kingsport Power Co	2009	144,908,008	144,849,147	21,360,860	0	17,532,350	100,741,783	2,408,511
Kingsport Power Co	2010	154,691,289	146,205,019	30,857,258	0	19,006,058	104,884,065	2,388,946
Kingsport Power Co	2011	151,493,306	147,067,940	24,755,597	0	20,264,445	109,954,977	2,451,681
Madison Gas & Electric Co	2007	346,200,485	300,617,714	176,638,929	278,579,087	2,448,899	364,652,739	11,030,353
Madison Gas & Electric Co	2008	367,437,633	324,306,893	190,054,391	340,903,796	2,448,899	380,848,212	10,865,548
Madison Gas & Electric Co	2009	340,798,371	300,360,405	187,847,989	344,788,939	0	410,230,108	10,861,822
Madison Gas & Electric Co	2010	367,925,847	314,848,413	221,695,329	353,484,521	0	433,940,470	11,291,710
Madison Gas & Electric Co	2011	381,082,812	319,901,321	234,354,948	359,759,605	0	469,949,381	11,777,855
MDU Resources Group Inc	2007	189,941,801	167,058,666	100,097,131	316,215,606	129,802,743	203,335,272	19,380,379
MDU Resources Group Inc	2008	203,439,609	176,374,567	110,097,684	354,845,887	139,537,133	216,311,197	20,228,267
MDU Resources Group Inc	2009	193,582,621	165,424,721	108,476,200	380,352,380	143,199,007	227,061,799	20,768,011
MDU Resources Group Inc	2010	209,180,834	171,829,075	124,755,675	522,946,186	151,750,059	237,513,020	21,863,660
MDU Resources Group Inc	2011	223,201,621	181,146,038	135,112,575	526,554,285	166,501,719	250,067,599	21,914,789
Metropolitan Edison Co	2007	1,510,843,430	1,380,707,023	715,401,274	97,432,251	283,900,721	1,387,375,967	181,172,161
Metropolitan Edison Co	2008	1,653,265,374	1,532,271,552	752,404,693	97,432,251	305,482,055	1,455,145,802	181,989,742
Metropolitan Edison Co	2009	1,689,266,073	1,591,692,662	784,247,078	95,321,154	319,155,815	1,540,426,440	180,062,067
Metropolitan Edison Co	2010	1,818,864,856	1,712,453,215	859,832,545	95,321,154	326,052,024	1,613,143,894	183,926,823
Metropolitan Edison Co	2011	1,212,620,896	1,090,449,978	585,466,656	95,321,154	353,357,004	1,801,918,805	187,103,435
Monongahela Power Co	2007	932,497,266	880,171,336	329,864,328	1,141,681,340	296,625,839	1,007,459,250	77,916,468
Monongahela Power Co	2008	856,041,526	808,070,905	304,603,647	1,183,466,166	307,290,249	1,054,155,542	78,689,503
Monongahela Power Co	2009	883,439,743	829,020,296	328,689,675	1,692,178,895	320,455,678	1,116,415,555	76,739,854
Monongahela Power Co	2010	1,032,254,572	944,499,610	378,574,440	1,719,209,126	332,326,765	1,167,593,340	81,102,779
Monongahela Power Co	2011	1,245,230,707	1,214,545,957	499,199,280	1,438,467,527	355,424,358	1,227,836,576	90,493,553
Northern States Power Co (Minnesota)	2007	3,619,988,045	3,222,986,516	1,571,310,825	4,476,800,295	1,435,314,360	2,735,476,393	176,553,286
Northern States Power Co (Minnesota)	2008	3,673,215,479	3,270,051,589	1,617,188,467	4,853,235,921	1,593,641,924	2,831,273,473	197,582,319
Northern States Power Co (Minnesota)	2009	3,467,568,383	3,057,365,458	1,649,601,322	4,842,806,813	1,711,985,627	2,928,723,088	217,578,517
Northern States Power Co (Minnesota)	2010	3,742,200,745	3,346,037,790	1,704,561,517	5,466,796,190	1,823,114,974	3,031,579,538	264,928,184
Northern States Power Co (Minnesota)	2011	3,793,733,453	3,323,290,931	1,833,315,878	6,490,298,740	1,979,213,495	3,168,661,143	277,440,548
Northern States Power Co (Wisconsin)	2007	630,870,817	579,828,726	239,346,534	380,905,707	360,894,681	549,964,021	36,529,983
Northern States Power Co (Wisconsin)	2008	664,239,968	604,104,367	258,468,694	402,997,316	396,952,826	574,338,222	44,781,490
Northern States Power Co (Wisconsin)	2009	670,942,464	610,045,719	273,574,697	414,130,679	407,746,197	596,953,767	52,286,971
Northern States Power Co (Wisconsin)	2010	707,073,655	649,851,068	286,234,640	413,544,420	466,189,443	627,186,428	62,639,814
Northern States Power Co (Wisconsin)	2011	753,946,609	685,955,054	312,028,238	423,472,949	504,463,678	664,927,989	69,805,620
NorthWestern Corp	2007	839,548,471	759,534,947	381,441,569	222,965,283	549,338,941	979,362,505	77,402,556
NorthWestern Corp	2008	936,046,225	858,415,353	389,249,433	230,569,352	563,698,611	1,024,831,522	81,276,225
NorthWestern Corp	2009	794,543,777	679,350,327	406,568,123	238,163,869	575,820,421	1,062,016,264	86,147,175
NorthWestern Corp	2010	807,406,416	699,088,002	413,384,397	416,290,083	609,927,119	1,098,192,018	90,626,041
NorthWestern Corp	2011	808,318,183	682,361,052	449,375,959	420,280,691	645,783,668	1,140,681,148	95,973,765

Schedule 2: Electric Utility Data Base

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Formula:				C-O				
Utility Name	Year	Electric Operating Revenues	Electric Utility Operating Expenses	Operating Revenue less Production Expense	Production Plant	Transmission Plant	Distribution Plant	General Plant
NSTAR Electric Co	2007	2,782,770,383	2,476,581,702	1,368,801,852	0	959,406,158	3,441,383,125	164,837,916
NSTAR Electric Co	2008	2,902,381,651	2,591,621,149	1,442,276,556	0	1,119,636,558	3,599,972,389	176,148,709
NSTAR Electric Co	2009	2,710,212,986	2,397,464,332	1,493,229,746	0	1,234,002,802	3,781,885,589	179,657,600
NSTAR Electric Co	2010	2,642,359,177	2,325,582,014	1,587,371,139	0	1,293,294,035	3,923,484,823	184,521,250
NSTAR Electric Co	2011	2,633,057,952	2,312,271,524	1,656,657,093	0	1,386,906,403	4,085,712,957	181,870,260
Ohio Edison Co	2007	2,202,993,611	2,013,167,089	910,883,853	142,801,677	262,867,811	1,810,869,785	120,646,289
Ohio Edison Co	2008	2,329,376,518	2,110,366,040	995,080,509	106,135,767	271,265,622	1,902,597,311	139,263,885
Ohio Edison Co	2009	2,249,080,880	2,089,493,426	749,291,629	120,537,319	272,432,785	1,994,495,337	139,223,098
Ohio Edison Co	2010	1,577,485,623	1,377,583,492	701,950,942	108,096,641	273,026,948	2,083,543,943	137,525,068
Ohio Edison Co	2011	1,395,495,932	1,228,491,029	754,985,731	113,022,254	284,650,792	2,221,918,752	152,802,874
Ohio Power Co	2007	4,947,396,946	4,242,773,586	2,335,614,453	7,068,487,338	1,573,677,093	2,945,592,662	214,785,414
Ohio Power Co	2008	5,416,432,242	4,726,551,328	2,291,282,630	7,722,113,786	1,679,909,619	3,095,333,768	246,017,424
Ohio Power Co	2009	5,069,817,215	4,287,468,257	2,481,091,832	9,431,497,817	1,784,235,533	3,309,752,567	236,964,263
Ohio Power Co	2010	5,490,192,592	4,723,337,339	2,650,474,844	9,630,361,630	1,890,986,946	3,417,861,901	240,379,485
Ohio Power Co	2011	5,455,769,264	4,786,996,609	2,451,408,506	9,554,099,448	1,942,327,221	3,540,883,305	230,824,790
Oklahoma Gas & Electric Co	2007	1,902,651,057	1,681,952,942	705,648,698	2,198,147,288	723,159,334	2,305,070,699	196,095,362
Oklahoma Gas & Electric Co	2008	2,036,213,558	1,808,843,038	726,425,572	2,577,921,655	789,771,070	2,505,158,061	202,912,932
Oklahoma Gas & Electric Co	2009	1,841,267,950	1,559,525,640	839,942,938	2,880,589,934	860,448,242	2,641,328,297	215,908,052
Oklahoma Gas & Electric Co	2010	2,210,106,216	1,896,996,466	1,001,917,848	2,879,190,780	1,130,573,038	2,786,122,370	225,823,555
Oklahoma Gas & Electric Co	2011	2,328,466,158	1,962,387,573	1,117,161,223	3,336,015,647	1,244,451,853	2,937,070,364	267,552,258
Oncor Electric Delivery	2007	2,355,678,268	1,772,414,044	2,355,678,268	0	3,387,713,389	8,036,189,657	265,554,669
Oncor Electric Delivery	2008	2,440,699,756	1,831,812,423	2,440,699,756	0	3,626,717,486	8,426,865,847	332,867,586
Oncor Electric Delivery	2009	2,544,597,061	1,978,219,743	2,544,597,061	0	3,920,099,220	8,760,133,828	353,453,516
Oncor Electric Delivery	2010	2,761,936,048	2,145,707,885	2,761,936,048	0	4,372,184,776	9,112,034,455	390,038,548
Oncor Electric Delivery	2011	2,968,423,216	2,306,804,185	2,968,423,216	0	4,918,677,292	9,485,662,023	444,613,841
Orange & Rockland Utilities Inc	2007	484,436,146	443,638,487	210,000,128	0	145,058,679	531,867,870	31,515,920
Orange & Rockland Utilities Inc	2008	519,110,808	480,886,596	219,055,691	0	159,191,762	567,110,036	33,617,096
Orange & Rockland Utilities Inc	2009	444,019,181	404,810,800	242,229,549	0	161,774,191	596,922,276	38,945,964
Orange & Rockland Utilities Inc	2010	479,603,238	440,346,072	264,802,200	0	162,558,503	625,560,621	42,667,369
Orange & Rockland Utilities Inc	2011	456,689,880	414,399,211	280,934,954	0	209,992,095	665,668,544	45,565,195
Pacific Gas & Electric Co	2007	9,568,124,782	8,347,334,466	5,665,989,994	8,956,064,412	4,744,488,146	16,012,064,990	564,606,743
Pacific Gas & Electric Co	2008	10,847,475,461	9,491,918,765	5,902,193,040	9,318,520,422	5,014,453,338	16,956,032,722	587,870,660
Pacific Gas & Electric Co	2009	10,307,526,947	8,877,173,728	6,095,483,528	9,957,311,304	5,646,695,540	18,016,628,180	562,484,484
Pacific Gas & Electric Co	2010	10,706,164,801	9,136,850,736	6,356,883,594	11,046,511,374	6,294,234,824	18,960,987,824	622,804,203
Pacific Gas & Electric Co	2011	11,669,946,697	10,329,870,288	7,131,793,590	11,345,481,000	6,694,958,718	20,203,840,412	578,948,736
PECO Energy Co	2007	4,768,183,487	4,130,468,336	2,658,011,761	0	950,451,587	3,941,010,931	59,357,763
PECO Energy Co	2008	4,745,436,065	4,260,588,352	2,610,526,412	0	986,052,233	4,135,239,648	51,981,780
PECO Energy Co	2009	4,553,027,351	4,141,373,819	2,522,103,978	0	1,029,161,072	4,322,385,718	56,477,263
PECO Energy Co	2010	4,834,125,314	4,457,558,668	2,721,438,362	0	1,054,609,515	4,489,936,826	90,352,399
PECO Energy Co	2011	3,106,752,854	2,714,961,071	1,663,241,583	0	1,184,115,819	4,723,425,790	156,864,072
Pennsylvania Electric Co	2007	1,402,334,793	1,260,069,051	611,438,710	48,716,124	338,200,328	1,679,233,013	131,008,807
Pennsylvania Electric Co	2008	1,513,870,869	1,360,541,124	637,864,824	48,716,124	341,441,171	1,768,168,251	141,497,679
Pennsylvania Electric Co	2009	1,449,185,511	1,337,532,800	562,577,644	47,660,577	361,028,263	1,853,970,260	142,087,119
Pennsylvania Electric Co	2010	1,540,121,238	1,414,541,352	532,022,121	47,660,577	378,577,958	1,936,780,860	141,261,577
Pennsylvania Electric Co	2011	1,081,260,654	945,066,616	540,475,111	47,660,577	441,821,881	2,153,469,961	135,823,052

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Formula:				C-O				
Utility Name	Year	Electric Operating Revenues	Electric Utility Operating Expenses	Operating Revenue less Production Expense	Production Plant	Transmission Plant	Distribution Plant	General Plant
Pennsylvania Power Co	2007	289,415,521	271,874,051	88,776,015	0	20,840,748	353,799,149	10,415,947
Pennsylvania Power Co	2008	277,176,939	255,322,661	94,610,600	0	21,328,520	382,257,799	16,074,760
Pennsylvania Power Co	2009	265,397,958	235,303,834	102,363,083	0	21,311,732	405,739,500	16,263,565
Pennsylvania Power Co	2010	259,372,897	229,858,985	114,730,661	0	21,392,006	425,125,856	16,166,506
Pennsylvania Power Co	2011	238,081,941	217,109,054	125,439,822	0	21,951,008	463,891,696	16,505,670
Potomac Edison Co (The)	2007	893,987,027	857,956,128	248,962,768	0	344,043,161	1,348,950,713	75,153,231
Potomac Edison Co (The)	2008	950,486,891	949,625,774	242,260,617	0	354,610,606	1,432,579,439	79,872,366
Potomac Edison Co (The)	2009	1,058,180,121	988,885,049	274,316,651	0	378,405,557	1,489,477,429	78,666,606
Potomac Edison Co (The)	2010	981,229,972	915,211,216	254,329,102	0	380,598,863	1,209,392,444	69,894,585
Potomac Edison Co (The)	2011	865,405,251	806,742,225	266,675,559	0	389,622,838	1,262,686,769	68,355,134
PPL Electric Utilities Corp	2007	3,558,588,531	3,294,320,331	1,542,476,536	0	1,081,704,788	3,414,497,034	432,546,207
PPL Electric Utilities Corp	2008	3,553,697,495	3,281,014,641	1,567,345,568	0	1,150,044,754	3,538,289,927	470,510,793
PPL Electric Utilities Corp	2009	3,430,851,117	3,182,200,057	1,516,728,248	0	1,181,764,806	3,660,881,066	497,780,433
PPL Electric Utilities Corp	2010	2,502,266,196	2,286,970,127	1,110,341,420	0	1,259,407,293	3,834,167,137	529,672,812
PPL Electric Utilities Corp	2011	1,957,973,936	1,679,970,578	1,194,824,735	0	1,347,452,520	4,053,958,972	555,962,346
Progress Energy Carolinas	2007	4,393,270,862	3,719,552,549	2,176,146,098	8,933,012,125	1,359,257,137	4,139,294,784	476,059,347
Progress Energy Carolinas	2008	4,435,219,204	3,765,687,805	2,208,023,380	9,215,513,434	1,455,381,332	4,322,198,703	479,190,990
Progress Energy Carolinas	2009	4,632,195,052	3,977,401,457	2,157,388,094	9,544,822,138	1,534,095,864	4,491,522,891	498,741,217
Progress Energy Carolinas	2010	4,921,811,016	4,216,711,316	2,309,229,484	9,910,820,378	1,624,845,579	4,679,284,825	510,479,426
Progress Energy Carolinas	2011	4,528,783,200	3,891,766,525	2,229,433,774	10,476,367,658	1,823,871,897	4,879,168,944	522,090,418
Progress Energy Florida	2007	4,692,523,332	4,253,993,897	1,882,669,783	4,409,093,860	1,317,323,608	3,534,697,873	379,209,924
Progress Energy Florida	2008	4,730,890,488	4,230,952,457	1,569,868,005	4,491,652,159	1,508,154,773	3,707,979,640	362,025,813
Progress Energy Florida	2009	5,250,621,713	4,658,903,442	2,292,334,231	6,091,086,859	1,733,677,133	3,885,359,783	355,845,965
Progress Energy Florida	2010	5,253,982,000	4,572,934,647	2,137,064,490	6,519,062,647	1,898,551,268	4,017,601,528	352,569,462
Progress Energy Florida	2011	4,369,042,300	3,842,477,130	1,607,885,689	6,579,819,626	2,030,853,796	4,146,253,365	328,836,479
Public Service Co of Colorado	2007	2,767,415,093	2,428,160,318	1,040,225,456	2,408,764,328	1,010,998,278	3,061,714,187	78,877,333
Public Service Co of Colorado	2008	3,070,533,558	2,740,220,568	1,035,896,159	2,603,002,206	1,094,887,860	3,233,264,792	89,511,792
Public Service Co of Colorado	2009	2,721,064,550	2,368,646,925	1,132,581,930	2,866,389,418	1,228,320,380	3,346,225,604	129,467,213
Public Service Co of Colorado	2010	3,132,780,856	2,701,214,654	1,383,187,918	4,391,630,237	1,366,456,909	3,477,848,131	145,799,243
Public Service Co of Colorado	2011	3,182,262,326	2,699,241,788	1,507,010,693	4,401,010,587	1,488,459,371	3,631,063,221	144,447,279
Public Service Co of New Mexico	2007	1,163,511,302	1,103,261,850	319,816,619	1,438,222,520	454,276,520	986,460,866	92,175,920
Public Service Co of New Mexico	2008	1,185,096,703	1,109,648,179	365,149,162	1,736,931,071	480,549,772	1,033,415,955	96,163,530
Public Service Co of New Mexico	2009	968,029,501	889,593,088	395,164,324	1,744,571,097	494,386,148	1,067,461,869	135,213,264
Public Service Co of New Mexico	2010	1,020,727,233	912,155,634	465,154,767	1,811,047,436	557,220,204	1,097,952,663	121,797,446
Public Service Co of New Mexico	2011	1,053,074,411	932,408,111	497,693,890	1,937,850,765	588,272,716	1,129,913,786	122,393,868
Public Service Co of Oklahoma	2007	1,394,715,863	1,366,830,482	414,582,301	1,110,657,255	569,745,856	1,337,038,338	165,117,111
Public Service Co of Oklahoma	2008	1,643,041,965	1,500,539,865	443,624,640	1,266,356,545	622,664,895	1,468,481,222	163,150,485
Public Service Co of Oklahoma	2009	1,120,475,188	989,431,649	534,817,789	1,298,027,706	617,290,679	1,596,276,226	146,119,892
Public Service Co of Oklahoma	2010	1,269,209,150	1,130,763,265	573,326,938	1,326,896,725	663,993,516	1,686,391,124	146,432,730
Public Service Co of Oklahoma	2011	1,362,825,453	1,184,451,252	612,244,444	1,314,330,678	692,643,975	1,762,031,440	142,466,387
Public Service Electric & Gas Co	2007	5,071,611,653	4,679,034,567	1,727,927,763	0	1,562,390,647	5,294,236,352	224,153,314
Public Service Electric & Gas Co	2008	5,511,424,364	5,145,118,193	1,736,486,073	0	1,655,309,715	5,567,333,069	255,996,918
Public Service Electric & Gas Co	2009	5,100,284,290	4,752,139,869	1,805,083,657	12,513,163	1,890,809,863	5,804,214,973	234,785,573
Public Service Electric & Gas Co	2010	4,974,789,692	4,579,613,633	1,902,167,343	174,185,839	2,148,372,406	6,208,006,802	214,958,949
Public Service Electric & Gas Co	2011	4,731,963,234	4,210,717,217	2,056,314,672	345,239,585	2,441,396,590	6,522,652,726	214,460,233

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A	B	C	D	E	F	G	H	I
Formula:				**C-O**				
Utility Name	**Year**	**Electric Operating Revenues**	**Electric Utility Operating Expenses**	**Operating Revenue less Production Expense**	**Production Plant**	**Transmission Plant**	**Distribution Plant**	**General Plant**
San Diego Gas & Electric Co	2007	2,239,776,792	1,917,082,038	1,418,779,215	1,872,234,850	1,373,032,852	3,831,213,273	152,081,614
San Diego Gas & Electric Co	2008	2,613,997,462	2,232,711,604	1,518,993,947	1,928,770,674	1,521,793,576	4,011,579,342	161,082,698
San Diego Gas & Electric Co	2009	2,508,327,327	2,130,739,153	1,576,946,425	2,023,130,678	1,649,721,948	4,243,039,156	171,081,428
San Diego Gas & Electric Co	2010	2,658,490,381	2,259,861,493	1,669,813,968	2,122,223,816	1,728,103,312	4,503,871,028	187,204,624
San Diego Gas & Electric Co	2011	3,395,043,131	2,985,886,650	1,933,246,154	2,531,551,181	1,861,548,032	4,709,168,082	203,501,252
South Carolina Electric & Gas Co	2007	1,961,657,591	1,631,226,545	1,050,194,007	3,933,937,723	696,026,663	2,160,700,687	171,893,681
South Carolina Electric & Gas Co	2008	2,248,019,885	1,884,356,512	1,131,932,027	4,153,973,707	746,471,076	2,321,878,869	180,884,593
South Carolina Electric & Gas Co	2009	2,148,904,316	1,787,665,136	1,102,322,386	4,197,322,863	806,674,940	2,468,518,839	218,106,731
South Carolina Electric & Gas Co	2010	2,366,975,197	1,968,932,301	1,170,618,431	4,548,134,452	866,475,874	2,571,137,816	227,954,795
South Carolina Electric & Gas Co	2011	2,432,190,193	1,988,488,311	1,243,784,494	4,547,070,524	910,915,254	2,682,725,492	257,299,553
Southern California Edison Co	2007	10,217,524,856	9,213,671,820	5,296,026,521	7,982,830,784	4,655,424,552	12,146,469,548	1,544,609,504
Southern California Edison Co	2008	10,261,745,645	9,201,167,736	3,770,966,920	8,096,716,871	4,757,870,321	12,750,953,116	1,550,436,365
Southern California Edison Co	2009	9,942,797,532	8,693,151,403	6,293,150,523	8,849,593,432	5,447,414,246	13,744,722,675	1,640,191,465
Southern California Edison Co	2010	10,392,073,023	9,106,419,900	6,505,477,979	9,431,851,178	5,811,336,256	14,877,581,182	1,804,660,920
Southern California Edison Co	2011	10,614,760,997	9,167,487,388	5,825,152,799	9,996,062,884	6,109,386,834	15,938,199,116	2,123,098,622
Southern Indiana Gas & Electric Co	2007	488,000,653	408,610,248	249,963,220	1,158,224,321	238,336,836	390,230,401	23,526,951
Southern Indiana Gas & Electric Co	2008	524,375,537	440,900,838	265,622,058	1,181,051,793	249,936,274	423,288,828	24,056,707
Southern Indiana Gas & Electric Co	2009	528,673,984	448,147,907	273,459,474	1,318,082,771	284,683,997	478,397,893	25,934,766
Southern Indiana Gas & Electric Co	2010	608,185,246	512,602,411	311,675,839	1,368,669,964	359,761,805	496,406,852	27,790,086
Southern Indiana Gas & Electric Co	2011	636,114,606	535,071,575	322,703,810	1,394,851,312	365,419,891	520,346,687	29,040,310
Southwestern Electric Power Co	2007	1,434,476,664	1,320,667,526	498,178,605	1,728,928,279	737,975,571	1,312,685,630	279,598,297
Southwestern Electric Power Co	2008	1,583,709,485	1,435,846,253	558,560,967	1,794,177,313	786,731,548	1,400,516,409	291,764,895
Southwestern Electric Power Co	2009	1,301,005,940	1,172,849,992	534,087,336	1,823,449,844	869,565,533	1,446,712,574	292,597,087
Southwestern Electric Power Co	2010	1,517,191,200	1,339,899,586	643,723,921	2,288,451,984	943,219,585	1,610,282,728	302,020,696
Southwestern Electric Power Co	2011	1,660,041,190	1,443,858,072	710,737,310	2,312,167,355	988,029,328	1,674,918,482	308,449,476
Southwestern Public Service Co	2007	1,677,595,170	1,593,192,139	402,332,463	1,617,862,067	763,299,048	839,977,554	206,554,970
Southwestern Public Service Co	2008	2,011,645,228	1,923,283,320	419,962,079	1,653,320,643	823,579,848	872,486,930	193,106,206
Southwestern Public Service Co	2009	1,474,903,769	1,341,345,879	505,530,511	1,682,740,141	928,838,783	904,693,448	202,233,373
Southwestern Public Service Co	2010	1,623,318,460	1,487,722,879	546,532,943	1,723,823,486	973,239,271	842,210,362	223,314,169
Southwestern Public Service Co	2011	1,719,370,563	1,569,507,732	590,877,969	1,822,154,215	1,110,491,356	892,614,721	244,300,215
Tampa Electric Co	2007	2,150,646,110	1,901,123,629	895,810,121	2,997,549,161	443,180,905	1,629,079,838	167,028,064
Tampa Electric Co	2008	2,095,838,564	1,856,375,532	732,799,316	3,133,548,067	471,928,677	1,714,120,538	169,768,080
Tampa Electric Co	2009	2,267,930,058	2,002,579,108	1,106,368,258	3,540,416,676	531,714,712	1,776,258,095	177,841,510
Tampa Electric Co	2010	2,210,060,387	1,882,062,497	1,130,071,352	3,732,042,573	561,628,697	1,833,777,784	176,274,046
Tampa Electric Co	2011	2,019,640,877	1,697,247,068	1,024,416,404	3,804,979,864	598,112,281	1,884,697,093	176,154,105
Toledo Edison Co (The)	2007	963,944,676	853,604,856	449,640,033	115,298,956	33,237,559	702,180,785	67,694,286
Toledo Edison Co (The)	2008	895,504,911	808,203,639	427,158,424	832,812	33,425,041	744,177,555	76,184,849
Toledo Edison Co (The)	2009	833,908,176	785,420,377	255,610,908	832,812	33,730,398	782,097,441	77,859,827
Toledo Edison Co (The)	2010	516,696,578	446,686,392	224,889,045	0	35,862,767	813,394,664	77,264,947
Toledo Edison Co (The)	2011	476,970,645	412,327,239	253,555,830	0	36,217,591	856,363,158	82,102,972
Tucson Electric Power Co	2007	1,099,837,491	1,002,871,897	401,006,383	1,339,378,577	580,139,762	984,656,894	162,487,211
Tucson Electric Power Co	2008	1,108,088,887	1,064,496,126	323,563,733	1,394,590,216	659,711,097	1,044,213,802	173,564,151
Tucson Electric Power Co	2009	1,117,315,604	1,005,842,402	472,252,374	1,524,268,694	681,858,500	1,110,378,359	177,731,530
Tucson Electric Power Co	2010	1,159,393,794	1,015,974,458	500,706,881	1,727,883,541	705,110,816	1,168,444,827	186,585,199
Tucson Electric Power Co	2011	1,171,179,710	1,037,982,328	494,737,526	1,813,596,354	765,654,160	1,233,758,871	301,789,660

Schedule 2: Electric Utility Data Base

A	B	C	D	E	F	G	H	I
Formula:				**C-O**				
Utility Name	**Year**	**Electric Operating Revenues**	**Electric Utility Operating Expenses**	**Operating Revenue less Production Expense**	**Production Plant**	**Transmission Plant**	**Distribution Plant**	**General Plant**
Unitil Energy Systems	2007	157,380,917	146,738,257	50,165,948	0	0	163,970,178	11,843,607
Unitil Energy Systems	2008	160,699,518	151,912,331	52,298,040	10,383	0	173,051,216	12,638,294
Unitil Energy Systems	2009	146,121,073	137,465,565	53,654,858	10,383	0	185,797,004	12,702,712
Unitil Energy Systems	2010	140,449,238	130,385,821	64,719,417	56,372	0	198,510,589	13,739,793
Unitil Energy Systems	2011	128,467,476	116,704,507	67,286,664	56,372	0	206,563,932	14,088,309
UNS Electric Inc	2007	168,958,769	159,775,021	55,202,636	26,463,858	56,086,230	312,842,251	22,939,008
UNS Electric Inc	2008	194,910,688	184,964,104	58,175,736	26,588,575	56,687,630	333,221,584	22,741,278
UNS Electric Inc	2009	187,269,636	175,067,791	62,918,886	26,886,232	57,890,911	355,120,251	24,490,343
UNS Electric Inc	2010	215,511,584	200,529,258	67,474,744	26,806,435	59,045,212	369,880,996	25,668,157
UNS Electric Inc	2011	221,266,600	198,609,484	83,131,143	93,971,176	71,696,579	388,446,383	27,190,175
Virginia Electric & Power Co	2007	6,135,050,341	5,316,270,837	2,566,231,892	10,225,087,085	1,926,792,353	6,892,641,251	545,045,993
Virginia Electric & Power Co	2008	6,896,610,905	5,829,838,648	3,032,071,705	10,909,949,566	2,101,399,920	7,215,618,010	550,453,471
Virginia Electric & Power Co	2009	6,568,904,494	5,967,602,245	2,488,108,841	11,063,884,100	2,499,435,339	7,531,601,443	577,920,103
Virginia Electric & Power Co	2010	7,214,935,549	6,099,112,188	3,584,747,408	11,410,835,517	3,063,556,941	7,853,882,422	581,926,031
Virginia Electric & Power Co	2011	7,213,037,622	6,145,124,455	3,667,839,561	12,513,543,398	3,814,455,481	8,201,744,181	621,577,935
West Penn Power Co	2007	1,222,351,944	1,153,592,794	399,124,707	0	335,510,829	1,403,640,745	50,152,836
West Penn Power Co	2008	1,277,507,287	1,203,033,149	408,705,520	0	344,432,518	1,456,182,359	147,205,291
West Penn Power Co	2009	1,372,230,544	1,260,875,499	453,753,849	0	347,232,840	1,509,555,976	146,566,626
West Penn Power Co	2010	1,570,902,933	1,457,425,678	494,588,357	0	352,854,173	1,557,775,162	159,553,413
West Penn Power Co	2011	1,128,748,472	1,040,626,305	433,894,919	0	361,204,792	1,640,148,969	167,986,512
Westar Energy Inc	2007	997,148,129	840,913,094	529,577,456	1,537,305,619	394,185,437	840,282,292	167,126,894
Westar Energy Inc	2008	1,054,675,125	872,148,463	509,298,223	1,934,338,020	471,305,367	884,997,507	178,127,322
Westar Energy Inc	2009	1,070,490,601	883,570,492	595,283,051	2,553,381,312	559,040,932	922,804,940	179,961,251
Westar Energy Inc	2010	1,205,895,735	979,559,158	710,048,151	2,583,298,229	721,851,013	957,362,746	184,992,465
Westar Energy Inc	2011	1,240,125,727	978,701,806	749,816,772	2,690,849,410	777,715,426	994,743,925	178,769,433
Wheeling Power Co	2007	101,641,208	79,460,877	59,201,124	0	25,623,654	100,771,272	4,620,998
Wheeling Power Co	2008	110,422,239	85,851,269	61,203,969	0	25,887,202	108,338,774	4,827,543
Wheeling Power Co	2009	116,333,379	89,541,379	61,260,631	0	29,740,179	113,642,201	4,908,181
Wheeling Power Co	2010	141,130,455	114,320,845	66,995,988	0	29,949,832	117,381,116	4,913,190
Wheeling Power Co	2011	155,842,208	124,350,159	71,870,949	0	47,266,113	123,202,612	4,927,240
Wisconsin Electric Power Co	2007	2,711,188,369	2,574,871,999	1,243,857,846	2,600,970,597	-532,839	3,144,981,288	90,221,698
Wisconsin Electric Power Co	2008	2,704,611,654	2,412,774,332	922,679,062	2,936,774,369	-532,839	3,273,123,370	85,003,058
Wisconsin Electric Power Co	2009	2,704,320,197	2,404,450,049	1,131,617,595	2,948,366,626	-532,839	3,389,240,328	64,860,737
Wisconsin Electric Power Co	2010	2,976,283,059	2,650,173,971	1,273,333,475	2,981,228,925	-532,839	3,488,803,035	28,866,508
Wisconsin Electric Power Co	2011	3,234,843,698	2,922,927,699	1,457,143,452	3,321,419,779	-532,839	3,614,330,829	-22,082,161
Wisconsin Power & Light Co	2007	1,179,329,206	1,069,594,423	503,138,001	974,180,062	0	1,297,384,610	47,826,137
Wisconsin Power & Light Co	2008	1,198,926,533	1,086,959,744	510,599,514	1,143,600,898	0	1,400,881,597	52,118,884
Wisconsin Power & Light Co	2009	1,184,924,200	1,064,767,832	506,937,523	1,240,156,656	0	1,520,347,454	55,624,047
Wisconsin Power & Light Co	2010	1,238,233,308	1,064,167,336	614,758,357	1,517,489,585	0	1,620,276,603	54,615,274
Wisconsin Power & Light Co	2011	1,243,566,422	1,045,828,773	666,728,693	1,787,491,997	0	1,705,715,590	61,513,741
Wisconsin Public Service Corp	2007	1,150,307,137	1,040,113,692	465,658,536	921,128,870	0	876,685,325	28,624,971
Wisconsin Public Service Corp	2008	1,234,929,790	1,115,651,693	546,603,210	1,439,394,619	0	909,388,261	27,616,515
Wisconsin Public Service Corp	2009	1,200,342,665	1,076,501,654	579,229,702	1,705,817,616	0	927,854,459	26,976,401
Wisconsin Public Service Corp	2010	1,238,720,723	1,091,479,364	637,385,249	1,721,188,527	0	945,797,853	26,644,281
Wisconsin Public Service Corp	2011	1,240,557,205	1,106,463,527	618,638,440	1,736,598,032	0	964,827,743	27,151,416

Schedule 2: Electric Utility Data Base

A	B	J	K	L	M	N	O	P	Q	R	S
Formula:		**G+H+I-K-L-M**									
Utility Name	**Year**	**Net Plant less production**	**Accumulated Depreciation- Transmission**	**Accumulated Depreciation- Distribution**	**Accumulated Depreciation- General**	**Accumulated Depreciation- Total Utility Plant**	**O&M- Production Expense**	**O&M- Transmission Expense**	**O&M- Distribution Expense**	**O&M- Customer Account Expenses**	**O&M- Customer Service and Information Expenses**
ALLETE Inc	2007	429,737,137	106,491,969	157,278,237	62,958,239	740,758,807	429,974,219	17,998,315	21,813,788	5,982,029	7,468,791
ALLETE Inc	2008	440,994,811	110,123,099	166,685,912	64,301,497	749,452,246	362,453,373	20,751,001	21,018,608	5,870,920	9,288,034
ALLETE Inc	2009	551,710,679	152,693,300	167,147,938	66,256,600	864,944,372	360,437,497	21,911,440	20,894,304	6,268,907	10,369,824
ALLETE Inc	2010	580,789,221	160,180,158	178,423,729	70,360,274	909,379,831	420,921,764	44,218,240	22,528,184	6,515,989	11,080,709
ALLETE Inc	2011	605,544,366	167,092,767	185,615,009	75,406,494	955,420,740	401,084,606	39,715,290	23,736,704	7,023,443	12,943,804
Ameren Missouri	2007	2,640,959,379	199,877,410	1,671,512,498	232,156,722	5,157,068,197	1,134,678,113	21,509,016	182,043,229	55,932,574	7,731,648
Ameren Missouri	2008	2,850,199,384	212,170,977	1,758,124,129	249,702,641	5,243,529,779	1,163,976,481	38,692,972	147,357,900	54,925,782	10,724,602
Ameren Missouri	2009	3,069,683,474	224,311,865	1,834,759,113	265,181,020	5,438,728,228	1,046,273,641	40,065,069	191,246,237	50,274,761	12,377,901
Ameren Missouri	2010	3,188,736,043	235,587,828	1,931,759,640	204,687,596	5,601,643,484	1,166,343,052	40,105,115	181,198,100	46,954,977	11,331,381
Ameren Missouri	2011	3,293,243,578	252,820,160	2,039,587,665	203,055,247	5,810,251,336	1,293,271,015	43,597,514	196,237,696	42,217,879	17,376,700
Appalachian Power Co	2007	2,941,292,627	523,793,251	694,987,149	55,734,905	2,899,249,066	1,784,926,969	15,371,330	96,712,036	47,771,598	4,301,623
Appalachian Power Co	2008	3,105,363,683	545,988,866	721,508,664	56,014,129	2,999,722,491	2,014,222,856	12,000,067	117,537,838	43,739,772	4,178,371
Appalachian Power Co	2009	3,248,907,852	568,568,591	759,544,874	58,132,241	3,110,571,129	1,896,357,509	-5,351,336	156,770,294	38,982,148	4,290,729
Appalachian Power Co	2010	3,309,101,952	590,779,719	813,234,990	61,046,145	3,261,737,919	2,260,389,515	34,774,724	109,730,607	39,701,401	3,806,734
Appalachian Power Co	2011	3,436,064,938	607,580,490	866,478,073	62,827,573	3,415,835,935	2,135,343,294	45,482,177	90,355,092	40,124,489	4,018,820
Arizona Public Service Co	2007	4,528,980,877	485,631,331	1,144,739,323	0	4,336,766,934	1,626,463,884	50,749,093	94,462,663	67,386,636	11,184,454
Arizona Public Service Co	2008	4,646,748,882	506,960,814	1,186,103,459	174,416,346	4,460,506,459	1,793,339,513	45,009,185	106,169,715	75,589,260	12,641,506
Arizona Public Service Co	2009	4,869,030,564	531,264,395	1,234,251,561	183,917,307	4,647,183,427	1,675,779,228	46,453,354	95,644,330	74,295,835	25,456,994
Arizona Public Service Co	2010	5,205,320,403	569,007,097	1,216,775,273	144,644,882	4,779,087,353	1,530,679,261	46,538,921	92,071,726	66,343,048	51,166,156
Arizona Public Service Co	2011	5,446,527,897	591,986,997	1,266,229,281	146,378,713	4,952,911,448	1,475,752,009	85,868,702	83,265,232	56,083,703	73,402,967
Avista Corp	2007	940,255,689	144,269,157	268,572,075	43,000,801	816,649,875	379,856,712	22,316,212	22,486,704	12,489,906	11,363,893
Avista Corp	2008	1,011,346,531	151,579,025	287,538,257	43,016,649	856,572,707	530,808,921	23,354,983	25,900,985	12,369,667	16,811,273
Avista Corp	2009	1,202,614,221	158,504,412	306,761,947	0	910,060,974	512,231,177	23,894,960	25,831,106	14,416,439	25,663,667
Avista Corp	2010	1,141,600,960	165,976,498	327,916,454	45,388,645	960,938,591	596,023,790	28,461,431	27,101,341	12,936,498	29,014,939
Avista Corp	2011	1,214,276,267	174,033,587	348,254,793	48,009,683	1,012,217,393	579,224,278	29,778,012	29,764,168	14,287,247	29,533,339
Baltimore Gas & Electric Co	2007	2,465,736,826	257,871,864	1,425,623,025	39,645,537	1,723,140,426	1,500,380,569	21,092,127	124,295,050	51,857,455	6,949,710
Baltimore Gas & Electric Co	2008	2,619,679,677	270,086,531	1,508,250,746	41,481,033	1,819,818,310	1,880,105,300	25,464,450	133,042,191	71,158,491	4,678,658
Baltimore Gas & Electric Co	2009	2,793,572,222	283,852,109	1,590,482,886	45,938,714	1,920,273,709	1,840,870,377	28,280,064	130,272,738	73,592,176	5,287,036
Baltimore Gas & Electric Co	2010	3,050,426,420	297,835,256	1,671,800,848	42,845,315	2,012,481,419	1,680,944,059	29,913,370	170,183,921	71,353,337	5,717,893
Baltimore Gas & Electric Co	2011	3,308,838,747	306,290,527	1,760,144,875	41,847,239	2,108,282,641	1,184,594,098	35,355,092	205,584,349	76,919,490	4,160,353
CenterPoint Energy Houston Electric LLC	2007	3,918,158,999	444,068,272	1,990,228,296	315,515,233	2,750,962,004	0	289,607,826	154,761,600	29,284,619	23,598,346
CenterPoint Energy Houston Electric LLC	2008	4,019,076,480	463,406,113	2,001,246,787	334,054,351	2,799,857,490	0	332,316,609	153,125,411	34,473,284	27,008,779
CenterPoint Energy Houston Electric LLC	2009	4,111,524,680	486,275,911	2,135,959,973	259,195,832	2,882,581,954	0	354,998,154	190,221,905	32,696,721	28,689,058
CenterPoint Energy Houston Electric LLC	2010	4,213,297,732	514,954,644	2,206,709,899	254,408,596	2,977,223,378	0	380,745,178	212,747,383	33,939,216	32,225,493
CenterPoint Energy Houston Electric LLC	2011	4,389,334,461	542,406,420	2,242,711,396	252,576,995	3,038,845,050	0	424,092,836	216,921,946	29,719,279	33,545,272
Central Hudson Gas & Electric Corp	2007	526,703,571	70,418,704	186,074,368	337,296	269,348,379	384,026,087	10,086,320	30,543,624	14,746,050	12,368,999
Central Hudson Gas & Electric Corp	2008	562,042,860	72,949,056	194,912,087	359,538	281,209,225	365,801,151	9,803,955	35,735,877	17,257,307	14,539,511
Central Hudson Gas & Electric Corp	2009	607,821,222	75,054,008	191,587,695	415,230	280,106,258	261,363,515	10,239,359	35,503,660	18,287,381	24,038,683
Central Hudson Gas & Electric Corp	2010	651,466,453	77,943,796	199,099,024	437,643	291,259,178	246,699,911	9,359,400	41,694,646	16,009,134	27,223,121
Central Hudson Gas & Electric Corp	2011	703,266,423	75,019,012	191,564,895	463,705	281,332,710	206,397,800	8,502,437	49,148,833	18,247,962	37,803,404
Central Vermont Public Service Corp	2007	218,078,621	25,387,355	127,656,037	11,819,295	242,695,229	174,860,758	23,167,498	32,891,361	7,204,331	1,183,839
Central Vermont Public Service Corp	2008	226,310,803	26,627,373	131,776,451	13,319,617	252,457,220	180,363,637	27,917,737	32,320,900	7,414,921	1,254,968
Central Vermont Public Service Corp	2009	245,618,955	28,850,134	135,846,682	15,342,337	263,788,513	171,535,677	33,782,941	30,588,399	8,919,254	1,708,725
Central Vermont Public Service Corp	2010	253,019,391	30,282,332	141,119,323	17,726,550	275,515,916	174,876,151	24,731,069	35,280,485	6,418,340	1,753,296
Central Vermont Public Service Corp	2011	264,085,819	31,410,082	146,139,642	20,276,798	286,147,594	172,224,188	40,207,693	41,127,793	8,385,697	2,037,660
Chugach Electric Association Inc	2007	351,440,095	121,001,366	106,668,705	0	367,391,921	156,143,279	6,781,166	13,716,105	4,296,117	603,761
Chugach Electric Association Inc	2008	322,017,558	126,428,348	113,448,019	26,742,177	389,002,139	186,099,951	5,841,405	12,398,832	4,770,165	626,497
Chugach Electric Association Inc	2009	315,441,687	132,937,255	122,076,511	27,480,294	420,464,808	188,514,148	5,709,578	12,740,381	4,588,702	670,646
Chugach Electric Association Inc	2010	346,272,296	139,409,943	129,407,790	0	446,582,318	156,659,571	5,697,446	12,216,252	4,410,979	912,572
Chugach Electric Association Inc	2011	313,085,622	145,129,605	137,774,079	26,290,539	470,282,210	181,894,459	6,809,401	13,387,477	4,817,451	647,864
CLECO Power LLC	2007	854,476,702	142,613,421	350,063,176	17,908,934	859,230,197	689,366,195	16,401,812	25,464,269	17,057,898	5,315,652
CLECO Power LLC	2008	905,545,018	148,832,952	357,606,047	21,729,709	885,144,047	735,684,763	16,235,452	23,887,507	17,363,159	4,773,113
CLECO Power LLC	2009	964,034,735	154,798,198	379,974,689	26,015,413	931,800,630	514,746,254	14,478,887	24,885,011	15,626,939	4,838,444
CLECO Power LLC	2010	1,036,488,887	161,160,697	395,150,265	20,242,651	1,024,901,667	568,995,919	16,787,676	27,470,440	15,874,230	7,183,761
CLECO Power LLC	2011	1,156,085,688	170,141,002	408,568,937	25,344,226	1,085,930,466	519,705,333	17,836,554	28,996,202	16,042,255	6,978,147
Cleveland Electric Illuminating Co (The)	2007	1,251,880,659	162,512,335	602,266,381	40,158,604	818,652,922	801,689,617	119,087,170	52,795,730	32,441,214	3,274,767
Cleveland Electric Illuminating Co (The)	2008	1,321,935,711	169,135,596	630,426,684	41,954,286	855,427,850	777,325,803	126,571,930	62,065,670	27,816,445	3,502,306
Cleveland Electric Illuminating Co (The)	2009	1,363,705,562	176,225,793	664,318,843	44,406,718	898,862,637	987,901,849	28,889,262	38,396,299	25,446,850	3,231,415
Cleveland Electric Illuminating Co (The)	2010	1,401,734,910	182,653,508	699,451,885	47,495,249	943,511,636	490,585,795	4,616,676	42,838,939	26,352,450	3,594,423
Cleveland Electric Illuminating Co (The)	2011	1,499,758,160	189,546,065	741,193,709	50,582,768	995,233,536	236,421,039	28,091,660	39,997,748	19,470,975	10,120,627
Commonwealth Edison Co	2007	9,479,449,466	848,855,374	4,765,920,959	378,728,040	5,993,504,373	3,591,772,065	239,667,042	372,460,830	213,340,786	18,092,405
Commonwealth Edison Co	2008	10,233,136,739	876,722,021	4,795,381,793	399,493,477	6,071,597,291	3,260,667,394	391,983,821	390,075,139	223,556,795	37,684,217
Commonwealth Edison Co	2009	10,583,550,549	909,032,183	4,991,418,587	440,743,338	6,341,194,108	2,755,080,247	389,344,768	297,464,867	244,746,467	69,781,585
Commonwealth Edison Co	2010	10,983,964,494	935,363,421	5,135,789,439	478,425,493	6,549,578,353	2,996,529,845	391,936,413	313,141,146	210,714,394	105,918,598
Commonwealth Edison Co	2011	11,535,000,293	968,695,737	5,317,528,333	527,162,520	6,813,386,590	2,821,748,364	343,540,345	414,483,591	229,435,937	123,268,376
Consolidated Edison Co of New York Inc	2007	11,340,142,164	841,475,477	2,405,521,058	0	3,198,694,335	3,432,637,080	151,535,609	434,117,831	194,201,067	7,559,725
Consolidated Edison Co of New York Inc	2008	12,575,379,373	877,938,174	2,501,777,513	0	3,335,008,311	3,661,994,420	165,224,963	466,766,952	215,721,000	13,906,478
Consolidated Edison Co of New York Inc	2009	13,456,061,382	919,396,568	2,641,981,881	0	3,532,658,385	3,051,980,657	166,182,379	457,523,856	230,740,732	21,623,245
Consolidated Edison Co of New York Inc	2010	14,366,547,346	973,054,561	2,832,339,900	0	3,795,082,336	3,038,980,177	162,662,359	442,749,889	225,667,396	25,573,958
Consolidated Edison Co of New York Inc	2011	15,247,433,531	1,039,153,070	3,012,972,095	0	4,054,648,564	2,647,545,719	171,343,312	457,250,400	234,023,319	25,893,577
Consumers Energy Co	2007	2,750,720,492	0	1,773,049,144	80,546,460	2,845,093,460	1,952,393,313	120,150,023	150,721,106	55,371,745	31,478,670
Consumers Energy Co	2008	3,011,905,047	0	1,876,431,594	0	3,018,290,334	1,860,545,860	168,481,772	154,121,011	65,631,618	31,113,476
Consumers Energy Co	2009	3,056,324,336	0	1,968,972,030	97,099,604	3,222,700,151	1,654,638,676	225,194,652	142,488,291	61,548,937	52,325,929
Consumers Energy Co	2010	3,225,625,521	0	2,069,902,427	108,302,097	3,386,617,535	1,778,801,327	240,920,265	133,282,635	70,360,443	63,443,032
Consumers Energy Co	2011	3,513,827,141	0	2,182,576,091	0	3,532,895,642	1,855,457,927	259,239,453	175,986,480	83,684,350	79,255,279

Schedule 2: Electric Utility Data Base

A	B	J	K	L	M	N	O	P	Q	R	S
Formula:		G+H+I-K-L-M									
Utility Name	Year	Net Plant less production	Accumulated Depreciation-Transmission	Accumulated Depreciation-Distribution	Accumulated Depreciation-General	Accumulated Depreciation-Total Utility Plant	O&M- Production Expense	O&M- Transmission Expense	O&M- Distribution Expense	O&M- Customer Account Expenses	O&M- Customer Service and Information Expenses
Detroit Edison Co (The)	2007	3,933,096,375	21,308,075	2,125,444,003	0	5,637,855,055	1,800,647,177	268,301,225	250,884,595	135,730,183	60,042,213
Detroit Edison Co (The)	2008	3,781,655,116	22,697,418	2,190,243,964	404,932,239	5,784,541,279	1,891,829,496	274,067,620	243,484,077	163,224,717	61,280,890
Detroit Edison Co (The)	2009	4,404,482,474	23,993,056	2,296,065,908	0	6,058,523,702	1,602,729,032	277,167,453	220,035,305	154,861,316	72,673,394
Detroit Edison Co (The)	2010	4,085,594,943	26,130,319	2,398,684,648	475,383,834	6,313,021,187	1,703,034,425	316,843,053	256,031,229	145,028,200	77,549,551
Detroit Edison Co (The)	2011	4,588,643,765	25,930,431	2,513,407,021	0	6,392,328,379	1,865,655,622	296,514,539	293,444,402	146,875,214	61,964,828
Duke Energy Carolinas	2007	6,206,053,266	1,036,436,719	3,213,311,091	46,658,588	9,618,484,271	2,387,518,062	38,656,773	171,029,030	70,946,351	27,478,127
Duke Energy Carolinas	2008	6,452,119,343	1,081,991,904	3,404,543,062	35,703,522	10,611,466,940	2,695,245,162	56,069,604	176,402,283	69,501,913	20,178,968
Duke Energy Carolinas	2009	6,686,213,179	1,112,219,492	3,536,786,275	64,212,750	11,093,653,261	2,390,261,377	44,851,785	182,933,748	82,546,379	20,523,177
Duke Energy Carolinas	2010	6,904,488,749	1,150,138,358	3,703,946,193	75,770,594	11,545,742,584	2,824,606,701	51,105,461	192,807,011	98,885,591	26,232,482
Duke Energy Carolinas	2011	7,314,398,772	1,184,888,115	3,864,431,654	0	11,909,508,954	2,888,315,084	53,698,495	205,379,124	104,406,462	35,453,117
Duke Energy Indiana	2007	1,841,090,717	356,360,635	832,186,615	88,797,545	3,151,298,934	987,182,533	32,611,042	45,701,434	43,792,306	7,551,185
Duke Energy Indiana	2008	1,892,362,410	347,023,473	917,142,385	71,953,612	3,288,347,906	1,211,171,386	36,046,668	85,237,846	41,110,607	6,968,906
Duke Energy Indiana	2009	1,945,382,553	386,471,722	948,352,283	107,444,226	3,537,623,114	1,076,720,785	30,828,204	89,029,404	43,309,901	6,179,999
Duke Energy Indiana	2010	1,982,852,864	404,370,636	991,247,217	123,120,855	3,784,022,143	1,132,486,247	41,010,715	59,029,004	49,300,874	9,875,339
Duke Energy Indiana	2011	2,024,500,372	422,908,169	1,024,577,632	133,398,138	3,915,139,874	1,208,028,664	35,642,579	106,991,180	52,027,691	13,514,150
Duke Energy Ohio	2007	1,512,930,929	200,725,800	551,951,422	13,187,648	2,426,465,284	1,508,661,886	20,201,602	49,379,271	43,717,919	5,663,082
Duke Energy Ohio	2008	1,572,033,262	211,856,851	577,813,181	13,410,538	2,550,439,837	1,280,831,549	14,280,448	53,627,205	56,488,266	4,871,627
Duke Energy Ohio	2009	1,663,048,708	223,014,513	595,121,020	15,633,655	2,586,015,732	1,194,209,224	25,140,205	57,405,551	42,813,882	4,102,316
Duke Energy Ohio	2010	1,750,007,080	233,399,352	625,814,226	10,627,310	2,525,100,502	1,123,321,655	17,959,496	65,674,991	50,773,329	8,733,599
Duke Energy Ohio	2011	1,739,207,258	222,775,806	641,367,306	21,340,622	2,112,499,084	994,730,206	38,879,952	60,235,598	34,658,860	15,641,325
Empire District Electric Co (The)	2007	523,978,257	60,143,640	223,385,220	38,486,280	509,049,897	212,947,353	5,295,181	22,656,910	9,749,981	1,353,075
Empire District Electric Co (The)	2008	535,075,537	64,656,974	241,219,787	42,162,765	552,588,713	227,707,865	6,213,120	19,455,521	8,919,936	1,348,818
Empire District Electric Co (The)	2009	543,615,279	69,478,122	258,060,069	44,744,806	591,397,123	207,796,444	6,564,559	23,117,365	9,533,960	1,324,495
Empire District Electric Co (The)	2010	563,345,041	73,536,969	278,624,707	49,267,440	634,503,807	227,758,151	8,829,342	24,797,058	11,050,141	1,597,804
Empire District Electric Co (The)	2011	590,431,378	78,138,186	296,223,802	51,914,773	680,173,949	233,148,708	10,963,006	26,952,617	9,704,513	1,830,651
Fitchburg Gas & Electric Light Co	2007	56,659,873	3,045,719	27,950,991	1,648,402	32,645,112	43,727,230	2,105,467	1,807,139	2,292,526	1,063,437
Fitchburg Gas & Electric Light Co	2008	59,771,936	3,357,159	27,496,373	1,817,889	32,671,421	40,030,413	4,366,260	1,941,255	2,617,023	904,468
Fitchburg Gas & Electric Light Co	2009	66,344,900	3,726,713	30,249,521	1,905,309	35,881,543	35,148,264	5,521,525	1,857,210	2,448,143	1,287,361
Fitchburg Gas & Electric Light Co	2010	67,950,673	4,091,505	33,667,083	2,093,898	39,852,486	32,589,393	6,020,367	2,088,680	2,582,904	2,141,656
Fitchburg Gas & Electric Light Co	2011	68,766,885	4,532,665	35,704,100	1,137,392	41,374,157	27,362,841	5,385,201	2,577,487	2,551,999	3,273,050
Florida Power & Light Co	2007	8,716,061,618	1,253,686,808	3,584,793,244	77,515,058	11,627,878,333	7,314,173,274	60,818,552	278,523,541	131,893,714	86,939,039
Florida Power & Light Co	2008	9,151,133,150	1,300,679,341	3,847,771,180	-34,719,402	11,815,972,425	7,365,167,256	66,707,248	272,152,365	149,420,524	102,494,808
Florida Power & Light Co	2009	9,614,333,917	1,353,965,319	4,112,981,391	-135,385,196	12,228,428,978	6,812,947,643	58,039,850	244,834,579	149,319,806	102,721,315
Florida Power & Light Co	2010	9,334,874,335	1,401,112,470	4,246,502,271	317,198,865	12,491,470,329	5,637,001,767	76,809,579	265,078,147	134,298,779	133,957,761
Florida Power & Light Co	2011	9,653,062,000	1,476,378,546	4,397,427,510	274,370,578	12,586,633,948	5,632,612,412	90,581,819	284,014,637	136,793,781	145,032,196
Idaho Power Co	2007	1,353,648,656	221,027,699	424,878,403	86,737,285	1,430,468,593	388,712,334	26,659,257	44,612,561	16,065,664	23,097,575
Idaho Power Co	2008	1,475,902,334	230,292,212	441,040,082	91,848,631	1,486,751,090	420,196,323	23,588,205	46,222,123	21,551,190	28,834,452
Idaho Power Co	2009	1,528,778,962	252,188,686	469,434,706	95,081,841	1,693,322,507	465,530,068	23,490,832	45,461,676	24,139,078	41,869,927
Idaho Power Co	2010	1,621,687,752	264,169,778	497,188,284	101,003,040	1,750,735,946	440,578,820	23,606,246	45,808,183	22,065,567	53,208,148
Idaho Power Co	2011	1,670,056,291	270,518,301	528,960,145	108,011,457	1,818,635,521	428,273,552	26,590,676	45,858,492	20,094,962	45,177,396
Indiana Michigan Power Co	2007	1,401,089,930	484,949,300	432,020,851	24,955,137	3,097,920,046	1,250,311,059	-9,642,848	60,548,300	22,185,384	2,919,804
Indiana Michigan Power Co	2008	1,538,763,702	493,992,419	434,351,312	22,210,516	3,101,707,576	1,418,245,089	-12,232,846	70,804,747	21,318,212	3,201,319
Indiana Michigan Power Co	2009	1,639,058,959	504,959,262	443,905,896	23,904,062	3,183,226,402	1,266,511,562	-12,458,696	66,872,997	19,953,625	4,467,924
Indiana Michigan Power Co	2010	1,694,898,212	519,354,689	459,822,822	25,674,522	3,257,025,809	1,405,406,377	8,656,323	71,312,157	19,785,191	7,842,514
Indiana Michigan Power Co	2011	1,774,458,095	531,736,589	476,915,254	26,455,688	3,296,683,179	1,366,078,064	34,504,129	50,231,575	20,638,291	15,813,181
Indianapolis Power & Light	2007	520,890,757	122,359,634	753,785,641	53,439,166	1,957,787,658	397,081,936	10,108,080	31,630,965	18,269,040	1,949,295
Indianapolis Power & Light	2008	507,300,823	119,663,722	804,175,938	58,844,991	2,089,444,355	443,813,327	11,101,532	39,571,808	19,288,692	1,701,464
Indianapolis Power & Light	2009	496,563,200	124,079,986	856,099,320	64,698,519	2,222,519,606	446,721,176	10,883,641	35,468,656	19,323,287	1,340,016
Indianapolis Power & Light	2010	494,612,880	139,556,478	893,440,795	59,518,317	2,339,348,942	519,649,562	11,261,017	35,618,362	19,752,199	1,788,493
Indianapolis Power & Light	2011	483,675,095	143,691,629	937,888,593	63,317,165	2,426,492,728	569,626,873	11,500,700	35,397,842	19,651,157	2,063,643
Interstate Power & Light Co	2007	1,107,277,919	0	611,693,089	60,229,780	1,519,070,074	671,798,623	25,798,678	31,597,012	17,338,971	32,654,202
Interstate Power & Light Co	2008	1,183,696,755	0	634,945,214	60,933,404	1,535,112,410	667,256,146	92,206,615	27,689,844	20,044,623	32,148,471
Interstate Power & Light Co	2009	1,264,820,304	0	662,312,838	64,542,524	1,642,179,083	670,307,111	134,351,796	23,100,300	19,651,138	36,866,265
Interstate Power & Light Co	2010	1,366,952,628	0	686,438,808	52,687,006	1,672,835,237	665,054,490	181,994,476	25,781,994	15,455,125	48,086,072
Interstate Power & Light Co	2011	1,465,010,623	0	708,479,765	49,532,098	1,767,830,240	657,333,413	222,171,524	24,408,029	18,261,992	43,264,177
Jersey Central Power & Light Co	2007	2,438,058,621	292,158,069	1,113,384,331	151,794,653	1,646,738,141	1,966,426,375	28,723,653	115,500,526	37,309,332	85,130,769
Jersey Central Power & Light Co	2008	2,539,535,761	289,473,834	1,136,413,958	156,282,581	1,673,671,332	2,210,998,842	25,750,991	113,114,858	38,592,092	98,281,349
Jersey Central Power & Light Co	2009	2,634,958,950	293,459,269	1,182,680,690	162,252,160	1,732,302,703	1,785,790,990	25,249,534	75,945,317	32,957,459	104,874,573
Jersey Central Power & Light Co	2010	2,710,814,217	302,589,897	1,224,063,389	169,972,614	1,766,016,804	1,740,625,759	22,516,662	89,786,661	31,515,318	108,485,624
Jersey Central Power & Light Co	2011	2,926,915,520	314,184,738	1,293,843,740	169,977,841	1,848,180,622	1,386,052,662	22,955,520	143,935,863	35,994,864	119,589,441
Kentucky Power Co	2007	672,380,575	130,467,612	127,572,674	5,848,893	470,175,005	403,620,121	8,316,491	24,567,559	7,711,472	2,012,559
Kentucky Power Co	2008	718,505,745	135,462,933	133,637,433	6,568,989	485,838,475	499,308,352	6,738,351	26,602,282	7,384,552	1,670,231
Kentucky Power Co	2009	752,513,681	141,779,874	139,979,041	7,194,870	514,678,951	457,856,290	-821,880	29,693,612	6,892,404	1,847,874
Kentucky Power Co	2010	762,625,459	146,905,185	151,176,730	7,580,459	548,979,607	478,637,653	2,765,252	39,642,497	6,506,720	2,793,891
Kentucky Power Co	2011	779,481,859	152,659,695	162,703,363	8,027,395	580,174,789	485,092,926	10,834,895	44,369,059	7,043,916	3,536,508
Kingsport Power Co	2007	69,994,577	8,886,804	32,620,646	570,173	42,077,623	75,843,333	430,996	3,636,820	1,796,503	160,667
Kingsport Power Co	2008	72,018,096	9,259,738	34,413,666	597,762	44,271,166	92,230,150	543,613	4,440,967	1,823,907	124,362
Kingsport Power Co	2009	73,482,687	9,708,936	36,858,046	632,975	47,199,957	123,547,148	471,489	7,864,233	1,749,736	136,428
Kingsport Power Co	2010	76,436,643	9,870,172	39,337,935	634,319	49,842,426	123,834,031	535,156	2,326,363	2,207,233	124,226
Kingsport Power Co	2011	79,379,927	10,204,475	42,425,418	661,283	53,291,176	126,737,709	478,091	5,057,866	1,635,396	58,818
Madison Gas & Electric Co	2007	251,225,561	1,829,839	116,302,832	8,773,759	268,610,130	169,561,556	19,814,365	12,313,681	6,817,777	4,211,824
Madison Gas & Electric Co	2008	258,441,165	1,884,694	125,103,454	8,733,346	287,327,411	177,383,242	24,085,828	13,013,741	7,303,912	8,657,247
Madison Gas & Electric Co	2009	279,985,471	0	131,898,623	9,207,836	305,792,286	152,950,382	24,884,218	11,425,606	6,708,818	8,562,956
Madison Gas & Electric Co	2010	297,201,412	0	137,794,526	10,236,242	326,651,489	146,230,518	29,715,196	12,799,450	6,975,125	8,562,278
Madison Gas & Electric Co	2011	327,069,947	0	144,446,921	10,210,368	347,228,492	146,727,864	29,087,110	13,540,480	6,816,238	8,335,104

Schedule 2: Electric Utility Data Base

A	B	J	K	L	M	N	O	P	Q	R	S
Formula:		G+H+I-K-L-M									
Utility Name	Year	Net Plant less production	Accumulated Depreciation-Transmission	Accumulated Depreciation-Distribution	Accumulated Depreciation-General	Accumulated Depreciation-Total Utility Plant	O&M- Production Expense	O&M- Transmission Expense	O&M- Distribution Expense	O&M- Customer Account Expenses	O&M- Customer Service and Information Expenses
MDU Resources Group Inc	2007	162,664,555	76,461,290	104,446,621	8,945,928	388,933,401	89,844,670	7,102,930	11,315,706	4,038,101	160,090
MDU Resources Group Inc	2008	179,512,923	78,504,432	108,519,648	9,539,594	403,399,367	93,341,925	7,359,636	11,292,573	3,840,312	226,457
MDU Resources Group Inc	2009	185,964,802	80,431,072	114,675,034	9,957,909	419,780,204	85,106,421	7,726,338	10,546,254	3,699,548	333,509
MDU Resources Group Inc	2010	198,915,997	82,730,353	119,513,556	9,966,833	438,372,147	84,425,159	9,043,219	10,637,911	3,387,264	370,057
MDU Resources Group Inc	2011	221,070,578	84,617,667	123,851,306	8,944,556	455,960,813	88,089,046	8,667,928	11,708,696	3,622,667	405,839
Metropolitan Edison Co	2007	1,208,954,334	123,624,662	418,620,288	101,249,565	740,926,766	795,442,156	298,561,877	50,335,894	25,940,518	15,011,225
Metropolitan Edison Co	2008	1,274,936,518	127,353,814	437,759,738	102,567,529	765,113,332	900,860,681	322,217,380	44,378,985	25,609,827	22,330,002
Metropolitan Edison Co	2009	1,342,633,017	130,478,952	461,339,346	105,193,007	792,332,459	905,018,995	155,080,349	33,373,649	23,405,368	26,278,380
Metropolitan Edison Co	2010	1,393,618,122	134,219,896	486,306,581	108,978,142	824,825,773	959,032,311	270,386,696	37,612,011	22,459,796	35,160,098
Metropolitan Edison Co	2011	1,574,134,274	136,439,162	523,775,280	108,030,528	863,566,125	627,154,240	10,929,489	48,484,714	23,121,474	51,285,326
Monongahela Power Co	2007	802,328,170	146,692,737	407,264,681	25,715,969	1,308,665,725	602,632,938	16,276,239	32,082,473	11,069,586	1,019,882
Monongahela Power Co	2008	832,596,185	152,373,051	426,745,428	28,420,630	1,347,187,498	551,437,879	14,323,974	38,926,662	11,008,644	1,397,282
Monongahela Power Co	2009	876,600,697	157,932,356	448,577,763	30,500,271	1,390,167,175	554,750,068	17,365,080	46,802,719	12,139,135	1,386,866
Monongahela Power Co	2010	915,592,639	161,166,376	470,294,856	33,969,013	1,455,544,148	653,680,132	18,390,458	33,482,406	14,085,415	963,086
Monongahela Power Co	2011	984,087,461	161,021,517	492,913,800	35,731,709	1,278,060,557	746,031,427	117,922,228	31,191,505	12,282,356	1,183,962
Northern States Power Co (Minnesota)	2007	2,712,567,172	508,152,803	1,059,303,665	67,320,399	4,411,612,245	2,048,677,220	133,902,663	100,502,703	62,638,211	69,342,011
Northern States Power Co (Minnesota)	2008	2,897,161,820	535,095,132	1,113,764,285	76,476,479	4,570,036,318	2,056,027,012	147,078,109	102,935,470	64,637,938	60,978,215
Northern States Power Co (Minnesota)	2009	3,029,512,947	567,039,152	1,180,653,906	81,081,227	4,662,239,753	1,817,967,061	163,909,646	102,529,690	60,986,493	61,586,236
Northern States Power Co (Minnesota)	2010	3,175,858,355	601,394,772	1,245,584,539	96,785,030	4,831,746,559	2,037,639,228	174,351,132	109,895,709	58,721,875	80,375,171
Northern States Power Co (Minnesota)	2011	3,411,667,832	624,714,894	1,287,799,079	101,133,381	4,986,546,238	1,960,417,575	195,079,446	112,987,360	59,247,577	116,322,177
Northern States Power Co (Wisconsin)	2007	532,511,063	143,223,534	251,284,899	20,369,189	639,568,286	391,524,283	34,200,118	20,750,545	10,696,859	7,761,069
Northern States Power Co (Wisconsin)	2008	572,925,767	151,975,203	268,039,662	23,131,906	675,442,622	405,771,274	38,541,466	19,805,087	10,859,557	9,098,190
Northern States Power Co (Wisconsin)	2009	588,371,487	161,025,255	284,485,448	23,104,745	712,877,376	397,367,767	43,398,491	19,407,930	11,062,425	9,719,265
Northern States Power Co (Wisconsin)	2010	657,857,639	169,869,678	301,381,736	26,906,632	749,970,562	420,839,015	48,299,941	21,262,310	10,190,184	10,970,060
Northern States Power Co (Wisconsin)	2011	711,649,443	180,263,246	319,613,012	27,671,586	788,098,811	441,918,371	49,956,663	24,021,194	9,583,107	10,661,891
NorthWestern Corp	2007	894,901,764	233,813,346	437,511,601	39,877,291	853,295,437	458,106,902	26,382,742	34,840,321	9,875,953	5,250,620
NorthWestern Corp	2008	907,818,471	250,398,826	466,506,333	45,082,728	907,832,081	546,796,792	27,056,639	38,289,229	10,416,866	5,894,519
NorthWestern Corp	2009	912,834,266	263,797,978	499,653,184	47,698,432	981,524,918	387,975,654	28,901,168	35,738,568	10,649,814	5,832,058
NorthWestern Corp	2010	934,157,956	280,042,898	533,973,059	50,571,265	1,051,396,930	394,022,019	31,137,497	40,858,352	10,394,519	6,100,375
NorthWestern Corp	2011	969,324,832	296,487,684	562,416,660	54,209,405	1,120,575,128	358,942,224	28,991,483	39,301,467	11,194,245	6,237,049
NSTAR Electric Co	2007	3,307,425,472	298,010,609	914,915,670	45,275,448	1,258,201,727	1,413,968,531	146,566,128	127,177,993	55,247,004	60,358,639
NSTAR Electric Co	2008	3,552,942,469	317,154,742	974,022,631	51,637,814	1,342,815,187	1,460,105,095	180,569,316	128,984,755	57,734,544	61,912,218
NSTAR Electric Co	2009	3,753,852,037	337,491,052	1,044,824,456	59,378,446	1,441,693,954	1,216,983,240	226,729,789	116,775,830	58,153,139	74,847,953
NSTAR Electric Co	2010	3,873,179,917	357,324,350	1,104,362,518	66,433,323	1,528,120,191	1,054,988,038	285,783,766	117,069,154	59,258,688	110,130,855
NSTAR Electric Co	2011	4,031,886,493	373,136,621	1,187,344,227	62,122,279	1,622,603,127	976,400,859	282,101,634	128,136,560	57,174,941	168,941,627
Ohio Edison Co	2007	1,355,074,733	85,304,267	702,423,429	51,581,456	918,271,506	1,292,109,758	173,071,722	79,267,378	48,783,611	4,511,180
Ohio Edison Co	2008	1,430,493,269	88,831,913	739,043,653	54,757,983	939,241,329	1,334,296,009	184,510,007	85,367,149	39,707,521	4,797,989
Ohio Edison Co	2009	1,482,551,147	92,268,494	775,372,875	55,958,704	980,340,891	1,499,789,251	51,702,056	61,648,408	37,838,073	4,449,140
Ohio Edison Co	2010	1,530,175,516	94,292,505	811,678,789	57,949,149	1,012,505,462	875,534,681	2,963,201	48,693,719	25,684,022	4,809,162
Ohio Edison Co	2011	1,646,393,518	97,353,987	853,369,034	62,255,879	1,061,759,540	640,510,201	57,676,533	49,901,851	25,879,614	25,347,939
Ohio Power Co	2007	2,857,601,221	677,422,960	1,113,279,017	85,751,971	4,567,119,275	2,611,782,493	74,588,945	128,857,366	86,082,408	8,319,820
Ohio Power Co	2008	3,069,312,595	700,903,337	1,160,302,851	90,742,028	4,791,011,522	3,125,149,612	152,798,828	131,914,826	111,393,582	8,014,422
Ohio Power Co	2009	3,290,986,874	731,326,503	1,214,763,627	93,875,359	5,334,603,839	2,588,725,383	113,411,514	153,805,118	96,300,176	6,421,910
Ohio Power Co	2010	3,402,091,907	763,315,049	1,286,930,770	96,890,606	5,792,228,106	2,839,717,748	121,998,514	178,627,286	117,276,340	61,881,070
Ohio Power Co	2011	3,478,026,067	783,570,503	1,363,681,942	88,756,804	5,978,093,131	3,004,360,758	49,560,828	141,745,304	140,198,761	95,988,434
Oklahoma Gas & Electric Co	2007	2,057,687,893	292,949,692	800,547,103	73,140,707	2,460,639,641	1,197,002,359	23,804,917	45,198,278	27,435,888	7,649,878
Oklahoma Gas & Electric Co	2008	2,270,680,894	314,201,751	835,245,654	77,713,764	2,613,180,559	1,309,787,986	27,714,955	59,613,708	28,217,956	8,151,199
Oklahoma Gas & Electric Co	2009	2,428,205,391	326,911,892	880,840,133	81,727,175	2,721,766,810	1,001,325,012	29,685,276	76,867,128	25,823,074	11,226,792
Oklahoma Gas & Electric Co	2010	2,784,997,614	345,782,471	924,322,934	87,415,944	2,813,281,915	1,208,188,368	49,028,128	82,731,540	26,417,671	19,873,466
Oklahoma Gas & Electric Co	2011	3,026,075,638	368,791,898	956,630,864	97,576,075	2,929,516,357	1,211,304,935	72,357,175	87,918,766	28,257,508	25,291,895
Oncor Electric Delivery	2007	7,821,678,712	932,262,224	2,832,047,755	103,469,024	3,867,779,003	0	388,264,686	206,151,085	42,228,590	42,160,656
Oncor Electric Delivery	2008	8,308,508,274	976,080,269	3,013,536,966	88,325,410	4,077,942,645	0	394,705,291	214,142,898	37,785,549	44,204,698
Oncor Electric Delivery	2009	8,693,066,407	1,033,964,611	3,208,706,641	97,948,905	4,340,620,157	0	440,977,373	219,479,872	34,025,635	54,414,227
Oncor Electric Delivery	2010	9,205,822,117	1,156,857,681	3,406,654,719	104,923,262	4,668,435,662	0	444,501,539	192,936,500	31,991,587	45,992,079
Oncor Electric Delivery	2011	9,818,778,830	1,226,574,672	3,683,069,595	120,530,059	5,030,174,326	0	493,720,547	204,333,773	32,576,561	42,108,694
Orange & Rockland Utilities Inc	2007	500,725,301	46,505,947	161,211,221	0	227,028,995	274,436,018	7,814,290	32,367,576	14,056,740	9,808,987
Orange & Rockland Utilities Inc	2008	512,419,356	48,748,421	170,926,652	27,824,465	247,499,538	300,055,117	9,425,224	36,128,166	14,544,658	11,672,643
Orange & Rockland Utilities Inc	2009	536,393,864	51,548,167	181,048,170	28,652,230	261,248,567	201,789,632	10,938,782	33,579,979	15,191,494	18,904,631
Orange & Rockland Utilities Inc	2010	553,026,078	55,021,764	193,333,436	29,405,215	277,760,415	214,801,038	9,643,071	37,481,772	15,202,680	22,958,305
Orange & Rockland Utilities Inc	2011	656,445,713	58,764,834	206,015,287	0	296,324,130	175,754,926	10,957,065	38,886,945	15,009,780	18,924,181
Pacific Gas & Electric Co	2007	12,245,326,369	1,750,241,126	6,815,912,539	509,679,845	17,147,503,848	3,902,134,788	176,055,957	498,388,177	285,996,085	457,708,043
Pacific Gas & Electric Co	2008	13,010,284,659	1,796,857,428	7,242,751,862	508,462,771	17,399,505,092	4,945,282,421	208,842,255	532,969,503	269,713,816	729,450,354
Pacific Gas & Electric Co	2009	14,332,479,502	1,889,927,398	7,493,923,932	509,477,372	17,533,245,003	4,212,043,419	201,451,121	485,303,652	242,670,866	692,486,642
Pacific Gas & Electric Co	2010	15,604,288,904	1,980,212,002	7,779,678,286	513,847,659	18,016,805,331	4,349,281,207	208,134,999	506,219,285	219,692,544	686,932,710
Pacific Gas & Electric Co	2011	16,298,733,078	2,089,647,354	8,583,970,817	505,396,617	19,049,843,021	4,538,153,107	204,857,909	600,835,792	240,599,036	700,840,483
PECO Energy Co	2007	3,359,679,168	416,743,473	1,153,608,120	20,789,520	1,591,141,113	2,110,171,726	291,135,440	158,529,536	153,904,015	10,369,800
PECO Energy Co	2008	3,535,565,578	424,312,197	1,197,466,401	15,929,485	1,637,708,083	2,134,909,653	311,646,922	168,495,904	237,619,387	11,342,050
PECO Energy Co	2009	3,714,467,101	417,080,198	1,258,552,096	17,924,658	1,693,556,952	2,030,923,373	283,611,424	171,033,598	155,164,567	12,524,535
PECO Energy Co	2010	3,880,310,737	421,781,381	1,316,057,592	16,749,030	1,754,588,003	2,112,686,952	288,554,131	204,150,806	155,453,695	64,356,329
PECO Energy Co	2011	4,222,669,843	429,410,185	1,392,932,683	19,392,970	1,841,735,838	1,443,511,271	156,492,584	222,327,446	164,693,232	65,657,199
Pennsylvania Electric Co	2007	1,369,056,770	163,804,587	542,240,775	73,340,016	828,101,502	790,896,083	127,585,399	56,238,848	26,676,674	17,960,235
Pennsylvania Electric Co	2008	1,445,064,834	166,519,282	562,516,074	77,006,911	854,758,391	876,006,045	126,959,619	52,213,199	24,517,707	27,257,818
Pennsylvania Electric Co	2009	1,520,414,221	170,655,248	583,977,423	82,038,750	884,331,998	886,607,867	91,606,782	41,267,212	21,734,329	31,764,717
Pennsylvania Electric Co	2010	1,589,334,019	174,876,239	606,354,506	86,055,631	914,946,953	1,008,099,117	137,163,578	32,959,775	19,242,692	38,587,969
Pennsylvania Electric Co	2011	1,818,931,852	177,967,004	651,372,027	82,844,011	959,843,619	540,785,543	10,234,371	35,953,693	19,903,600	52,719,639

Schedule 2: Electric Utility Data Base

A	B	J	K	L	M	N	O	P	Q	R	S
Formula:		G+H+I-K-L-M									
Utility Name	Year	Net Plant less production	Accumulated Depreciation- Transmission	Accumulated Depreciation- Distribution	Accumulated Depreciation- General	Accumulated Depreciation- Total Utility Plant	O&M- Production Expense	O&M- Transmission Expense	O&M- Distribution Expense	O&M- Customer Account Expenses	O&M- Customer Service and Information Expenses
Pennsylvania Power Co	2007	241,772,717	6,317,235	132,088,158	4,877,734	143,283,127	200,639,506	3,202,648	14,401,114	7,178,013	2,332,320
Pennsylvania Power Co	2008	271,746,951	6,423,315	135,964,154	5,526,659	147,914,128	182,566,339	301,465	17,614,376	7,449,359	6,634,538
Pennsylvania Power Co	2009	290,222,373	6,542,788	140,757,755	5,791,881	153,092,424	163,034,875	375,644	8,393,165	6,761,869	10,910,888
Pennsylvania Power Co	2010	305,384,661	6,512,531	144,906,250	5,880,926	157,299,707	144,642,236	430,354	8,076,725	5,949,137	13,756,060
Pennsylvania Power Co	2011	335,330,829	6,568,438	153,534,758	6,914,349	167,017,545	112,642,119	5,589,978	7,916,894	5,895,341	17,348,021
Potomac Edison Co (The)	2007	1,021,272,167	176,290,232	541,314,164	29,270,542	746,874,938	645,024,259	14,497,084	35,974,596	11,935,794	1,335,880
Potomac Edison Co (The)	2008	1,078,502,568	184,196,873	572,578,793	31,784,177	788,559,843	708,226,274	14,275,644	36,737,699	12,935,139	2,314,268
Potomac Edison Co (The)	2009	1,109,990,152	193,551,662	608,987,234	34,020,544	836,559,440	783,863,470	9,940,377	34,514,618	15,823,866	4,223,469
Potomac Edison Co (The)	2010	936,113,158	197,627,283	495,580,548	30,564,903	723,772,734	726,900,870	11,141,812	30,571,502	13,429,873	6,974,949
Potomac Edison Co (The)	2011	963,172,662	205,274,353	525,124,451	27,093,275	757,492,079	598,729,692	10,752,337	25,214,835	9,662,055	13,345,983
PPL Electric Utilities Corp	2007	3,140,536,210	468,600,364	1,319,611,455	0	1,931,612,246	2,016,111,995	178,957,253	148,145,878	55,056,845	16,876,770
PPL Electric Utilities Corp	2008	3,157,790,421	479,905,629	1,363,887,475	157,261,949	2,001,055,053	1,986,351,927	178,070,434	147,160,410	61,463,379	19,991,446
PPL Electric Utilities Corp	2009	3,259,087,039	494,865,329	1,412,736,495	173,737,442	2,081,339,266	1,914,122,869	169,611,401	126,151,294	62,688,400	27,017,187
PPL Electric Utilities Corp	2010	3,466,469,051	506,375,952	1,463,780,862	186,621,377	2,156,778,191	1,391,924,776	112,323,875	142,377,661	70,552,848	84,025,123
PPL Electric Utilities Corp	2011	3,725,548,373	513,552,051	1,517,968,556	200,304,858	2,231,825,465	763,149,201	97,373,800	152,304,415	73,845,535	113,834,151
Progress Energy Carolinas	2007	3,608,343,567	568,469,648	1,643,045,545	154,752,508	7,810,843,848	2,217,124,764	56,756,057	111,899,793	46,350,745	5,990,975
Progress Energy Carolinas	2008	3,675,367,884	591,697,733	1,816,247,857	173,457,551	8,137,092,155	2,227,195,824	58,347,783	105,567,384	45,175,352	11,000,984
Progress Energy Carolinas	2009	3,731,917,888	623,423,899	1,991,235,844	177,782,341	8,447,354,123	2,474,806,958	59,134,415	118,393,659	47,763,947	20,238,096
Progress Energy Carolinas	2010	3,811,613,099	652,619,559	2,166,768,833	183,608,339	8,725,982,406	2,612,581,532	62,721,986	115,565,059	42,629,537	41,926,601
Progress Energy Carolinas	2011	4,025,957,510	685,105,221	2,334,001,299	180,067,229	8,974,013,091	2,299,349,426	74,415,365	144,204,871	41,920,277	46,612,054
Progress Energy Florida	2007	3,352,294,431	467,787,323	1,314,366,808	96,782,843	4,421,851,627	2,809,853,549	36,029,020	145,198,814	51,048,997	72,297,731
Progress Energy Florida	2008	3,573,357,374	475,762,867	1,400,066,245	128,973,740	4,562,794,903	3,161,022,483	37,628,730	143,360,373	49,943,267	71,494,001
Progress Energy Florida	2009	3,866,625,650	487,291,520	1,509,513,184	111,452,527	4,634,764,465	2,958,287,482	35,981,541	131,516,225	54,833,333	76,889,404
Progress Energy Florida	2010	4,092,175,943	503,368,837	1,565,989,569	107,187,909	4,791,009,765	3,116,971,510	35,138,825	142,363,908	48,889,015	94,709,136
Progress Energy Florida	2011	4,262,491,854	525,044,666	1,641,233,873	77,173,247	4,933,005,607	2,761,156,611	40,035,746	132,540,210	42,196,453	100,551,245
Public Service Co of Colorado	2007	2,956,407,292	290,251,596	881,872,704	23,058,206	2,403,026,069	1,727,189,637	34,707,804	80,707,030	40,316,855	21,237,603
Public Service Co of Colorado	2008	3,180,972,804	299,962,532	910,652,476	26,076,632	2,500,598,487	2,034,637,399	38,867,774	72,171,124	41,370,492	36,306,281
Public Service Co of Colorado	2009	3,402,767,425	315,820,339	958,553,867	26,871,566	2,640,231,893	1,588,482,620	40,702,540	76,186,877	37,330,425	93,964,056
Public Service Co of Colorado	2010	3,607,916,073	336,405,666	1,012,767,960	33,014,584	2,862,517,936	1,749,592,938	43,098,457	90,306,803	41,054,949	113,001,991
Public Service Co of Colorado	2011	3,796,327,380	350,977,603	1,068,967,010	47,697,878	3,025,375,540	1,675,251,633	51,360,767	96,761,823	41,045,405	101,593,214
Public Service Co of New Mexico	2007	871,639,707	219,942,085	402,428,328	38,903,186	1,323,743,895	843,694,683	34,201,126	26,146,782	13,373,234	2,541,992
Public Service Co of New Mexico	2008	915,091,272	228,806,427	422,771,241	43,460,317	1,372,524,250	819,947,541	37,581,747	23,593,615	15,677,636	2,114,716
Public Service Co of New Mexico	2009	943,653,713	237,480,645	443,872,432	72,054,491	1,444,100,683	572,865,177	36,392,451	25,822,814	11,514,079	1,507,100
Public Service Co of New Mexico	2010	1,004,171,331	245,174,730	462,254,131	65,370,121	1,449,001,619	555,572,466	35,437,136	25,588,120	13,072,646	1,342,842
Public Service Co of New Mexico	2011	1,033,832,219	253,837,396	482,915,302	69,995,453	1,498,023,537	555,380,521	36,735,987	24,446,700	15,434,936	1,166,632
Public Service Co of Oklahoma	2007	1,362,212,125	200,766,326	408,467,830	100,455,024	1,404,580,898	980,133,562	27,081,834	150,733,020	24,539,048	3,319,560
Public Service Co of Oklahoma	2008	1,527,883,341	201,892,517	427,875,951	96,644,793	1,422,580,851	1,199,417,325	37,660,249	2,836,751	23,149,211	4,960,130
Public Service Co of Oklahoma	2009	1,622,274,069	201,175,326	455,790,252	80,447,150	1,446,566,669	585,657,399	37,021,457	78,524,592	21,483,065	6,956,734
Public Service Co of Oklahoma	2010	1,739,731,305	200,363,602	473,777,914	82,944,549	1,482,943,949	695,882,212	40,068,345	90,675,723	20,361,287	15,984,776
Public Service Co of Oklahoma	2011	1,814,026,982	211,335,183	491,149,210	80,630,427	1,501,167,713	750,581,009	40,774,072	78,703,770	20,929,624	23,052,767
Public Service Electric & Gas Co	2007	4,709,703,463	664,044,781	1,582,531,027	124,501,042	2,371,076,850	3,343,683,890	47,146,269	158,629,646	158,720,928	134,876,290
Public Service Electric & Gas Co	2008	4,973,386,671	698,063,391	1,674,299,060	132,890,580	2,505,253,031	3,774,938,291	46,333,947	163,697,101	201,540,660	130,601,576
Public Service Electric & Gas Co	2009	5,389,129,883	715,175,363	1,708,303,868	117,201,295	2,540,680,526	3,295,200,633	53,433,494	161,065,497	243,836,192	147,707,687
Public Service Electric & Gas Co	2010	5,954,130,272	746,312,922	1,773,890,263	97,004,700	2,620,847,219	3,072,622,349	52,764,208	147,024,564	241,061,903	163,956,680
Public Service Electric & Gas Co	2011	6,461,564,333	748,093,928	1,866,467,223	102,384,065	2,735,581,714	2,675,648,562	55,958,611	148,115,188	241,509,119	145,303,182
San Diego Gas & Electric Co	2007	3,247,145,917	438,396,717	1,609,151,696	61,633,409	3,412,983,105	820,997,577	124,209,959	119,393,307	54,518,134	120,550,102
San Diego Gas & Electric Co	2008	3,489,104,280	459,284,152	1,678,866,330	67,200,854	3,530,401,256	1,095,003,515	112,238,785	119,420,861	53,738,140	160,367,000
San Diego Gas & Electric Co	2009	3,736,759,566	482,269,570	1,772,051,811	72,761,585	3,681,936,019	931,380,902	85,844,441	145,443,275	57,424,294	153,405,804
San Diego Gas & Electric Co	2010	4,034,470,076	504,398,361	1,800,353,386	79,957,141	3,803,072,301	988,676,413	92,117,879	109,413,498	59,250,249	128,639,169
San Diego Gas & Electric Co	2011	4,343,982,411	534,303,802	1,895,931,153	0	4,080,510,704	1,461,796,977	61,402,044	127,596,494	57,097,798	154,668,180
South Carolina Electric & Gas Co	2007	2,064,114,511	215,525,792	695,797,201	53,183,527	2,447,580,598	911,463,584	16,033,971	48,992,662	37,252,993	4,081,235
South Carolina Electric & Gas Co	2008	2,238,365,112	227,859,562	730,408,324	52,601,540	2,583,292,958	1,116,087,858	17,014,169	45,264,468	46,845,462	4,149,612
South Carolina Electric & Gas Co	2009	2,431,400,083	240,259,670	761,411,873	60,228,884	2,725,564,372	1,046,581,930	18,454,282	47,853,525	48,164,015	3,885,820
South Carolina Electric & Gas Co	2010	2,539,750,919	256,224,998	801,289,508	68,303,060	2,882,218,564	1,196,356,766	16,468,925	48,292,023	49,529,298	3,595,413
South Carolina Electric & Gas Co	2011	2,661,634,050	270,583,037	840,836,611	77,886,601	3,059,680,595	1,188,405,699	15,388,466	49,839,005	48,591,513	3,847,652
Southern California Edison Co	2007	11,933,717,789	1,504,518,845	4,181,118,601	727,148,369	13,267,176,028	4,921,498,335	283,847,135	380,092,467	200,685,583	468,921,587
Southern California Edison Co	2008	12,212,177,119	1,605,669,881	4,505,989,448	735,423,354	13,742,735,155	6,490,778,725	273,895,777	345,981,286	207,393,584	531,068,178
Southern California Edison Co	2009	13,740,897,397	1,556,978,009	4,810,488,247	723,964,733	14,162,546,610	3,649,647,009	238,531,695	416,993,748	207,919,411	489,390,954
Southern California Edison Co	2010	14,996,398,612	1,646,552,360	5,117,953,970	732,673,416	14,555,427,451	3,886,595,044	252,123,269	455,932,038	212,978,826	595,999,680
Southern California Edison Co	2011	16,310,496,796	1,689,618,275	5,368,101,408	802,468,093	14,967,373,402	4,789,608,198	235,054,669	485,876,026	223,329,570	676,619,254
Southern Indiana Gas & Electric Co	2007	393,573,461	83,541,430	160,772,220	14,207,077	819,014,826	238,037,433	3,751,863	9,584,084	6,357,762	620,991
Southern Indiana Gas & Electric Co	2008	427,639,808	81,934,431	172,321,528	15,386,042	862,231,147	258,753,479	9,064,103	15,835,333	6,590,635	647,703
Southern Indiana Gas & Electric Co	2009	503,243,577	86,890,770	182,265,137	16,617,172	910,898,358	255,214,510	10,389,632	16,359,130	7,247,629	875,000
Southern Indiana Gas & Electric Co	2010	579,789,550	92,807,970	194,421,668	16,939,555	967,124,742	296,509,407	13,596,805	15,699,210	7,382,433	614,436
Southern Indiana Gas & Electric Co	2011	591,060,346	99,096,402	206,826,619	17,823,521	1,021,405,566	313,410,796	13,879,289	16,208,824	7,246,114	641,411
Southwestern Electric Power Co	2007	1,408,467,562	287,884,119	515,736,164	118,171,653	2,000,153,028	936,298,059	31,300,352	52,226,986	25,618,506	4,580,147
Southwestern Electric Power Co	2008	1,514,549,249	302,123,844	535,832,199	126,507,560	2,071,163,429	1,025,148,518	31,136,141	62,438,388	23,977,441	6,770,479
Southwestern Electric Power Co	2009	1,593,841,193	330,381,920	552,879,858	131,772,223	2,165,296,703	766,918,604	29,627,119	48,951,975	22,948,215	6,923,394
Southwestern Electric Power Co	2010	1,741,221,770	356,345,144	614,063,284	143,892,811	2,309,540,025	873,467,279	33,997,837	67,371,131	22,070,015	8,712,720
Southwestern Electric Power Co	2011	1,808,991,149	370,861,968	637,961,404	153,582,765	2,390,622,266	949,303,880	33,846,469	74,273,938	24,366,494	10,337,691
Southwestern Public Service Co	2007	1,199,503,926	234,532,357	290,648,306	85,146,983	1,565,933,232	1,275,262,707	45,943,329	26,707,880	17,323,356	6,308,528
Southwestern Public Service Co	2008	1,266,388,405	245,751,593	299,576,837	77,456,149	1,602,590,423	1,591,683,149	46,962,914	28,224,086	18,506,214	12,066,974
Southwestern Public Service Co	2009	1,392,552,728	258,353,002	311,966,719	72,893,155	1,649,308,947	969,373,258	54,254,803	30,315,802	16,416,941	12,107,721
Southwestern Public Service Co	2010	1,407,200,998	266,390,023	281,396,304	83,776,477	1,670,031,167	1,076,785,517	65,346,761	31,295,953	18,012,580	15,258,525
Southwestern Public Service Co	2011	1,590,088,644	276,449,062	288,861,231	92,007,355	1,702,756,061	1,128,492,594	81,909,742	37,858,822	15,724,340	18,878,499

Schedule 2: Electric Utility Data Base

A	B	J	K	L	M	N	O	P	Q	R	S
Formula:		G+H+I-K-L-M									
Utility Name	Year	Net Plant less production	Accumulated Depreciation- Transmission	Accumulated Depreciation- Distribution	Accumulated Depreciation- General	Accumulated Depreciation- Total Utility Plant	O&M- Production Expense	O&M- Transmission Expense	O&M- Distribution Expense	O&M- Customer Account Expenses	O&M- Customer Service and Information Expenses
Tampa Electric Co	2007	1,384,818,278	149,237,034	631,719,828	73,513,667	1,964,773,800	1,254,835,989	11,769,848	47,280,303	29,005,200	14,448,043
Tampa Electric Co	2008	1,462,314,661	158,689,099	662,507,720	72,305,815	2,003,045,163	1,363,039,248	12,757,908	48,206,075	30,388,145	17,883,654
Tampa Electric Co	2009	1,539,014,429	165,946,654	698,821,929	82,031,305	2,094,408,780	1,161,561,800	14,341,817	47,389,284	29,876,136	33,018,024
Tampa Electric Co	2010	1,596,059,716	166,840,279	719,789,224	88,991,308	2,179,908,621	1,079,989,035	13,046,201	44,573,288	31,227,195	43,799,263
Tampa Electric Co	2011	1,648,439,580	172,738,589	741,778,937	96,006,373	2,277,136,125	995,224,473	13,141,531	44,114,198	24,837,487	43,479,301
Toledo Edison Co (The)	2007	411,632,362	8,651,271	354,863,746	27,965,251	393,464,151	514,304,643	67,409,177	25,560,149	15,713,487	2,962,137
Toledo Edison Co (The)	2008	439,380,640	8,863,133	375,299,351	30,244,321	415,234,510	468,346,487	74,487,751	25,316,833	13,727,297	3,132,293
Toledo Edison Co (The)	2009	492,585,062	9,106,370	391,996,234	0	433,332,743	578,297,268	18,223,917	20,205,512	15,532,464	1,338,771
Toledo Edison Co (The)	2010	474,536,134	9,625,443	409,252,285	33,108,516	451,986,244	291,807,533	1,865,483	17,254,541	9,914,245	1,524,447
Toledo Edison Co (The)	2011	502,077,012	10,060,250	427,387,263	35,159,196	472,606,709	223,414,815	20,140,885	21,840,519	9,843,304	2,872,955
Tucson Electric Power Co	2007	841,441,138	380,891,530	434,206,539	70,744,660	1,461,219,937	698,831,108	17,502,599	17,866,462	17,504,810	2,316,221
Tucson Electric Power Co	2008	938,750,070	401,728,454	468,209,225	68,801,301	1,529,101,754	784,525,154	19,284,865	17,711,821	19,228,162	3,613,713
Tucson Electric Power Co	2009	976,327,633	429,905,334	491,567,394	72,168,028	1,590,195,041	645,063,230	15,916,563	17,943,624	19,030,294	8,564,114
Tucson Electric Power Co	2010	1,036,195,651	435,094,891	511,156,067	77,694,233	1,756,614,734	658,686,913	17,313,539	18,885,975	19,033,968	10,778,525
Tucson Electric Power Co	2011	1,276,904,089	415,736,578	523,618,000	84,944,024	1,777,932,435	676,442,184	12,803,479	19,239,563	17,127,264	13,181,398
Unitil Energy Systems	2007	114,199,505	0	57,265,033	4,349,247	61,614,280	107,214,969	9,615,400	3,615,550	3,473,904	2,263,687
Unitil Energy Systems	2008	127,320,624	0	53,880,046	4,488,840	58,368,886	108,401,478	14,444,054	3,823,976	3,492,393	1,605,977
Unitil Energy Systems	2009	135,385,693	0	58,222,067	4,891,956	63,114,023	92,466,215	15,677,227	3,783,297	3,249,512	1,631,001
Unitil Energy Systems	2010	144,335,441	0	61,904,658	6,010,283	67,914,941	75,729,821	20,173,084	4,358,529	3,360,153	3,477,583
Unitil Energy Systems	2011	148,181,159	0	65,935,542	6,535,540	72,471,082	61,180,812	16,797,774	5,936,385	3,834,666	2,504,665
UNS Electric Inc	2007	140,142,379	32,782,582	205,281,264	13,661,264	262,571,712	113,756,133	7,701,404	5,803,957	5,035,619	334,207
UNS Electric Inc	2008	152,802,813	33,369,111	213,339,814	13,138,754	271,469,120	136,734,952	8,348,774	5,999,655	5,421,624	769,203
UNS Electric Inc	2009	163,704,860	34,880,709	224,428,331	14,487,605	285,889,894	124,350,750	7,857,136	5,216,862	4,505,372	2,079,550
UNS Electric Inc	2010	166,453,453	36,476,031	235,367,853	16,297,028	300,324,401	148,036,840	7,514,943	5,797,240	4,649,011	2,159,046
UNS Electric Inc	2011	186,183,678	38,584,019	245,698,714	16,866,726	319,054,313	138,135,457	10,517,497	5,396,288	4,034,533	2,226,324
Virginia Electric & Power Co	2007	5,664,068,837	781,818,342	2,647,356,440	271,235,978	8,398,358,238	3,568,818,449	55,310,465	179,201,700	64,521,674	2,277,019
Virginia Electric & Power Co	2008	6,003,848,337	799,076,796	2,781,787,722	282,758,546	8,727,086,897	3,864,539,200	45,783,788	198,589,571	66,031,784	14,055,300
Virginia Electric & Power Co	2009	6,565,380,977	815,768,084	2,935,401,937	292,405,887	9,158,133,026	4,080,795,653	167,814,848	187,890,243	90,104,248	2,037,559
Virginia Electric & Power Co	2010	7,271,161,251	819,846,680	3,110,239,350	298,118,113	9,576,015,740	3,630,188,141	90,940,618	202,856,413	71,491,765	19,521,589
Virginia Electric & Power Co	2011	8,183,577,814	861,442,817	3,281,893,484	310,863,482	10,199,755,958	3,545,198,061	117,764,856	249,113,170	73,868,742	18,449,975
West Penn Power Co	2007	1,016,391,863	170,844,821	543,213,898	58,853,828	772,912,547	823,227,237	50,516,223	44,631,001	24,578,721	4,300,334
West Penn Power Co	2008	1,137,510,235	177,221,823	570,220,149	62,867,961	810,309,933	868,801,767	50,766,895	45,555,001	24,826,468	4,284,362
West Penn Power Co	2009	1,153,020,842	180,651,026	603,525,499	66,158,075	850,334,600	918,476,695	49,387,770	40,755,371	20,470,101	10,018,162
West Penn Power Co	2010	1,183,073,803	186,619,534	628,359,200	72,130,211	887,108,945	1,076,314,576	54,742,062	56,826,596	25,267,224	13,079,203
West Penn Power Co	2011	1,318,176,615	192,542,877	658,620,781	0	926,642,861	694,853,553	30,797,991	38,585,348	22,346,366	31,031,173
Westar Energy Inc	2007	848,009,152	156,214,454	313,364,751	84,006,266	1,323,765,386	467,570,673	60,430,971	40,382,517	10,995,438	866,965
Westar Energy Inc	2008	947,127,867	166,273,849	328,289,362	92,739,118	1,370,586,162	545,376,902	53,168,149	41,425,340	12,431,231	2,442,998
Westar Energy Inc	2009	1,056,036,282	174,283,888	340,680,941	90,806,012	1,433,735,369	475,207,550	67,017,246	46,690,010	13,690,958	1,879,814
Westar Energy Inc	2010	1,228,798,824	183,742,720	355,095,510	96,569,170	1,538,583,517	495,847,584	73,406,990	48,642,607	13,779,186	1,933,133
Westar Energy Inc	2011	1,288,018,458	205,931,267	370,340,149	86,938,910	1,626,797,286	490,308,955	79,230,934	49,024,500	14,294,232	2,089,497
Wheeling Power Co	2007	79,291,567	17,392,878	32,165,805	2,165,674	51,724,357	42,440,084	799,456	4,815,138	2,027,052	298,039
Wheeling Power Co	2008	85,613,847	17,452,691	33,778,935	2,208,046	53,439,672	49,218,270	690,127	5,769,126	1,968,482	262,398
Wheeling Power Co	2009	94,181,968	17,185,954	34,596,305	2,326,334	54,108,593	55,072,748	579,641	4,850,776	1,693,945	269,604
Wheeling Power Co	2010	94,916,334	18,123,210	36,727,450	2,477,144	57,327,804	74,134,467	1,027,800	9,322,059	1,711,639	222,858
Wheeling Power Co	2011	114,401,227	19,149,860	39,321,627	2,523,251	60,994,738	83,971,259	953,381	5,012,448	1,776,512	418,821
Wisconsin Electric Power Co	2007	2,074,217,748	-394,617	1,116,295,006	44,552,010	2,391,204,779	1,467,330,523	173,766,729	73,136,650	38,456,029	40,300,524
Wisconsin Electric Power Co	2008	2,139,158,581	-408,632	1,172,852,631	45,991,009	2,535,074,404	1,781,932,592	249,541,065	91,488,259	93,665,872	52,135,860
Wisconsin Electric Power Co	2009	2,173,973,616	-422,647	1,234,205,339	45,811,918	2,625,037,292	1,572,702,602	257,780,460	81,737,980	50,090,395	51,827,703
Wisconsin Electric Power Co	2010	2,195,119,085	-422,647	1,279,603,295	42,836,971	2,720,197,012	1,702,949,584	266,546,145	89,884,165	73,888,812	59,183,067
Wisconsin Electric Power Co	2011	2,217,640,475	-450,677	1,334,062,788	40,463,243	2,781,425,690	1,777,700,246	271,469,229	94,070,178	74,368,314	58,126,386
Wisconsin Power & Light Co	2007	899,150,930	0	428,218,677	17,841,140	970,997,613	676,191,205	83,492,795	25,543,023	13,924,403	34,533,861
Wisconsin Power & Light Co	2008	974,207,477	0	457,269,333	21,523,671	1,022,035,010	688,327,019	95,649,123	22,134,597	14,160,267	34,711,726
Wisconsin Power & Light Co	2009	1,090,509,799	0	460,149,522	25,312,180	1,019,652,014	677,986,677	96,478,352	19,413,395	14,242,869	31,144,859
Wisconsin Power & Light Co	2010	1,172,831,888	0	476,037,416	26,022,573	1,064,797,588	623,474,951	102,564,715	25,712,284	11,555,910	35,301,470
Wisconsin Power & Light Co	2011	1,235,174,948	0	502,351,834	29,702,549	1,180,358,111	576,837,729	106,974,897	23,980,501	10,916,108	38,236,682
Wisconsin Public Service Corp	2007	520,773,706	0	367,877,021	16,659,569	911,738,858	684,648,601	81,383,447	44,840,486	16,827,358	23,024,388
Wisconsin Public Service Corp	2008	531,833,132	0	387,719,471	17,452,173	950,553,556	688,326,580	94,075,016	43,363,465	16,101,401	20,163,916
Wisconsin Public Service Corp	2009	527,203,494	0	409,360,576	18,266,790	1,006,992,304	621,112,963	96,339,264	42,743,813	18,179,186	18,004,238
Wisconsin Public Service Corp	2010	521,323,638	0	432,155,433	18,963,063	1,071,556,950	601,335,474	109,749,750	44,928,173	16,454,852	29,903,804
Wisconsin Public Service Corp	2011	526,127,832	0	446,336,932	19,514,395	1,132,077,267	621,918,765	111,946,390	45,022,993	17,274,770	33,567,399

Schedule 2: Electric Utility Data Base

A	B	T	U	V	W	X	Y	Z	AA
Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
ALLETE Inc	2007	41,111,527	159,065	530,392,721	100,418,502	0.38	1,994	6,341	9,263
ALLETE Inc	2008	69,832,647	68,934	494,992,887	132,539,514	0.42	2,016	6,205	9,853
ALLETE Inc	2009	46,539,368	263,951	472,248,329	111,810,832	0.39	2,479	6,196	9,593
ALLETE Inc	2010	55,006,756	351,595	566,647,250	145,725,486	0.38	2,530	6,080	10,776
ALLETE Inc	2011	60,219,332	86,530	550,538,461	149,453,855	0.36	2,555	6,187	10,804
Ameren Missouri	2007	258,635,996	1,123,956	1,676,530,549	541,852,436	0.33	2,580	32,489	44,427
Ameren Missouri	2008	265,661,456	1,145,670	1,697,889,710	533,913,229	0.34	2,591	32,956	45,098
Ameren Missouri	2009	245,399,543	531,605	1,601,710,209	555,436,568	0.33	2,589	33,012	45,834
Ameren Missouri	2010	235,269,294	259,263	1,696,695,123	530,352,071	0.28	2,591	33,031	46,325
Ameren Missouri	2011	270,552,242	233,795	1,877,797,974	584,526,959	0.30	2,627	33,256	37,154
Appalachian Power Co	2007	109,102,191	110	2,071,337,753	286,410,784	0.32	6,423	45,410	42,181
Appalachian Power Co	2008	113,936,041	0	2,317,275,308	303,052,452	0.31	6,437	45,585	40,793
Appalachian Power Co	2009	121,091,362	836	2,224,377,255	328,019,746	0.31	6,443	45,708	40,739
Appalachian Power Co	2010	125,907,973	426	2,588,872,600	328,483,085	0.30	6,454	45,779	40,737
Appalachian Power Co	2011	112,971,842	78	2,439,785,199	304,441,905	0.28	6,495	45,817	41,207
Arizona Public Service Co	2007	141,041,012	14,202,647	2,015,634,653	389,170,769	0.26	5,778	28,681	38,732
Arizona Public Service Co	2008	147,838,860	15,162,546	2,205,876,050	412,536,537	0.28	5,759	28,022	36,281
Arizona Public Service Co	2009	158,383,410	8,563,206	2,093,153,955	417,374,727	0.27	5,806	28,670	37,582
Arizona Public Service Co	2010	183,332,702	9,224,527	1,986,392,246	455,712,985	0.27	5,887	28,515	38,273
Arizona Public Service Co	2011	172,533,521	8,828,967	1,961,707,828	485,955,819	0.27	5,892	28,937	39,592
Avista Corp	2007	48,205,079	949,730	504,795,844	124,939,132	0.34	2,153	17,800	6,172
Avista Corp	2008	47,675,458	766,527	665,007,310	134,198,389	0.34	2,218	18,100	6,007
Avista Corp	2009	52,340,643	928,503	663,266,859	151,035,682	0.34	2,219	17,800	6,217
Avista Corp	2010	62,130,350	197,423	763,521,770	167,497,980	0.35	2,210	18,200	6,179
Avista Corp	2011	59,599,180	8,327	750,210,435	170,986,157	0.36	2,210	18,300	6,153
Baltimore Gas & Electric Co	2007	159,544,979	0	1,867,446,322	367,065,753	0.38	916	24,000	31,631
Baltimore Gas & Electric Co	2008	137,691,621	0	2,255,829,179	375,723,879	0.47	916	24,500	32,570
Baltimore Gas & Electric Co	2009	148,458,562	0	2,230,185,545	389,315,168	0.40	939	24,500	38,675
Baltimore Gas & Electric Co	2010	156,818,753	0	2,119,606,453	438,662,394	0.41	970	24,800	35,437
Baltimore Gas & Electric Co	2011	167,597,623	0	1,678,344,851	493,750,753	0.43	913	24,800	37,894
CenterPoint Energy Houston Electric LLC	2007	170,693,979	0	669,220,177	669,220,177	0.43	3,806	46,376	50,586
CenterPoint Energy Houston Electric LLC	2008	164,923,484	0	717,347,321	717,347,321	0.45	3,782	47,293	51,100
CenterPoint Energy Houston Electric LLC	2009	156,965,566	0	765,061,934	765,061,934	0.46	3,787	47,806	51,247
CenterPoint Energy Houston Electric LLC	2010	163,096,049	0	824,202,595	824,202,595	0.46	3,787	48,232	52,552
CenterPoint Energy Houston Electric LLC	2011	182,488,036	0	888,531,529	888,531,529	0.47	3,812	48,733	52,422
Central Hudson Gas & Electric Corp	2007	56,913,951	959,181	510,766,394	126,740,307	0.54	629	9,326	4,377
Central Hudson Gas & Electric Corp	2008	57,356,498	303,320	501,801,006	135,999,855	0.56	629	9,449	4,872
Central Hudson Gas & Electric Corp	2009	68,801,398	304,342	419,721,810	158,358,295	0.58	629	9,500	4,512
Central Hudson Gas & Electric Corp	2010	87,556,366	351,964	430,155,810	183,455,899	0.58	629	9,600	4,620
Central Hudson Gas & Electric Corp	2011	78,239,766	348,067	399,783,785	193,385,985	0.58	629	8,700	4,614
Central Vermont Public Service Corp	2007	37,823,396	3,558	279,225,717	104,364,959	0.68	627	8,806	1,059
Central Vermont Public Service Corp	2008	38,609,674	7,883	290,500,263	110,136,626	0.68	627	8,915	1,102
Central Vermont Public Service Corp	2009	36,358,141	0	284,825,992	113,290,315	0.67	627	8,936	1,102
Central Vermont Public Service Corp	2010	38,011,929	0	283,087,848	108,211,697	0.66	626	8,964	1,137
Central Vermont Public Service Corp	2011	38,124,026	0	304,059,520	131,835,332	0.71	631	9,017	1,138
Chugach Electric Association Inc	2007	20,011,267	0	202,308,145	46,164,866	0.46	556	1,673	4,076
Chugach Electric Association Inc	2008	18,373,886	0	228,793,603	42,693,652	0.42	557	1,684	4,143
Chugach Electric Association Inc	2009	17,580,740	0	230,467,284	41,953,136	0.41	563	1,685	4,143

Schedule 2: Electric Utility Data Base

A	B	T	U	V	W	X	Y	Z	AA
Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
Chugach Electric Association Inc	2010	19,649,319	0	200,344,350	43,684,779	0.43	562	1,693	4,143
Chugach Electric Association Inc	2011	19,619,501	0	228,085,556	46,191,097	0.45	562	1,688	4,143
CLECO Power LLC	2007	43,468,337	3,593,585	803,224,229	113,858,034	0.34	1,239	11,408	11,895
CLECO Power LLC	2008	39,508,931	3,501,171	843,243,664	107,558,901	0.32	1,240	11,489	12,063
CLECO Power LLC	2009	44,590,547	3,406,327	625,099,244	110,352,990	0.34	1,240	11,571	12,095
CLECO Power LLC	2010	46,447,606	3,820,253	689,343,366	120,347,447	0.22	1,266	11,649	12,121
CLECO Power LLC	2011	48,817,963	4,083,039	645,223,288	125,517,955	0.22	1,299	11,720	13,555
Cleveland Electric Illuminating Co (The)	2007	50,045,416	1,592,746	1,063,429,654	261,740,037	0.26	2,144	33,084	7,841
Cleveland Electric Illuminating Co (The)	2008	33,562,249	1,630,946	1,034,607,417	257,281,614	0.25	2,144	33,126	7,830
Cleveland Electric Illuminating Co (The)	2009	58,400,821	954,862	1,144,933,029	157,031,180	0.23	2,144	33,168	9,720
Cleveland Electric Illuminating Co (The)	2010	39,248,903	1,088,158	610,321,800	119,736,005	0.16	2,144	33,210	9,670
Cleveland Electric Illuminating Co (The)	2011	44,958,593	1,198,338	383,005,482	146,584,443	0.23	2,114	33,252	9,778
Commonwealth Edison Co	2007	389,690,083	0	4,845,629,224	1,253,857,159	0.50	5,519	78,661	77,673
Commonwealth Edison Co	2008	326,880,211	0	4,662,634,223	1,401,966,829	0.49	5,547	81,253	79,693
Commonwealth Edison Co	2009	391,270,374	0	4,173,068,358	1,417,988,111	0.47	4,875	64,637	79,635
Commonwealth Edison Co	2010	374,912,913	0	4,416,194,728	1,419,664,883	0.44	4,875	65,852	79,725
Commonwealth Edison Co	2011	380,611,717	0	4,345,074,908	1,523,326,544	0.46	4,879	65,977	80,724
Consolidated Edison Co of New York Inc	2007	543,832,608	25,410,815	4,799,817,349	1,367,180,269	0.34	491	130,503	45,649
Consolidated Edison Co of New York Inc	2008	567,299,579	17,728,103	5,120,188,050	1,458,193,630	0.34	494	131,577	46,180
Consolidated Edison Co of New York Inc	2009	778,280,373	14,066,510	4,730,344,491	1,678,363,834	0.35	494	132,396	46,404
Consolidated Edison Co of New York Inc	2010	1,029,664,793	12,461,440	4,946,628,317	1,907,648,140	0.36	505	133,105	46,691
Consolidated Edison Co of New York Inc	2011	1,063,885,633	12,062,542	4,612,004,502	1,964,458,783	0.35	505	133,479	42,326
Consumers Energy Co	2007	164,165,939	385,515	2,478,504,501	526,111,188	0.36		70,059	23,286
Consumers Energy Co	2008	194,527,683	180,122	2,486,451,515	625,905,655	0.36		70,259	25,052
Consumers Energy Co	2009	202,282,387	83,934	2,352,029,435	697,390,759	0.38		70,462	20,897
Consumers Energy Co	2010	242,520,300	75,259	2,542,372,602	763,571,275	0.38		70,665	19,978
Consumers Energy Co	2011	177,258,217	222,958	2,644,142,738	788,684,811	0.39		70,739	20,699
Detroit Edison Co (The)	2007	523,233,442	1,818,731	3,051,354,469	1,250,707,292	0.44	89	45,720	33,444
Detroit Edison Co (The)	2008	425,071,326	2,488,972	3,071,165,076	1,179,335,580	0.43	85	45,525	33,502
Detroit Edison Co (The)	2009	400,873,656	1,343,966	2,746,769,561	1,144,040,529	0.40	66	45,732	33,337
Detroit Edison Co (The)	2010	403,545,218	1,108,788	2,919,194,232	1,216,159,807	0.39	0	45,864	33,433
Detroit Edison Co (The)	2011	414,569,683	1,580,790	3,095,707,159	1,230,051,537	0.40	0	46,248	33,557
Duke Energy Carolinas	2007	515,403,234	32,204	3,214,897,739	827,379,677	0.24	8,229	99,000	91,670
Duke Energy Carolinas	2008	504,145,108	5,795	3,527,762,676	832,517,514	0.26	8,239	100,000	92,272
Duke Energy Carolinas	2009	469,617,129	598,579	3,202,042,260	811,780,883	0.26	8,246	101,000	92,928
Duke Energy Carolinas	2010	632,515,099	1,140,235	3,832,615,654	1,008,008,953	0.28	8,260	101,700	92,963
Duke Energy Carolinas	2011	538,666,206	1,519,374	3,831,904,317	943,589,233	0.27	8,299	101,700	93,153
Duke Energy Indiana	2007	258,369,946	9,543,974	1,396,778,888	409,596,355	0.33	5,371	30,000	25,352
Duke Energy Indiana	2008	221,949,810	220,899	1,612,325,535	401,154,149	0.32	5,376	31,000	25,796
Duke Energy Indiana	2009	206,450,918	47,167	1,464,480,416	387,759,631	0.30	5,756	31,000	25,956
Duke Energy Indiana	2010	227,044,477	172,514	1,530,937,688	398,451,441	0.29	5,361	31,000	25,329
Duke Energy Indiana	2011	199,246,012	322,941	1,624,357,046	416,328,382	0.30	5,343	30,900	25,784
Duke Energy Ohio	2007	239,951,155	10,510	1,875,355,244	366,693,358	0.28	2,223	19,500	59,115
Duke Energy Ohio	2008	216,368,086	2,360	1,633,686,185	352,854,636	0.28	2,227	19,500	61,583
Duke Energy Ohio	2009	207,072,067	71,005	1,540,035,400	345,826,176	0.27	2,235	19,500	61,976
Duke Energy Ohio	2010	198,686,695	350,463	1,472,515,070	349,193,415	0.27	2,235	19,500	61,998
Duke Energy Ohio	2011	157,533,753	410,432	1,308,720,108	313,989,902	0.35	2,237	19,600	62,020
Empire District Electric Co (The)	2007	29,739,563	423,424	282,467,957	69,520,604	0.33	1,346	6,785	5,208

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Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
Empire District Electric Co (The)	2008	28,784,920	357,103	293,060,530	65,352,665	0.30	1,346	6,857	5,259
Empire District Electric Co (The)	2009	28,314,733	353,339	277,269,472	69,473,028	0.31	1,347	6,905	5,409
Empire District Electric Co (The)	2010	32,463,976	369,230	307,140,214	79,382,063	0.31	1,354	6,923	5,434
Empire District Electric Co (The)	2011	36,660,827	329,001	319,841,279	86,692,571	0.30	1,354	6,842	5,546
Fitchburg Gas & Electric Light Co	2007	4,251,134	56,898	55,344,397	11,617,167	0.49	25	737	1,252
Fitchburg Gas & Electric Light Co	2008	5,354,511	80,200	55,324,336	15,293,923	0.58	25	715	626
Fitchburg Gas & Electric Light Co	2009	6,500,366	242,357	53,035,143	17,886,879	0.63	25	715	626
Fitchburg Gas & Electric Light Co	2010	4,765,707	358,429	50,576,339	17,986,946	0.59	25	718	626
Fitchburg Gas & Electric Light Co	2011	5,225,477	498,916	46,904,168	19,541,327	0.61	38	482	623
Florida Power & Light Co	2007	328,198,159	17,524,686	8,230,483,474	916,310,200	0.21	6,633	66,751	130,112
Florida Power & Light Co	2008	195,997,372	16,278,393	8,180,519,831	815,352,575	0.19	6,727	66,630	132,619
Florida Power & Light Co	2009	322,454,706	8,949,043	7,712,019,474	899,071,831	0.19	6,726	66,922	136,502
Florida Power & Light Co	2010	312,539,654	9,513,562	6,584,661,252	947,659,485	0.20	6,721	67,358	137,472
Florida Power & Light Co	2011	343,250,779	14,370,793	6,660,249,857	1,027,637,445	0.21	6,721	67,446	137,468
Idaho Power Co	2007	97,638,808	0	600,557,914	211,845,580	0.44	4,690	64,672	13,573
Idaho Power Co	2008	105,274,854	0	649,816,334	229,620,011	0.43	4,738	65,045	13,733
Idaho Power Co	2009	103,967,400	0	708,405,619	242,875,551	0.42	4,751	26,675	14,139
Idaho Power Co	2010	103,771,676	0	693,221,250	252,642,430	0.43	4,758	26,698	17,572
Idaho Power Co	2011	138,584,798	0	709,101,987	280,828,435	0.47	4,770	26,714	17,713
Indiana Michigan Power Co	2007	118,853,586	1,135	1,452,821,197	202,510,138	0.27	4,071	17,965	26,651
Indiana Michigan Power Co	2008	116,461,594	2,437	1,625,028,815	206,783,726	0.29	4,076	17,947	26,676
Indiana Michigan Power Co	2009	126,019,761	3,458	1,479,141,433	212,629,871	0.26	4,079	17,930	27,109
Indiana Michigan Power Co	2010	139,505,781	4,335	1,662,695,761	257,289,384	0.34	4,081	17,924	27,021
Indiana Michigan Power Co	2011	124,745,684	122,383	1,621,815,263	255,737,199	0.34	4,060	17,945	27,522
Indianapolis Power & Light	2007	89,618,247	0	551,875,376	154,793,440	0.24	830	11,627	13,339
Indianapolis Power & Light	2008	95,105,273	0	614,485,083	170,671,756	0.27	827	11,103	13,399
Indianapolis Power & Light	2009	109,131,690	0	626,279,381	179,558,205	0.29	830	11,533	13,399
Indianapolis Power & Light	2010	101,107,633	0	692,971,881	173,322,319	0.28	839	11,504	13,539
Indianapolis Power & Light	2011	105,597,358	0	747,354,653	177,727,780	0.30	838	11,224	13,689
Interstate Power & Light Co	2007	79,011,368	0	862,277,771	190,479,148	0.29		22,326	4,100
Interstate Power & Light Co	2008	77,354,213	0	920,735,296	253,479,150	0.40		22,395	4,115
Interstate Power & Light Co	2009	80,273,756	4,253	969,298,342	298,991,231	0.45		22,400	4,375
Interstate Power & Light Co	2010	89,189,385	1,742	1,030,296,608	365,242,118	0.45		22,468	5,614
Interstate Power & Light Co	2011	85,836,427	0	1,055,649,679	398,316,266	0.52		22,478	5,735
Jersey Central Power & Light Co	2007	48,616,391	0	2,283,479,772	317,053,397	0.26	2,135	22,272	63,392
Jersey Central Power & Light Co	2008	20,168,290	0	2,508,574,252	297,575,410	0.25	2,160	22,404	65,660
Jersey Central Power & Light Co	2009	65,336,059	0	2,091,974,199	306,183,209	0.26	2,160	22,536	65,061
Jersey Central Power & Light Co	2010	75,599,246	0	2,070,058,966	329,433,207	0.27	2,160	22,668	68,567
Jersey Central Power & Light Co	2011	97,870,729	0	1,809,562,119	423,509,457	0.40	2,159	22,800	68,198
Kentucky Power Co	2007	20,244,314	23	469,420,910	65,800,789	0.32	1,267	9,692	6,955
Kentucky Power Co	2008	20,866,703	0	565,011,972	65,703,620	0.34	1,279	9,741	6,561
Kentucky Power Co	2009	22,500,883	77	520,683,138	62,826,848	0.32	1,279	9,765	6,706
Kentucky Power Co	2010	22,158,393	69	555,805,428	77,167,775	0.33	1,279	9,808	6,681
Kentucky Power Co	2011	18,614,164	14	572,532,448	87,439,522	0.34	1,282	9,831	6,976
Kingsport Power Co	2007	2,407,913	0	84,445,045	8,601,712	0.35	72	1,286	719
Kingsport Power Co	2008	2,210,800	0	101,561,975	9,331,825	0.42	72	1,286	719
Kingsport Power Co	2009	2,384,089	9	136,332,847	12,785,699	0.60	72	1,287	719
Kingsport Power Co	2010	2,365,229	4	131,585,661	7,751,630	0.25	72	1,286	719

Schedule 2: Electric Utility Data Base

A	B	T	U	V	W	X	Y	Z	AA
Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
Kingsport Power Co	2011	1,807,146	2	135,896,193	9,158,484	0.37	72	1,287	718
Madison Gas & Electric Co	2007	28,966,466	243,074	242,680,043	73,118,487	0.41		1,981	1,168
Madison Gas & Electric Co	2008	30,717,570	208,576	262,276,064	84,892,822	0.45		1,983	1,184
Madison Gas & Electric Co	2009	30,672,982	186,458	236,958,367	84,007,985	0.45		1,982	1,222
Madison Gas & Electric Co	2010	36,671,144	167,889	242,811,904	96,581,386	0.44		2,015	1,224
Madison Gas & Electric Co	2011	36,621,320	183,675	243,182,280	96,454,416	0.41		2,027	1,224
MDU Resources Group Inc	2007	17,165,805	299,088	130,914,986	41,070,316	0.41	3,055	4,500	3,899
MDU Resources Group Inc	2008	18,649,753	314,249	135,952,798	42,610,873	0.39	3,042	4,500	3,944
MDU Resources Group Inc	2009	16,195,039	273,396	124,872,243	39,765,822	0.37	3,046	4,600	3,988
MDU Resources Group Inc	2010	16,037,778	137,723	125,062,284	40,637,125	0.33	3,048	4,600	4,037
MDU Resources Group Inc	2011	18,668,599	216,637	132,390,607	44,301,561	0.33	3,048	4,600	4,272
Metropolitan Edison Co	2007	18,372,274	21,696	1,206,787,668	411,345,512	0.57	1,407	18,479	9,962
Metropolitan Edison Co	2008	8,099,715	28,205	1,326,270,553	425,409,872	0.57	1,422	18,533	10,353
Metropolitan Edison Co	2009	32,570,146	11,380	1,177,849,815	272,830,820	0.35	1,422	18,587	10,521
Metropolitan Edison Co	2010	40,473,992	11,337	1,367,614,054	408,581,743	0.48	1,422	18,641	10,558
Metropolitan Edison Co	2011	63,156,574	25,085	826,792,912	199,638,672	0.34	1,422	18,695	10,682
Monongahela Power Co	2007	76,869,977	63,944	741,818,593	139,185,655	0.42	1,678	21,544	14,128
Monongahela Power Co	2008	72,494,508	56,054	692,084,597	140,646,718	0.46	1,677	21,671	13,081
Monongahela Power Co	2009	74,734,498	1,780	709,024,999	154,274,931	0.47	1,677	23,490	13,655
Monongahela Power Co	2010	77,199,278	0	799,864,571	146,184,439	0.39	1,682	21,665	14,838
Monongahela Power Co	2011	99,568,416	0	1,009,446,019	263,414,592	0.53	1,682	20,730	18,274
Northern States Power Co (Minnesota)	2007	161,678,106	159,488	2,586,732,747	538,055,527	0.34	4,734	94,520	42,961
Northern States Power Co (Minnesota)	2008	181,064,450	152,452	2,623,355,224	567,328,212	0.35	4,756	95,410	43,211
Northern States Power Co (Minnesota)	2009	198,081,375	164,155	2,418,003,773	600,036,712	0.36	4,809	96,607	44,216
Northern States Power Co (Minnesota)	2010	212,334,415	92,646	2,686,064,302	648,425,074	0.38	4,790	96,754	45,202
Northern States Power Co (Minnesota)	2011	203,221,383	54,873	2,659,418,504	699,000,929	0.38	4,826	96,952	46,278
Northern States Power Co (Wisconsin)	2007	29,728,387	269,813	494,956,377	103,432,094	0.43	2,397	33,746	7,749
Northern States Power Co (Wisconsin)	2008	27,204,702	262,180	511,619,213	105,847,939	0.41	2,397	33,589	7,749
Northern States Power Co (Wisconsin)	2009	30,266,988	191,456	511,489,167	114,121,400	0.42	2,397	33,946	7,789
Northern States Power Co (Wisconsin)	2010	37,846,877	160,526	549,689,800	128,850,785	0.45	2,397	33,836	8,080
Northern States Power Co (Wisconsin)	2011	37,106,552	78,457	573,437,790	131,519,419	0.42	2,364	34,030	8,332
NorthWestern Corp	2007	51,518,851	866,494	589,915,330	131,808,428	0.35	8,120	22,960	10,625
NorthWestern Corp	2008	53,008,192	633,695	684,999,247	138,202,455	0.36	8,112	23,160	12,960
NorthWestern Corp	2009	60,525,227	212,930	532,536,712	144,561,058	0.36	8,113	23,587	13,044
NorthWestern Corp	2010	47,713,798	211,305	533,204,661	139,182,642	0.34	8,092	19,408	13,467
NorthWestern Corp	2011	54,040,017	203,710	501,543,506	142,601,282	0.32	8,114	19,486	14,272
NSTAR Electric Co	2007	131,950,988	2,519,201	1,937,943,748	523,975,217	0.38	903	33,527	38,166
NSTAR Electric Co	2008	137,758,165	2,414,945	2,029,615,912	569,510,817	0.39	918	34,012	38,716
NSTAR Electric Co	2009	121,074,096	2,295,208	1,817,018,056	600,034,816	0.40	951	34,049	40,396
NSTAR Electric Co	2010	149,338,323	2,405,339	1,779,124,657	724,136,619	0.46	951	35,070	41,038
NSTAR Electric Co	2011	151,807,508	2,465,124	1,767,204,060	790,803,201	0.48	951	31,969	41,072
Ohio Edison Co	2007	42,375,433	2,478,049	1,645,264,197	353,154,439	0.39	707	61,910	9,207
Ohio Edison Co	2008	26,987,908	2,222,466	1,680,173,149	345,877,140	0.35	707	61,992	8,987
Ohio Edison Co	2009	78,085,027	1,348,801	1,737,535,302	237,746,051	0.32	707	62,074	7,608
Ohio Edison Co	2010	49,629,834	1,810,245	1,011,897,470	136,362,789	0.19	707	62,156	7,944
Ohio Edison Co	2011	79,180,917	1,919,752	883,874,918	243,364,717	0.32	707	62,238	7,891
Ohio Power Co	2007	149,139,925	49,443	3,076,104,612	464,322,119	0.20	7,867	38,373	33,580
Ohio Power Co	2008	148,187,993	118,918	3,693,170,677	568,021,065	0.25	7,844	38,437	32,864

Schedule 2: Electric Utility Data Base

A	B	T	U	V	W	X	Y	Z	AA
Formula:					V-O	W/E			
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Ohio Power Co	2009	165,622,538	36,581	3,140,876,969	552,151,586	0.22	7,890	38,424	33,388
Ohio Power Co	2010	172,661,465	424,194	3,510,201,035	670,483,287	0.25	7,892	38,558	34,137
Ohio Power Co	2011	156,072,117	551,788	3,603,952,086	599,591,328	0.24	7,842	38,571	33,492
Oklahoma Gas & Electric Co	2007	105,208,480	4,716,642	1,414,947,835	217,945,476	0.31	4,625	38,174	22,156
Oklahoma Gas & Electric Co	2008	103,942,461	5,390,731	1,546,332,220	236,544,234	0.33	4,650	38,710	22,196
Oklahoma Gas & Electric Co	2009	90,790,720	4,793,035	1,243,932,108	242,607,096	0.29	4,676	39,844	22,766
Oklahoma Gas & Electric Co	2010	133,459,736	2,222,170	1,525,159,577	316,971,209	0.32	4,831	40,022	24,341
Oklahoma Gas & Electric Co	2011	133,258,784	4,186,359	1,567,119,110	355,814,175	0.32	4,879	42,903	24,361
Oncor Electric Delivery	2007	171,091,878	55,550	849,938,236	849,938,236	0.36	14,662	102,205	82,331
Oncor Electric Delivery	2008	159,972,306	177,803	850,988,545	850,988,545	0.35	14,905	102,679	83,223
Oncor Electric Delivery	2009	236,955,554	240,851	986,628,933	986,628,933	0.39	15,127	102,727	86,612
Oncor Electric Delivery	2010	290,554,106	0	1,008,829,496	1,008,829,496	0.37	15,304	103,063	89,819
Oncor Electric Delivery	2011	309,307,834	0	1,097,488,904	1,097,488,904	0.37	15,342	103,436	92,842
Orange & Rockland Utilities Inc	2007	44,155,525	22,319	382,907,326	108,471,308	0.52	516	5,212	6,945
Orange & Rockland Utilities Inc	2008	49,940,511	22,768	422,049,304	121,994,187	0.56	516	5,309	6,728
Orange & Rockland Utilities Inc	2009	63,275,579	50,191	343,730,288	141,940,656	0.59	516	5,460	6,728
Orange & Rockland Utilities Inc	2010	78,977,783	112,200	379,176,849	164,375,811	0.62	516	5,501	6,761
Orange & Rockland Utilities Inc	2011	79,368,332	57,704	338,958,933	163,204,007	0.58	519	5,551	6,866
Pacific Gas & Electric Co	2007	738,602,885	5,672,320	6,085,663,694	2,183,528,906	0.39	18,503	140,684	81,079
Pacific Gas & Electric Co	2008	765,714,825	3,902,283	7,478,608,321	2,533,325,900	0.43	18,650	141,036	83,538
Pacific Gas & Electric Co	2009	865,363,579	5,540,811	6,732,460,415	2,520,416,996	0.41	18,616	141,213	85,744
Pacific Gas & Electric Co	2010	784,331,979	8,649,009	6,783,337,248	2,434,056,041	0.38	18,583	141,346	86,197
Pacific Gas & Electric Co	2011	917,382,426	6,747,623	7,227,913,431	2,689,760,324	0.38	18,618	141,000	88,914
PECO Energy Co	2007	145,947,243	1,472,060	2,876,866,762	766,695,036	0.29	1,220	28,193	29,572
PECO Energy Co	2008	131,089,807	1,020,204	3,001,581,189	866,671,536	0.33	1,227	28,628	30,163
PECO Energy Co	2009	140,782,470	1,009,504	2,800,416,337	769,492,964	0.31	1,227	28,759	30,284
PECO Energy Co	2010	144,762,038	872,256	2,977,348,295	864,661,343	0.32	1,227	28,811	31,117
PECO Energy Co	2011	163,131,778	1,271,452	2,222,768,195	779,256,924	0.47	1,228	21,823	36,512
Pennsylvania Electric Co	2007	3,033,445	14,423	1,025,060,461	234,164,378	0.38	2,689	26,723	13,144
Pennsylvania Electric Co	2008	-5,434,672	25,182	1,103,381,006	227,374,961	0.36	2,701	26,825	13,096
Pennsylvania Electric Co	2009	19,872,965	11,884	1,094,610,538	208,002,671	0.37	2,701	26,927	13,220
Pennsylvania Electric Co	2010	32,410,693	9,738	1,270,755,854	262,656,737	0.49	2,701	27,029	13,171
Pennsylvania Electric Co	2011	65,519,384	24,000	725,883,090	185,097,547	0.34	2,701	27,131	13,378
Pennsylvania Power Co	2007	4,341,608	89,678	232,246,603	31,607,097	0.36	48	13,299	1,739
Pennsylvania Power Co	2008	-1,142,621	104,223	213,584,857	31,018,518	0.33	48	13,329	1,997
Pennsylvania Power Co	2009	4,505,097	79,824	194,152,115	31,117,240	0.30	48	13,359	1,902
Pennsylvania Power Co	2010	5,528,705	63,777	178,627,340	33,985,104	0.30	48	13,389	1,948
Pennsylvania Power Co	2011	13,418,159	99,149	163,133,770	50,491,651	0.40	48	13,419	1,948
Potomac Edison Co (The)	2007	48,360,071	67,355	758,487,215	113,462,956	0.46	1,244	22,068	13,745
Potomac Edison Co (The)	2008	45,558,390	58,289	821,405,449	113,179,175	0.47	1,245	22,484	12,563
Potomac Edison Co (The)	2009	45,610,476	8,741	895,162,236	111,298,766	0.41	1,245	23,869	14,055
Potomac Edison Co (The)	2010	44,177,560	500	834,691,809	107,790,939	0.42	1,249	16,983	11,063
Potomac Edison Co (The)	2011	44,993,989	0	702,954,259	104,224,567	0.39	1,248	19,015	13,347
PPL Electric Utilities Corp	2007	121,752,422	6,784,835	2,561,657,020	545,545,025	0.35	4,032	35,980	55,975
PPL Electric Utilities Corp	2008	125,729,981	5,884,684	2,541,658,601	555,306,674	0.35	4,009	36,229	56,841
PPL Electric Utilities Corp	2009	147,219,982	2,472,403	2,466,547,072	552,424,203	0.36	4,063	36,300	57,685
PPL Electric Utilities Corp	2010	149,721,597	2,523,886	1,967,605,506	575,680,730	0.52	4,076	36,414	58,891
PPL Electric Utilities Corp	2011	126,833,921	2,315,570	1,350,446,082	587,296,881	0.49	4,056	40,552	60,116

Schedule 2: Electric Utility Data Base

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Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
Progress Energy Carolinas	2007	269,167,999	4,590,270	2,717,049,940	499,925,176	0.23	5,858	65,000	97,050
Progress Energy Carolinas	2008	285,798,665	3,220,911	2,739,853,263	512,657,439	0.23	5,872	65,000	97,632
Progress Energy Carolinas	2009	279,027,818	3,646,748	3,006,286,188	531,479,230	0.25	6,024	67,000	100,314
Progress Energy Carolinas	2010	298,077,713	1,365,059	3,178,993,911	566,412,379	0.25	6,025	67,000	83,800
Progress Energy Carolinas	2011	302,864,900	1,022,761	2,912,515,602	613,166,176	0.28	6,163	67,000	84,242
Progress Energy Florida	2007	269,689,539	1,964,040	3,409,361,231	599,507,682	0.32	4,885	31,000	36,549
Progress Energy Florida	2008	265,143,985	1,774,613	3,721,321,145	560,298,662	0.36	4,923	31,000	38,771
Progress Energy Florida	2009	211,970,312	1,252,670	3,473,512,611	515,225,129	0.22	4,944	31,000	40,058
Progress Energy Florida	2010	298,427,858	1,333,482	3,741,128,720	624,211,210	0.29	5,023	31,000	42,247
Progress Energy Florida	2011	264,732,639	1,516,750	3,346,194,116	585,037,505	0.36	5,098	31,000	43,148
Public Service Co of Colorado	2007	149,187,927	540,030	2,054,238,735	327,049,098	0.31	4,153	85,187	20,678
Public Service Co of Colorado	2008	144,210,170	534,560	2,368,876,001	334,238,602	0.32	4,144	85,778	21,223
Public Service Co of Colorado	2009	155,077,541	605,888	1,993,318,498	404,835,878	0.36	4,357	86,021	24,582
Public Service Co of Colorado	2010	162,738,747	497,046	2,201,451,088	451,858,150	0.33	4,393	86,660	25,743
Public Service Co of Colorado	2011	159,852,929	538,671	2,127,594,725	452,343,092	0.30	4,718	87,488	27,702
Public Service Co of New Mexico	2007	90,819,121	5,764,742	1,018,602,481	174,907,798	0.55	3,162	11,218	12,222
Public Service Co of New Mexico	2008	95,104,294	5,330,235	1,001,669,401	181,721,860	0.50	3,164	11,390	12,313
Public Service Co of New Mexico	2009	113,287,053	6,041,161	769,685,706	196,820,529	0.50	3,171	11,438	12,312
Public Service Co of New Mexico	2010	131,157,245	4,997,801	769,790,602	214,218,136	0.46	3,189	11,341	12,391
Public Service Co of New Mexico	2011	132,140,770	5,524,655	773,355,410	217,974,889	0.44	3,189	11,373	12,727
Public Service Co of Oklahoma	2007	57,916,590	51,766	1,250,246,754	270,113,192	0.65	3,674	17,498	15,766
Public Service Co of Oklahoma	2008	59,298,675	74,063	1,334,300,306	134,882,981	0.30	3,621	17,572	16,704
Public Service Co of Oklahoma	2009	57,136,240	64,805	793,417,655	207,760,256	0.39	3,622	17,743	16,962
Public Service Co of Oklahoma	2010	65,023,392	33,697	935,265,426	239,383,214	0.42	3,628	17,498	16,455
Public Service Co of Oklahoma	2011	54,968,620	28,317	976,015,295	225,434,286	0.37	3,600	17,483	17,120
Public Service Electric & Gas Co	2007	213,526,579	3,036,120	4,059,620,891	715,937,001	0.41	1,425	20,339	32,354
Public Service Electric & Gas Co	2008	215,263,791	3,225,316	4,535,600,682	760,662,391	0.44	1,428	21,736	32,965
Public Service Electric & Gas Co	2009	226,158,491	2,410,424	4,129,812,418	834,611,785	0.46	1,357	21,900	33,128
Public Service Electric & Gas Co	2010	201,696,884	1,976,792	3,881,103,380	808,481,031	0.43	1,401	22,165	33,723
Public Service Electric & Gas Co	2011	173,318,928	1,074,670	3,440,928,260	765,279,698	0.37	1,430	22,123	34,133
San Diego Gas & Electric Co	2007	232,845,768	93,574	1,480,997,958	660,000,381	0.47	1,895	22,056	17,801
San Diego Gas & Electric Co	2008	241,461,781	0	1,792,872,453	697,868,938	0.46	1,912	22,198	18,333
San Diego Gas & Electric Co	2009	253,592,076	0	1,639,593,347	708,212,445	0.45	1,920	22,297	18,669
San Diego Gas & Electric Co	2010	354,745,103	0	1,742,308,816	753,632,403	0.45	1,925	22,360	18,221
San Diego Gas & Electric Co	2011	437,623,309	0	2,310,803,842	849,006,865	0.44	1,935	22,449	18,292
South Carolina Electric & Gas Co	2007	133,900,419	2,468,321	1,156,705,969	245,242,385	0.23	3,387	24,045	25,050
South Carolina Electric & Gas Co	2008	143,098,619	2,167,850	1,378,778,096	262,690,238	0.23	3,395	24,509	25,044
South Carolina Electric & Gas Co	2009	126,949,111	1,881,566	1,299,234,454	252,652,524	0.23	3,423	24,739	25,284
South Carolina Electric & Gas Co	2010	138,449,967	1,632,223	1,461,078,295	264,721,529	0.23	3,437	24,908	26,144
South Carolina Electric & Gas Co	2011	136,973,126	1,508,007	1,451,137,058	262,731,359	0.21	3,444	25,058	26,940
Southern California Edison Co	2007	878,552,525	18,086,404	7,171,655,235	2,250,156,900	0.42	12,235	111,550	85,489
Southern California Edison Co	2008	929,990,088	16,964,776	8,823,128,723	2,332,349,998	0.62	12,264	111,500	87,633
Southern California Edison Co	2009	1,045,693,826	14,702,166	6,090,393,785	2,440,746,776	0.39	12,278	113,500	93,583
Southern California Edison Co	2010	1,094,090,417	13,803,813	6,533,571,874	2,646,976,830	0.41	12,278	103,500	98,899
Southern California Edison Co	2011	1,114,501,521	9,627,895	7,563,556,731	2,773,948,533	0.48	12,287	103,000	103,011
Southern Indiana Gas & Electric Co	2007	32,795,651	588,053	292,102,840	54,065,407	0.22	928	6,089	8,483
Southern Indiana Gas & Electric Co	2008	32,287,183	1,305,464	324,918,687	66,165,208	0.25	923	6,200	7,247
Southern Indiana Gas & Electric Co	2009	37,771,070	1,364,198	329,683,435	74,468,925	0.27	930	6,200	7,465

Schedule 2: Electric Utility Data Base

A	B	T	U	V	W	X	Y	Z	AA
Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
Southern Indiana Gas & Electric Co	2010	38,282,480	2,285,594	374,793,153	78,283,746	0.25	989	6,246	7,824
Southern Indiana Gas & Electric Co	2011	37,662,758	3,884,936	393,348,033	79,937,237	0.25	985	6,280	7,829
Southwestern Electric Power Co	2007	57,053,070	0	1,113,744,479	177,446,420	0.36	3,757	17,593	21,615
Southwestern Electric Power Co	2008	59,899,523	0	1,215,965,830	190,817,312	0.34	3,882	17,610	22,347
Southwestern Electric Power Co	2009	69,645,125	230	950,431,426	183,512,822	0.34	3,859	17,638	22,953
Southwestern Electric Power Co	2010	75,073,664	-22	1,087,217,819	213,750,540	0.33	3,972	17,787	23,331
Southwestern Electric Power Co	2011	70,768,930	31	1,169,247,021	219,943,141	0.31	4,021	17,862	23,292
Southwestern Public Service Co	2007	64,731,311	471,449	1,439,571,236	164,308,529	0.41	6,336	41,825	16,139
Southwestern Public Service Co	2008	66,368,636	629,659	1,767,758,881	176,075,732	0.42	6,677	43,597	16,558
Southwestern Public Service Co	2009	75,155,407	663,198	1,162,089,260	192,716,002	0.38	6,517	44,149	17,708
Southwestern Public Service Co	2010	85,998,532	577,987	1,297,465,572	220,680,055	0.40	6,517	42,293	19,137
Southwestern Public Service Co	2011	84,072,387	654,850	1,371,596,916	243,104,322	0.41	6,703	42,513	21,945
Tampa Electric Co	2007	103,921,266	1,823,084	1,466,597,961	211,761,972	0.24	1,309	14,030	14,270
Tampa Electric Co	2008	94,222,661	2,016,069	1,572,274,917	209,235,669	0.29	1,315	10,885	14,166
Tampa Electric Co	2009	122,366,685	1,122,664	1,413,422,241	251,860,441	0.23	1,316	10,885	14,551
Tampa Electric Co	2010	127,190,177	1,110,175	1,344,354,650	264,365,615	0.23	1,322	10,998	14,670
Tampa Electric Co	2011	102,285,214	1,256,181	1,227,283,935	232,059,462	0.23	1,328	10,998	14,704
Toledo Edison Co (The)	2007	34,960,386	315,536	663,192,449	148,887,806	0.33	223	17,589	2,377
Toledo Edison Co (The)	2008	20,956,343	215,949	608,078,220	139,731,733	0.33	223	17,590	2,885
Toledo Edison Co (The)	2009	35,688,090	168,670	671,229,619	92,932,351	0.36	223	17,591	2,433
Toledo Edison Co (The)	2010	25,750,182	231,619	349,710,124	57,902,591	0.26	223	17,592	2,565
Toledo Edison Co (The)	2011	31,023,536	253,580	311,330,199	87,915,384	0.35	223	17,593	2,612
Tucson Electric Power Co	2007	69,569,059	0	823,776,241	124,945,133	0.31	2,477	6,832	13,572
Tucson Electric Power Co	2008	71,423,722	0	915,903,165	131,378,011	0.41	2,427	7,014	13,932
Tucson Electric Power Co	2009	85,154,633	0	791,807,021	146,743,791	0.31	2,041	7,367	13,932
Tucson Electric Power Co	2010	78,298,708	0	803,093,928	144,407,015	0.29	2,049	7,395	15,057
Tucson Electric Power Co	2011	76,527,384	0	815,363,491	138,921,307	0.28	2,076	7,412	14,579
Unitil Energy Systems	2007	7,482,134	0	133,689,336	26,474,367	0.53		2,007	248
Unitil Energy Systems	2008	8,254,181	0	140,043,067	31,641,589	0.61		2,026	248
Unitil Energy Systems	2009	7,361,803	0	124,177,396	31,711,181	0.59		2,033	254
Unitil Energy Systems	2010	7,879,291	0	114,991,607	39,261,786	0.61		1,987	253
Unitil Energy Systems	2011	8,300,794	0	98,553,573	37,372,761	0.56		1,554	269
UNS Electric Inc	2007	7,392,458	0	140,023,501	26,267,368	0.48	307	3,510	1,195
UNS Electric Inc	2008	7,419,718	85	164,714,037	27,979,085	0.48	319	3,548	1,234
UNS Electric Inc	2009	8,416,039	0	152,425,578	28,074,828	0.45	320	3,581	1,356
UNS Electric Inc	2010	7,235,105	0	175,392,077	27,355,237	0.41	327	3,599	1,376
UNS Electric Inc	2011	7,345,531	0	167,656,400	29,520,943	0.36	330	3,616	1,494
Virginia Electric & Power Co	2007	372,781,310	0	4,275,366,624	706,548,175	0.28	6,091	55,000	67,176
Virginia Electric & Power Co	2008	401,340,963	0	4,613,332,191	748,792,991	0.25	6,098	56,000	68,046
Virginia Electric & Power Co	2009	449,678,738	0	5,003,263,390	922,467,737	0.37	6,108	56,000	70,773
Virginia Electric & Power Co	2010	632,267,787	0	4,673,558,041	1,043,369,900	0.29	6,168	56,800	72,711
Virginia Electric & Power Co	2011	396,566,370	0	4,427,419,067	882,221,006	0.24	6,357	56,800	74,884
West Penn Power Co	2007	56,925,818	134,296	1,007,207,235	183,979,998	0.46	1,692	25,442	15,290
West Penn Power Co	2008	57,588,814	112,788	1,054,981,867	186,180,100	0.46	1,693	25,300	15,538
West Penn Power Co	2009	55,965,193	16,330	1,097,721,688	179,244,993	0.40	1,700	27,274	12,092
West Penn Power Co	2010	60,900,312	0	1,290,154,666	213,840,090	0.43	1,695	25,662	13,526
West Penn Power Co	2011	65,726,101	0	883,569,138	188,715,585	0.43	1,695	20,026	13,961
Westar Energy Inc	2007	65,350,299	4,982	652,647,955	185,077,282	0.35	3,492	27,600	12,259

Schedule 2: Electric Utility Data Base

A	B	T	U	V	W	X	Y	Z	AA
Formula:					V-O	W/E			
Utility Name	Year	Total A&G Expenses	O&M- Total Sales Expenses	Total O&M Expenses	O&M less Production	Operating Ratio	Miles of Transmission	Miles of Distribution	Substation Capacity (MVa)
Westar Energy Inc	2008	67,048,033	1,998	728,953,249	183,576,347	0.36	3,560	27,900	13,063
Westar Energy Inc	2009	74,498,931	840	686,698,592	211,491,042	0.36	3,631	28,000	13,310
Westar Energy Inc	2010	85,256,169	1,103	726,656,876	230,809,292	0.33	3,668	28,100	13,094
Westar Energy Inc	2011	86,818,489	1,449	729,111,115	238,802,160	0.32	3,608	28,200	21,806
Wheeling Power Co	2007	2,252,951	102	52,811,291	10,371,207	0.18	198	1,505	907
Wheeling Power Co	2008	2,120,306	220	60,206,682	10,988,412	0.18	198	1,507	864
Wheeling Power Co	2009	2,444,004	155	65,075,166	10,002,418	0.16	198	1,507	864
Wheeling Power Co	2010	2,318,505	387	88,951,301	14,816,834	0.22	201	1,507	947
Wheeling Power Co	2011	2,348,911	40	94,730,786	10,759,527	0.15	208	1,519	953
Wisconsin Electric Power Co	2007	160,727,547	260,369	1,957,092,993	489,762,470	0.39		44,490	68,964
Wisconsin Electric Power Co	2008	171,289,179	276,815	2,449,654,946	667,722,354	0.72		45,420	69,424
Wisconsin Electric Power Co	2009	170,792,064	335	2,194,528,594	621,825,992	0.55		45,715	70,500
Wisconsin Electric Power Co	2010	230,112,709	232,975	2,432,106,903	729,157,319	0.57		45,343	77,549
Wisconsin Electric Power Co	2011	216,648,959	743,110	2,501,745,490	724,045,244	0.50		45,412	74,329
Wisconsin Power & Light Co	2007	68,205,413	0	905,110,820	228,919,615	0.45		20,921	4,479
Wisconsin Power & Light Co	2008	66,288,992	0	923,956,597	235,629,578	0.46		21,076	4,684
Wisconsin Power & Light Co	2009	62,173,301	0	905,397,310	227,410,633	0.45		21,100	4,863
Wisconsin Power & Light Co	2010	68,870,064	0	871,159,469	247,684,518	0.40		21,263	5,096
Wisconsin Power & Light Co	2011	69,871,996	0	830,309,681	253,471,952	0.38		21,327	5,283
Wisconsin Public Service Corp	2007	79,068,278	51,840	932,109,941	247,461,340	0.53		21,496	8,477
Wisconsin Public Service Corp	2008	81,812,928	122	946,107,222	257,780,642	0.47		21,500	8,683
Wisconsin Public Service Corp	2009	101,269,680	0	900,311,429	279,198,466	0.48		21,500	8,863
Wisconsin Public Service Corp	2010	93,959,877	0	899,021,538	297,686,064	0.47		21,500	8,871
Wisconsin Public Service Corp	2011	88,815,577	0	920,972,327	299,053,562	0.48		21,700	8,825

Schedule 2: Electric Utility Data Base

A	B	AB	AC	AD	AE	AF	AG	AH	AI
Formula:		J*(1-X)+(X*W)	%Δ in AB		AD/(Y+Z)	Base ≈ 16.89	AD/AF	(AG*0.4)+(AA*0.6)	%Δ in AH
Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
ALLETE Inc	2007	303,449,791		140,750	16.89	1.00	140,750	61,858	
ALLETE Inc	2008	311,135,402	1.03	141,555	17.22	1.02	138,818	61,439	0.99
ALLETE Inc	2009	382,001,619	1.23	143,842	16.58	0.98	146,486	64,350	1.05
ALLETE Inc	2010	413,660,043	1.08	145,661	16.92	1.00	145,387	64,620	1.00
ALLETE Inc	2011	441,150,083	1.07	143,712	16.44	0.97	147,624	65,532	1.01
Ameren Missouri	2007	1,957,328,214		1,179,795	33.64	1.99	592,170	263,524	
Ameren Missouri	2008	2,072,583,031	1.06	1,196,124	33.65	1.99	600,250	267,159	1.01
Ameren Missouri	2009	2,228,593,124	1.08	1,187,617	33.36	1.98	601,161	267,965	1.00
Ameren Missouri	2010	2,432,663,800	1.09	1,190,877	33.43	1.98	601,507	268,398	1.00
Ameren Missouri	2011	2,474,289,107	1.02	1,190,483	33.18	1.96	605,912	264,657	0.99
Appalachian Power Co	2007	2,094,618,906		951,798	18.36	1.09	875,252	375,409	
Appalachian Power Co	2008	2,244,301,222	1.07	957,963	18.41	1.09	878,443	375,853	1.00
Appalachian Power Co	2009	2,341,696,622	1.04	959,922	18.41	1.09	880,621	376,692	1.00
Appalachian Power Co	2010	2,426,499,414	1.04	961,336	18.40	1.09	882,006	377,244	1.00
Appalachian Power Co	2011	2,557,768,073	1.05	961,248	18.38	1.09	883,332	378,057	1.00
Arizona Public Service Co	2007	3,437,847,430		1,086,388	31.53	1.87	581,881	255,991	
Arizona Public Service Co	2008	3,472,473,480	1.01	1,101,956	32.62	1.93	570,417	249,935	0.98
Arizona Public Service Co	2009	3,672,909,568	1.06	1,108,829	32.16	1.90	582,153	255,411	1.02
Arizona Public Service Co	2010	3,939,838,195	1.07	1,115,360	32.42	1.92	580,911	255,328	1.00
Arizona Public Service Co	2011	4,106,316,855	1.04	1,120,282	32.17	1.90	588,117	259,002	1.01
Avista Corp	2007	660,618,087		347,097	17.40	1.03	336,925	138,473	
Avista Corp	2008	709,967,282	1.07	352,352	17.34	1.03	343,089	140,840	1.02
Avista Corp	2009	840,657,575	1.18	355,078	17.74	1.05	338,040	138,946	0.99
Avista Corp	2010	797,330,375	0.95	356,682	17.48	1.03	344,642	141,564	1.02
Avista Corp	2011	838,426,618	1.05	358,303	17.47	1.03	346,331	142,224	1.00
Baltimore Gas & Electric Co	2007	1,659,126,007		1,221,284	49.02	2.90	420,727	187,269	
Baltimore Gas & Electric Co	2008	1,564,641,223	0.94	1,229,181	48.36	2.86	429,170	191,210	1.02
Baltimore Gas & Electric Co	2009	1,837,828,238	1.17	1,234,644	48.53	2.87	429,568	195,032	1.02
Baltimore Gas & Electric Co	2010	1,980,605,924	1.08	1,236,939	48.00	2.84	435,151	195,322	1.00
Baltimore Gas & Electric Co	2011	2,085,589,493	1.05	1,240,291	48.24	2.86	434,183	196,410	1.01
CenterPoint Energy Houston Electric LLC	2007	2,524,485,225		2,035,875	40.57	2.40	847,371	369,300	
CenterPoint Energy Houston Electric LLC	2008	2,532,198,951	1.00	2,080,365	40.73	2.41	862,453	375,641	1.02
CenterPoint Energy Houston Electric LLC	2009	2,582,377,402	1.02	2,109,703	40.89	2.42	871,202	379,229	1.01
CenterPoint Energy Houston Electric LLC	2010	2,638,640,050	1.02	2,132,480	40.99	2.43	878,385	382,885	1.01
CenterPoint Energy Houston Electric LLC	2011	2,746,143,697	1.04	2,165,283	41.21	2.44	887,276	386,364	1.01
Central Hudson Gas & Electric Corp	2007	308,983,031		293,205	29.45	1.74	168,099	69,866	
Central Hudson Gas & Electric Corp	2008	322,985,672	1.05	288,262	28.60	1.69	170,176	70,994	1.02
Central Hudson Gas & Electric Corp	2009	348,827,785	1.08	282,073	27.85	1.65	171,037	71,122	1.00
Central Hudson Gas & Electric Corp	2010	381,899,114	1.09	277,984	27.18	1.61	172,726	71,862	1.01
Central Hudson Gas & Electric Corp	2011	406,414,801	1.06	274,156	29.39	1.74	157,521	65,777	0.92
Central Vermont Public Service Corp	2007	141,144,442		157,919	16.74	0.99	159,280	64,347	
Central Vermont Public Service Corp	2008	147,391,863	1.04	158,700	16.63	0.98	161,129	65,113	1.01
Central Vermont Public Service Corp	2009	157,160,651	1.07	159,039	16.63	0.98	161,485	65,255	1.00
Central Vermont Public Service Corp	2010	158,073,405	1.01	159,342	16.62	0.98	161,937	65,457	1.00
Central Vermont Public Service Corp	2011	170,224,414	1.08	160,109	16.60	0.98	162,915	65,849	1.01

Schedule 2: Electric Utility Data Base

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Formula:		J*(1-X)+(X*W)	%Δ in AB		AD/(Y+Z)	Base ≈ 16.89	AD/AF	(AG*0.4)+(AA*0.6)	%Δ in AH
Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
Chugach Electric Association Inc	2007	212,319,651		78,233	35.10	2.08	37,634	17,499	
Chugach Electric Association Inc	2008	205,322,133	0.97	78,657	35.10	2.08	37,837	17,620	1.01
Chugach Electric Association Inc	2009	202,659,361	0.99	78,469	34.90	2.07	37,961	17,670	1.00
Chugach Electric Association Inc	2010	216,253,428	1.07	78,705	34.90	2.07	38,080	17,718	1.00
Chugach Electric Association Inc	2011	191,893,359	0.89	78,971	35.10	2.08	37,995	17,684	1.00
CLECO Power LLC	2007	603,417,756		273,050	21.59	1.28	213,563	92,562	
CLECO Power LLC	2008	650,017,349	1.08	275,528	21.65	1.28	214,933	93,211	1.01
CLECO Power LLC	2009	677,398,207	1.04	277,381	21.65	1.28	216,318	93,784	1.01
CLECO Power LLC	2010	836,509,663	1.23	279,213	21.62	1.28	218,075	94,503	1.01
CLECO Power LLC	2011	932,152,817	1.11	280,862	21.57	1.28	219,842	96,070	1.02
Cleveland Electric Illuminating Co (The)	2007	996,327,558		758,320	21.53	1.27	594,860	242,649	
Cleveland Electric Illuminating Co (The)	2008	1,056,627,735	1.06	755,807	21.43	1.27	595,569	242,926	1.00
Cleveland Electric Illuminating Co (The)	2009	1,088,034,822	1.03	753,865	21.35	1.26	596,279	244,343	1.01
Cleveland Electric Illuminating Co (The)	2010	1,190,941,345	1.09	752,207	21.28	1.26	596,988	244,597	1.00
Cleveland Electric Illuminating Co (The)	2011	1,189,362,533	1.00	748,935	21.18	1.25	597,180	244,739	1.00
Commonwealth Edison Co	2007	5,390,745,021		3,786,656	44.98	2.66	1,421,452	615,185	
Commonwealth Edison Co	2008	5,915,966,635	1.10	3,806,862	43.86	2.60	1,465,706	634,098	1.03
Commonwealth Edison Co	2009	6,294,721,286	1.06	3,792,295	54.56	3.23	1,173,784	517,295	0.82
Commonwealth Edison Co	2010	6,776,457,112	1.08	3,801,999	53.76	3.18	1,194,298	525,554	1.02
Commonwealth Edison Co	2011	6,906,503,774	1.02	3,818,690	53.89	3.19	1,196,474	527,024	1.00
Consolidated Edison Co of New York Inc	2007	7,991,091,143		3,236,037	24.70	1.46	2,211,965	912,175	
Consolidated Edison Co of New York Inc	2008	8,793,187,101	1.10	3,261,503	24.70	1.46	2,230,139	919,764	1.01
Consolidated Edison Co of New York Inc	2009	9,320,024,583	1.06	3,277,855	24.67	1.46	2,243,982	925,435	1.01
Consolidated Edison Co of New York Inc	2010	9,940,605,329	1.07	3,308,063	24.76	1.47	2,256,126	930,465	1.01
Consolidated Edison Co of New York Inc	2011	10,649,696,095	1.07	3,329,304	24.85	1.47	2,262,441	930,372	1.00
Consumers Energy Co	2007	1,950,102,176		1,797,388	25.66	1.52	1,183,013	487,177	
Consumers Energy Co	2008	2,142,524,002	1.10	1,804,233	25.68	1.52	1,186,390	489,587	1.00
Consumers Energy Co	2009	2,163,170,342	1.01	1,787,255	25.36	1.50	1,189,818	488,465	1.00
Consumers Energy Co	2010	2,290,079,013	1.06	1,788,636	25.31	1.50	1,193,246	489,285	1.00
Consumers Energy Co	2011	2,461,438,027	1.07	1,788,800	25.29	1.50	1,194,496	490,218	1.00
Detroit Edison Co (The)	2007	2,757,586,493		2,163,365	47.23	2.80	773,530	329,478	
Detroit Edison Co (The)	2008	2,675,109,650	0.97	2,150,426	47.15	2.79	770,162	328,166	1.00
Detroit Edison Co (The)	2009	3,095,658,376	1.16	2,133,006	46.57	2.76	773,349	329,342	1.00
Detroit Edison Co (The)	2010	2,958,782,536	0.96	2,119,752	46.22	2.74	774,462	329,845	1.00
Detroit Edison Co (The)	2011	3,259,427,189	1.10	2,120,265	45.85	2.71	780,947	332,513	1.01
Duke Energy Carolinas	2007	4,900,220,635		2,330,296	21.73	1.29	1,810,670	779,270	
Duke Energy Carolinas	2008	4,983,935,863	1.02	2,364,469	21.84	1.29	1,827,712	786,448	1.01
Duke Energy Carolinas	2009	5,145,308,759	1.03	2,376,889	21.76	1.29	1,844,730	793,649	1.01
Duke Energy Carolinas	2010	5,230,335,627	1.02	2,388,611	21.72	1.29	1,856,773	798,487	1.01
Duke Energy Carolinas	2011	5,624,373,662	1.08	2,396,581	21.79	1.29	1,857,440	798,868	1.00
Duke Energy Indiana	2007	1,369,049,379		773,979	21.88	1.30	597,274	254,121	
Duke Energy Indiana	2008	1,421,176,763	1.04	776,674	21.35	1.26	614,245	261,175	1.03
Duke Energy Indiana	2009	1,472,771,655	1.04	776,161	21.12	1.25	620,666	263,840	1.01
Duke Energy Indiana	2010	1,526,999,088	1.04	781,830	21.50	1.27	613,989	260,793	0.99
Duke Energy Indiana	2011	1,549,889,989	1.01	782,890	21.60	1.28	611,995	260,268	1.00

Schedule 2: Electric Utility Data Base

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Formula:		J*(1-X)+(X*W)	%Δ in AB		AD/(Y+Z)	Base ≈ 16.89	AD/AF	(AG*0.4)+(AA*0.6)	%Δ in AH
Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
Duke Energy Ohio	2007	1,194,797,179		686,615	31.61	1.87	366,806	182,191	
Duke Energy Ohio	2008	1,226,597,860	1.03	687,965	31.66	1.88	366,878	183,701	1.01
Duke Energy Ohio	2009	1,307,251,426	1.07	683,617	31.45	1.86	367,009	183,989	1.00
Duke Energy Ohio	2010	1,365,009,169	1.04	684,540	31.49	1.87	367,017	184,006	1.00
Duke Energy Ohio	2011	1,241,651,605	0.91	685,865	31.41	1.86	368,734	184,705	1.00
Empire District Electric Co (The)	2007	375,490,000		166,497	20.48	1.21	137,302	58,045	
Empire District Electric Co (The)	2008	394,748,425	1.05	167,669	20.44	1.21	138,521	58,564	1.01
Empire District Electric Co (The)	2009	397,433,749	1.01	168,023	20.36	1.21	139,348	58,985	1.01
Empire District Electric Co (The)	2010	412,776,228	1.04	168,618	20.37	1.21	139,763	59,166	1.00
Empire District Electric Co (The)	2011	439,509,535	1.06	166,236	20.28	1.20	138,401	58,688	0.99
Fitchburg Gas & Electric Light Co	2007	34,399,523		28,372	37.21	2.20	12,874	5,901	
Fitchburg Gas & Electric Light Co	2008	34,008,313	0.99	28,392	38.35	2.27	12,502	5,377	0.91
Fitchburg Gas & Electric Light Co	2009	35,693,640	1.05	28,474	38.46	2.28	12,502	5,377	1.00
Fitchburg Gas & Electric Light Co	2010	38,397,546	1.08	28,731	38.65	2.29	12,553	5,397	1.00
Fitchburg Gas & Electric Light Co	2011	38,713,109	1.01	28,854	55.50	3.29	8,779	3,885	0.72
Florida Power & Light Co	2007	7,056,223,798		4,496,597	61.27	3.63	1,239,158	573,730	
Florida Power & Light Co	2008	7,563,744,528	1.07	4,509,743	61.48	3.64	1,238,709	575,055	1.00
Florida Power & Light Co	2009	7,938,192,683	1.05	4,499,084	61.09	3.62	1,243,618	579,348	1.01
Florida Power & Light Co	2010	7,694,379,898	0.97	4,520,332	61.02	3.61	1,250,897	582,842	1.01
Florida Power & Light Co	2011	7,871,963,917	1.02	4,547,052	61.31	3.63	1,252,381	583,433	1.00
Idaho Power Co	2007	856,645,469		477,094	6.88	0.41	1,171,242	476,641	
Idaho Power Co	2008	941,880,228	1.10	484,535	6.94	0.41	1,178,349	479,579	1.01
Idaho Power Co	2009	990,738,265	1.05	488,175	15.53	0.92	530,665	220,750	0.46
Idaho Power Co	2010	1,037,899,526	1.05	490,705	15.60	0.92	531,170	223,011	1.01
Idaho Power Co	2011	1,012,501,827	0.98	493,532	15.68	0.93	531,638	223,283	1.00
Indiana Michigan Power Co	2007	1,080,025,634		581,996	26.41	1.56	372,097	164,830	
Indiana Michigan Power Co	2008	1,156,187,948	1.07	582,865	26.47	1.57	371,875	164,756	1.00
Indiana Michigan Power Co	2009	1,268,849,392	1.10	582,328	26.46	1.57	371,639	164,921	1.00
Indiana Michigan Power Co	2010	1,203,100,178	0.95	582,821	26.49	1.57	371,572	164,841	1.00
Indiana Michigan Power Co	2011	1,265,360,754	1.05	582,947	26.49	1.57	371,578	165,145	1.00
Indianapolis Power & Light	2007	434,343,888		468,667	37.62	2.23	210,352	92,144	
Indianapolis Power & Light	2008	416,787,904	0.96	468,203	39.25	2.32	201,452	88,620	0.96
Indianapolis Power & Light	2009	404,943,897	0.97	467,683	37.83	2.24	208,762	91,544	1.03
Indianapolis Power & Light	2010	405,535,046	1.00	468,161	37.93	2.25	208,415	91,489	1.00
Indianapolis Power & Light	2011	393,394,782	0.97	468,195	38.81	2.30	203,683	89,687	0.98
Interstate Power & Light Co	2007	845,439,367		528,104	23.65	1.40	376,996	153,258	
Interstate Power & Light Co	2008	811,167,307	0.96	526,612	23.51	1.39	378,161	153,733	1.00
Interstate Power & Light Co	2009	828,303,282	1.02	526,035	23.48	1.39	378,245	153,923	1.00
Interstate Power & Light Co	2010	918,809,905	1.11	526,426	23.43	1.39	379,394	155,126	1.01
Interstate Power & Light Co	2011	912,726,061	0.99	526,741	23.43	1.39	379,562	155,266	1.00
Jersey Central Power & Light Co	2007	1,886,436,760		1,085,244	44.47	2.63	412,129	202,887	
Jersey Central Power & Light Co	2008	1,988,577,270	1.05	1,089,980	44.37	2.63	414,780	205,308	1.01
Jersey Central Power & Light Co	2009	2,021,212,024	1.02	1,093,885	44.29	2.62	417,009	205,840	1.00
Jersey Central Power & Light Co	2010	2,074,535,562	1.03	1,097,078	44.19	2.62	419,238	208,835	1.01
Jersey Central Power & Light Co	2011	1,918,234,586	0.92	1,099,194	44.04	2.61	421,463	209,504	1.00

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Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
Kentucky Power Co	2007	476,100,095		175,806	16.04	0.95	185,060	78,197	
Kentucky Power Co	2008	496,176,012	1.04	175,730	15.95	0.94	186,081	78,369	1.00
Kentucky Power Co	2009	530,808,516	1.07	175,098	15.85	0.94	186,487	78,618	1.00
Kentucky Power Co	2010	533,219,128	1.00	174,682	15.76	0.93	187,213	78,894	1.00
Kentucky Power Co	2011	543,022,738	1.02	173,756	15.64	0.93	187,646	79,244	1.00
Kingsport Power Co	2007	48,248,942		47,624	35.08	2.08	22,925	9,601	
Kingsport Power Co	2008	45,891,711	0.95	46,961	34.59	2.05	22,925	9,601	1.00
Kingsport Power Co	2009	37,152,061	0.81	47,027	34.61	2.05	22,942	9,608	1.00
Kingsport Power Co	2010	59,182,329	1.59	47,183	34.76	2.06	22,923	9,601	1.00
Kingsport Power Co	2011	53,401,076	0.90	47,436	34.91	2.07	22,942	9,608	1.00
Madison Gas & Electric Co	2007	177,499,345		137,563	69.44	4.11	33,451	14,081	
Madison Gas & Electric Co	2008	180,921,206	1.02	139,452	70.32	4.16	33,485	14,104	1.00
Madison Gas & Electric Co	2009	192,341,873	1.06	140,057	70.66	4.18	33,468	14,120	1.00
Madison Gas & Electric Co	2010	209,801,464	1.09	140,702	69.83	4.14	34,025	14,344	1.02
Madison Gas & Electric Co	2011	232,154,578	1.11	141,416	69.77	4.13	34,228	14,426	1.01
MDU Resources Group Inc	2007	112,773,876		119,882	15.87	0.94	127,568	53,367	
MDU Resources Group Inc	2008	126,528,013	1.12	121,124	16.06	0.95	127,353	53,308	1.00
MDU Resources Group Inc	2009	132,370,349	1.05	122,134	15.97	0.95	129,107	54,035	1.01
MDU Resources Group Inc	2010	147,359,238	1.11	123,569	16.16	0.96	129,141	54,079	1.00
MDU Resources Group Inc	2011	163,110,441	1.11	125,802	16.45	0.97	129,144	54,221	1.00
Metropolitan Edison Co	2007	750,340,656		543,864	27.35	1.62	335,796	140,295	
Metropolitan Edison Co	2008	794,613,860	1.06	547,610	27.44	1.63	336,954	140,993	1.00
Metropolitan Edison Co	2009	970,460,753	1.22	549,871	27.48	1.63	337,865	141,459	1.00
Metropolitan Edison Co	2010	925,541,073	0.95	551,827	27.51	1.63	338,777	141,846	1.00
Metropolitan Edison Co	2011	1,105,444,087	1.19	552,684	27.47	1.63	339,689	142,285	1.00
Monongahela Power Co	2007	522,516,388		378,562	16.30	0.97	392,121	165,325	
Monongahela Power Co	2008	513,097,642	0.98	381,196	16.33	0.97	394,262	165,553	1.00
Monongahela Power Co	2009	537,567,359	1.05	383,623	15.24	0.90	424,975	178,183	1.08
Monongahela Power Co	2010	618,489,892	1.15	385,506	16.51	0.98	394,240	166,599	0.93
Monongahela Power Co	2011	603,806,965	0.98	386,822	17.26	1.02	378,451	162,345	0.97
Northern States Power Co (Minnesota)	2007	1,967,960,828		1,327,066	13.37	0.79	1,675,991	696,173	
Northern States Power Co (Minnesota)	2008	2,079,829,541	1.06	1,344,989	13.43	0.80	1,691,394	702,484	1.01
Northern States Power Co (Minnesota)	2009	2,145,799,463	1.03	1,367,070	13.48	0.80	1,712,502	711,530	1.01
Northern States Power Co (Minnesota)	2010	2,214,408,096	1.03	1,363,421	13.43	0.80	1,714,665	712,987	1.00
Northern States Power Co (Minnesota)	2011	2,377,390,702	1.07	1,399,830	13.75	0.81	1,718,617	715,214	1.00
Northern States Power Co (Wisconsin)	2007	347,087,295		255,886	7.08	0.42	610,307	248,772	
Northern States Power Co (Wisconsin)	2008	381,648,345	1.10	259,581	7.21	0.43	607,656	247,712	1.00
Northern States Power Co (Wisconsin)	2009	390,538,557	1.02	261,039	7.18	0.43	613,685	250,147	1.01
Northern States Power Co (Wisconsin)	2010	419,721,024	1.07	260,458	7.19	0.43	611,827	249,579	1.00
Northern States Power Co (Wisconsin)	2011	467,125,536	1.11	250,133	6.87	0.41	614,549	250,819	1.00
NorthWestern Corp	2007	631,212,273		385,724	12.41	0.73	524,809	216,299	
NorthWestern Corp	2008	634,567,404	1.01	391,049	12.50	0.74	528,060	219,000	1.01
NorthWestern Corp	2009	639,663,839	1.01	394,869	12.46	0.74	535,281	221,939	1.01
NorthWestern Corp	2010	666,497,238	1.04	397,760	14.46	0.86	464,372	193,829	0.87
NorthWestern Corp	2011	706,979,160	1.06	400,281	14.50	0.86	466,047	194,982	1.01

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Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
NSTAR Electric Co	2007	2,241,925,050		1,138,361	33.06	1.96	581,378	255,451	
NSTAR Electric Co	2008	2,374,876,729	1.06	1,143,367	32.73	1.94	589,819	259,157	1.01
NSTAR Electric Co	2009	2,486,531,894	1.05	1,151,067	32.89	1.95	591,004	260,639	1.01
NSTAR Electric Co	2010	2,436,630,196	0.98	1,156,909	32.12	1.90	608,245	267,921	1.03
NSTAR Electric Co	2011	2,484,759,418	1.02	1,163,077	35.33	2.09	555,881	246,996	0.92
Ohio Edison Co	2007	966,624,989		1,040,663	16.62	0.98	1,057,343	428,461	
Ohio Edison Co	2008	1,053,494,703	1.09	1,040,519	16.60	0.98	1,058,728	428,883	1.00
Ohio Edison Co	2009	1,087,581,439	1.03	1,037,999	16.53	0.98	1,060,113	428,610	1.00
Ohio Edison Co	2010	1,259,409,883	1.16	1,036,982	16.50	0.98	1,061,497	429,365	1.00
Ohio Edison Co	2011	1,194,136,352	0.95	1,034,535	16.44	0.97	1,062,882	429,887	1.00
Ohio Power Co	2007	2,381,815,321		1,456,742	31.50	1.87	780,799	332,468	
Ohio Power Co	2008	2,449,229,215	1.03	1,458,714	31.52	1.87	781,494	332,316	1.00
Ohio Power Co	2009	2,681,476,082	1.09	1,459,561	31.51	1.87	782,058	332,856	1.00
Ohio Power Co	2010	2,711,084,433	1.01	1,458,753	31.40	1.86	784,361	334,226	1.00
Ohio Power Co	2011	2,773,988,162	1.02	1,459,991	31.46	1.86	783,730	333,587	1.00
Oklahoma Gas & Electric Co	2007	1,489,468,129		759,624	17.75	1.05	722,704	302,375	
Oklahoma Gas & Electric Co	2008	1,608,309,804	1.08	766,935	17.69	1.05	732,176	306,188	1.01
Oklahoma Gas & Electric Co	2009	1,796,922,441	1.12	773,945	17.38	1.03	751,770	314,368	1.03
Oklahoma Gas & Electric Co	2010	2,004,201,748	1.12	780,230	17.40	1.03	757,384	317,558	1.01
Oklahoma Gas & Electric Co	2011	2,175,601,365	1.09	786,569	16.46	0.97	806,844	337,354	1.06
Oncor Electric Delivery	2007	5,306,246,583		3,077,913	26.34	1.56	1,973,409	838,762	
Oncor Electric Delivery	2008	5,708,326,155	1.08	3,109,701	26.45	1.57	1,985,525	844,144	1.01
Oncor Electric Delivery	2009	5,705,012,110	1.00	3,135,675	26.61	1.58	1,990,082	848,000	1.00
Oncor Electric Delivery	2010	6,211,774,539	1.09	3,160,851	26.70	1.58	1,998,746	853,390	1.01
Oncor Electric Delivery	2011	6,594,333,316	1.06	3,189,759	26.85	1.59	2,005,678	857,976	1.01
Orange & Rockland Utilities Inc	2007	298,114,455		221,454	38.66	2.29	96,714	42,853	
Orange & Rockland Utilities Inc	2008	294,987,885	0.99	222,343	38.17	2.26	98,352	43,378	1.01
Orange & Rockland Utilities Inc	2009	305,253,826	1.03	223,339	37.38	2.21	100,902	44,398	1.02
Orange & Rockland Utilities Inc	2010	311,771,652	1.02	223,911	37.22	2.20	101,594	44,694	1.01
Orange & Rockland Utilities Inc	2011	369,905,994	1.19	224,611	37.01	2.19	102,492	45,116	1.01
Pacific Gas & Electric Co	2007	8,367,764,702		5,190,978	32.61	1.93	2,688,019	1,123,855	
Pacific Gas & Electric Co	2008	8,513,388,201	1.02	5,278,738	33.06	1.96	2,696,443	1,128,700	1.00
Pacific Gas & Electric Co	2009	9,448,318,473	1.11	5,224,258	32.69	1.94	2,698,870	1,130,994	1.00
Pacific Gas & Electric Co	2010	10,561,395,734	1.12	5,212,599	32.59	1.93	2,700,552	1,131,939	1.00
Pacific Gas & Electric Co	2011	11,166,100,662	1.06	5,248,291	32.88	1.95	2,695,305	1,131,471	1.00
PECO Energy Co	2007	2,611,741,145		1,555,342	52.88	3.13	496,666	216,410	
PECO Energy Co	2008	2,649,516,508	1.01	1,567,250	52.50	3.11	504,125	219,748	1.02
PECO Energy Co	2009	2,815,956,612	1.06	1,564,433	52.17	3.09	506,337	220,705	1.00
PECO Energy Co	2010	2,922,172,022	1.04	1,566,872	52.16	3.09	507,215	221,556	1.00
PECO Energy Co	2011	2,609,372,420	0.89	1,573,976	68.28	4.04	389,231	177,600	0.80
Pennsylvania Electric Co	2007	934,423,884		588,888	20.02	1.19	496,651	206,547	
Pennsylvania Electric Co	2008	1,011,003,922	1.08	589,034	19.95	1.18	498,581	207,290	1.00
Pennsylvania Electric Co	2009	1,035,174,342	1.02	589,218	19.89	1.18	500,304	208,054	1.00
Pennsylvania Electric Co	2010	934,359,889	0.90	589,869	19.84	1.17	502,026	208,713	1.00
Pennsylvania Electric Co	2011	1,259,389,487	1.35	589,668	19.77	1.17	503,749	209,526	1.00

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Pennsylvania Power Co	2007	166,947,043		158,989	11.91	0.71	225,371	91,192	
Pennsylvania Power Co	2008	192,823,033	1.15	159,347	11.91	0.71	225,878	91,549	1.00
Pennsylvania Power Co	2009	211,457,291	1.10	159,558	11.90	0.70	226,385	91,695	1.00
Pennsylvania Power Co	2010	224,991,660	1.06	159,886	11.90	0.70	226,891	91,925	1.00
Pennsylvania Power Co	2011	220,678,240	0.98	160,250	11.90	0.70	227,398	92,128	1.00
Potomac Edison Co (The)	2007	607,544,776		475,029	20.38	1.21	393,650	165,707	
Potomac Edison Co (The)	2008	627,523,343	1.03	480,217	20.24	1.20	400,681	167,810	1.01
Potomac Edison Co (The)	2009	704,790,109	1.12	483,414	19.25	1.14	424,080	178,065	1.06
Potomac Edison Co (The)	2010	585,049,795	0.83	424,657	23.29	1.38	307,870	129,786	0.73
Potomac Edison Co (The)	2011	627,470,757	1.07	388,819	19.19	1.14	342,152	144,869	1.12
PPL Electric Utilities Corp	2007	2,222,736,491		1,385,122	34.62	2.05	675,647	303,844	
PPL Electric Utilities Corp	2008	2,235,736,840	1.01	1,392,482	34.61	2.05	679,462	305,889	1.01
PPL Electric Utilities Corp	2009	2,273,263,730	1.02	1,397,772	34.63	2.05	681,575	307,241	1.00
PPL Electric Utilities Corp	2010	1,967,676,787	0.87	1,401,699	34.62	2.05	683,710	308,819	1.01
PPL Electric Utilities Corp	2011	2,182,991,328	1.11	1,403,931	31.47	1.86	753,243	337,367	1.09
Progress Energy Carolinas	2007	2,894,247,849		1,423,785	20.09	1.19	1,196,503	536,831	
Progress Energy Carolinas	2008	2,941,051,820	1.02	1,447,449	20.42	1.21	1,196,739	537,275	1.00
Progress Energy Carolinas	2009	2,943,479,925	1.00	1,461,898	20.02	1.19	1,233,073	553,418	1.03
Progress Energy Carolinas	2010	3,015,623,842	1.02	1,438,911	19.70	1.17	1,233,095	543,518	0.98
Progress Energy Carolinas	2011	3,087,329,848	1.02	1,445,176	19.75	1.17	1,235,435	544,719	1.00
Progress Energy Florida	2007	2,475,711,178		1,632,451	45.49	2.69	605,946	264,308	
Progress Energy Florida	2008	2,497,972,208	1.01	1,638,935	45.62	2.70	606,596	265,901	1.01
Progress Energy Florida	2009	3,113,364,741	1.25	1,630,195	45.35	2.69	606,948	266,814	1.00
Progress Energy Florida	2010	3,079,224,545	0.99	1,640,833	45.55	2.70	608,276	268,659	1.01
Progress Energy Florida	2011	2,924,431,113	0.95	1,642,161	45.49	2.69	609,551	269,709	1.00
Public Service Co of Colorado	2007	2,129,731,478		1,355,763	15.18	0.90	1,508,584	615,841	
Public Service Co of Colorado	2008	2,262,455,584	1.06	1,358,070	15.10	0.89	1,518,414	620,100	1.01
Public Service Co of Colorado	2009	2,331,171,439	1.03	1,369,250	15.15	0.90	1,526,127	625,200	1.01
Public Service Co of Colorado	2010	2,576,898,902	1.11	1,366,177	15.00	0.89	1,537,521	630,454	1.01
Public Service Co of Colorado	2011	2,792,599,802	1.08	1,372,919	14.89	0.88	1,556,985	639,415	1.01
Public Service Co of New Mexico	2007	490,596,832		489,410	34.03	2.02	242,828	104,464	
Public Service Co of New Mexico	2008	550,119,180	1.12	495,284	34.03	2.02	245,754	105,689	1.01
Public Service Co of New Mexico	2009	571,676,555	1.04	495,043	33.89	2.01	246,684	106,061	1.00
Public Service Co of New Mexico	2010	640,373,488	1.12	501,787	34.53	2.05	245,350	105,575	1.00
Public Service Co of New Mexico	2011	676,511,355	1.06	503,963	34.61	2.05	245,891	105,992	1.00
Public Service Co of Oklahoma	2007	650,675,892		522,422	24.68	1.46	357,503	152,461	
Public Service Co of Oklahoma	2008	1,104,345,007	1.70	525,804	24.81	1.47	357,870	153,171	1.00
Public Service Co of Oklahoma	2009	1,072,778,974	0.97	529,271	24.77	1.47	360,768	154,484	1.01
Public Service Co of Oklahoma	2010	1,113,285,687	1.04	531,850	25.18	1.49	356,727	152,564	0.99
Public Service Co of Oklahoma	2011	1,229,091,890	1.10	532,396	25.25	1.50	355,999	152,672	1.00
Public Service Electric & Gas Co	2007	3,054,955,363		2,099,626	96.47	5.71	367,499	166,412	
Public Service Electric & Gas Co	2008	3,128,015,739	1.02	2,110,003	91.09	5.39	391,147	176,238	1.06
Public Service Electric & Gas Co	2009	3,283,269,324	1.05	2,132,180	91.68	5.43	392,710	176,961	1.00
Public Service Electric & Gas Co	2010	3,767,067,278	1.15	2,154,826	91.44	5.42	397,927	179,405	1.01
Public Service Electric & Gas Co	2011	4,341,630,529	1.15	2,157,075	91.58	5.42	397,714	179,565	1.00

Schedule 2: Electric Utility Data Base

A	B	AB	AC	AD	AE	AF	AG	AH	AI
Formula:		J*(1-X)+(X*W)	%Δ in AB		AD/(Y+Z)	Base ≈ 16.89	AD/AF	(AG*0.4)+(AA*0.6)	%Δ in AH
Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
San Diego Gas & Electric Co	2007	2,043,634,461		1,355,136	56.58	3.35	404,442	172,458	
San Diego Gas & Electric Co	2008	2,206,731,531	1.08	1,362,847	56.53	3.35	407,127	173,851	1.01
San Diego Gas & Electric Co	2009	2,376,627,904	1.08	1,370,621	56.60	3.35	408,929	174,773	1.01
San Diego Gas & Electric Co	2010	2,553,738,913	1.07	1,378,469	56.76	3.36	410,074	174,962	1.00
San Diego Gas & Electric Co	2011	2,809,124,460	1.10	1,385,785	56.83	3.37	411,745	175,673	1.00
South Carolina Electric & Gas Co	2007	1,639,369,621		633,587	23.10	1.37	463,215	200,316	
South Carolina Electric & Gas Co	2008	1,779,865,405	1.09	646,537	23.17	1.37	471,185	203,501	1.02
South Carolina Electric & Gas Co	2009	1,932,030,682	1.09	653,193	23.19	1.37	475,549	205,390	1.01
South Carolina Electric & Gas Co	2010	2,025,279,899	1.05	658,960	23.25	1.38	478,630	207,138	1.01
South Carolina Electric & Gas Co	2011	2,154,900,796	1.06	663,440	23.28	1.38	481,288	208,679	1.01
Southern California Edison Co	2007	7,819,400,902		4,836,804	39.07	2.31	2,090,229	887,385	
Southern California Edison Co	2008	6,101,485,815	0.78	4,860,669	39.27	2.33	2,089,881	888,532	1.00
Southern California Edison Co	2009	9,358,226,731	1.53	4,874,890	38.76	2.30	2,123,886	905,704	1.02
Southern California Edison Co	2010	9,971,612,820	1.07	4,900,352	42.33	2.51	1,955,025	841,349	0.93
Southern California Edison Co	2011	9,864,367,485	0.99	4,921,250	42.69	2.53	1,946,738	840,502	1.00
Southern Indiana Gas & Electric Co	2007	320,140,093		146,477	20.87	1.24	118,492	52,487	
Southern Indiana Gas & Electric Co	2008	337,598,182	1.05	146,340	20.55	1.22	120,274	52,458	1.00
Southern Indiana Gas & Electric Co	2009	386,478,972	1.14	145,945	20.47	1.21	120,405	52,641	1.00
Southern Indiana Gas & Electric Co	2010	453,826,135	1.17	146,240	20.21	1.20	122,175	53,564	1.02
Southern Indiana Gas & Electric Co	2011	464,449,603	1.02	146,136	20.12	1.19	122,676	53,768	1.00
Southwestern Electric Power Co	2007	969,989,690		464,808	21.77	1.29	360,519	157,177	
Southwestern Electric Power Co	2008	1,062,331,882	1.10	469,278	21.84	1.29	362,905	158,570	1.01
Southwestern Electric Power Co	2009	1,109,251,273	1.04	472,392	21.97	1.30	363,000	158,972	1.00
Southwestern Electric Power Co	2010	1,234,020,174	1.11	486,174	22.34	1.32	367,416	160,965	1.01
Southwestern Electric Power Co	2011	1,317,247,990	1.07	521,614	23.84	1.41	369,508	161,778	1.01
Southwestern Public Service Co	2007	776,740,544		391,546	8.13	0.48	813,252	334,984	
Southwestern Public Service Co	2008	809,257,603	1.04	400,064	7.96	0.47	848,931	349,507	1.04
Southwestern Public Service Co	2009	935,156,524	1.16	410,438	8.10	0.48	855,541	352,841	1.01
Southwestern Public Service Co	2010	928,105,437	0.99	393,461	8.06	0.48	824,201	341,163	0.97
Southwestern Public Service Co	2011	1,035,900,254	1.12	376,196	7.64	0.45	831,052	345,588	1.01
Tampa Electric Co	2007	1,107,517,642		666,354	43.44	2.57	259,018	112,169	
Tampa Electric Co	2008	1,104,523,905	1.00	667,266	54.69	3.24	206,010	90,904	0.81
Tampa Electric Co	2009	1,245,998,818	1.13	666,747	54.65	3.24	206,019	91,138	1.00
Tampa Electric Co	2010	1,284,527,060	1.03	670,991	54.46	3.23	208,030	92,014	1.01
Tampa Electric Co	2011	1,327,589,185	1.03	675,799	54.83	3.25	208,136	92,077	1.00
Toledo Edison Co (The)	2007	324,630,633		313,416	17.60	1.04	300,779	121,738	
Toledo Edison Co (The)	2008	341,359,721	1.05	312,644	17.55	1.04	300,795	122,049	1.00
Toledo Edison Co (The)	2009	347,283,493	1.02	310,726	17.44	1.03	300,812	121,785	1.00
Toledo Edison Co (The)	2010	367,264,739	1.06	309,901	17.40	1.03	300,829	121,871	1.00
Toledo Edison Co (The)	2011	358,474,798	0.98	309,021	17.34	1.03	300,846	121,906	1.00
Tucson Electric Power Co	2007	618,196,091		395,098	42.44	2.51	157,194	71,021	
Tucson Electric Power Co	2008	610,929,228	0.99	398,609	42.22	2.50	159,429	72,131	1.02
Tucson Electric Power Co	2009	718,549,621	1.18	401,140	42.64	2.53	158,863	71,904	1.00
Tucson Electric Power Co	2010	778,998,197	1.08	402,361	42.61	2.52	159,467	72,821	1.01
Tucson Electric Power Co	2011	957,360,802	1.23	403,377	42.52	2.52	160,210	72,831	1.00

Schedule 2: Electric Utility Data Base

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Utility Name	Year	Cost Change	% Cost Change	Total Electricity Customers	Density	Density Index	Customers Adjusted for Density	Output 40/60 weight	%Change in Output 40/60
Unitil Energy Systems	2007	67,903,809		75,442	37.59	2.23	33,890	13,705	
Unitil Energy Systems	2008	69,432,476	1.02	75,948	37.49	2.22	34,211	13,833	1.01
Unitil Energy Systems	2009	74,111,815	1.07	76,085	37.42	2.22	34,329	13,884	1.00
Unitil Energy Systems	2010	80,592,911	1.09	76,124	38.31	2.27	33,552	13,573	0.98
Unitil Energy Systems	2011	86,635,296	1.07	76,212	49.04	2.90	26,241	10,658	0.79
UNS Electric Inc	2007	85,956,618		89,472	23.44	1.39	64,456	26,499	
UNS Electric Inc	2008	92,769,989	1.08	89,989	23.27	1.38	65,305	26,862	1.01
UNS Electric Inc	2009	103,185,832	1.11	90,100	23.10	1.37	65,870	27,162	1.01
UNS Electric Inc	2010	110,061,025	1.07	90,802	23.13	1.37	66,299	27,345	1.01
UNS Electric Inc	2011	130,550,717	1.19	91,255	23.13	1.37	66,626	27,547	1.01
Virginia Electric & Power Co	2007	4,299,138,728		2,362,324	38.67	2.29	1,031,582	452,938	
Virginia Electric & Power Co	2008	4,706,072,759	1.09	2,386,213	38.43	2.28	1,048,580	460,260	1.02
Virginia Electric & Power Co	2009	4,473,267,754	0.95	2,403,563	38.70	2.29	1,048,749	461,964	1.00
Virginia Electric & Power Co	2010	5,458,511,907	1.22	2,422,975	38.48	2.28	1,063,281	468,939	1.02
Virginia Electric & Power Co	2011	6,427,391,307	1.18	2,438,231	38.61	2.29	1,066,464	471,516	1.01
West Penn Power Co	2007	632,684,389		711,055	26.21	1.55	458,189	192,450	
West Penn Power Co	2008	704,145,059	1.11	713,406	26.43	1.57	455,805	191,645	1.00
West Penn Power Co	2009	768,353,151	1.09	714,971	24.68	1.46	489,256	202,958	1.06
West Penn Power Co	2010	764,016,174	0.99	716,113	26.18	1.55	461,943	192,893	0.95
West Penn Power Co	2011	826,935,788	1.08	717,275	33.02	1.96	366,774	155,086	0.80
Westar Energy Inc	2007	616,327,030		362,571	11.66	0.69	525,023	217,365	
Westar Energy Inc	2008	671,906,018	1.09	364,788	11.60	0.69	531,235	220,332	1.01
Westar Energy Inc	2009	755,987,839	1.13	367,763	11.63	0.69	534,127	221,637	1.01
Westar Energy Inc	2010	904,390,885	1.20	368,670	11.61	0.69	536,433	222,430	1.00
Westar Energy Inc	2011	953,863,332	1.05	369,168	11.61	0.69	537,113	227,929	1.02
Wheeling Power Co	2007	67,217,686		41,332	24.26	1.44	28,763	12,050	
Wheeling Power Co	2008	72,215,778	1.07	41,334	24.24	1.44	28,797	12,037	1.00
Wheeling Power Co	2009	80,437,430	1.11	41,225	24.17	1.43	28,796	12,037	1.00
Wheeling Power Co	2010	77,201,527	0.96	41,146	24.10	1.43	28,834	12,102	1.01
Wheeling Power Co	2011	98,885,421	1.28	41,099	23.80	1.41	29,155	12,234	1.01
Wisconsin Electric Power Co	2007	1,450,346,835		1,105,500	24.85	1.47	751,256	341,881	
Wisconsin Electric Power Co	2008	1,074,312,849	0.74	1,111,820	24.48	1.45	766,960	348,438	1.02
Wisconsin Electric Power Co	2009	1,321,065,584	1.23	1,115,523	24.40	1.45	771,941	351,077	1.01
Wisconsin Electric Power Co	2010	1,355,655,761	1.03	1,118,722	24.67	1.46	765,660	352,793	1.00
Wisconsin Electric Power Co	2011	1,475,482,576	1.09	1,120,990	24.68	1.46	766,825	351,327	1.00
Wisconsin Power & Light Co	2007	594,206,572		450,470	21.53	1.28	353,271	143,996	
Wisconsin Power & Light Co	2008	633,371,276	1.07	453,957	21.54	1.28	355,888	145,166	1.01
Wisconsin Power & Light Co	2009	703,326,135	1.11	455,870	21.61	1.28	356,294	145,435	1.00
Wisconsin Power & Light Co	2010	800,092,457	1.14	456,495	21.47	1.27	359,046	146,676	1.01
Wisconsin Power & Light Co	2011	861,958,410	1.08	458,116	21.48	1.27	360,127	147,220	1.00
Wisconsin Public Service Corp	2007	375,529,414		430,425	20.02	1.19	362,980	150,278	
Wisconsin Public Service Corp	2008	402,588,690	1.07	433,712	20.17	1.19	363,048	150,429	1.00
Wisconsin Public Service Corp	2009	407,660,896	1.01	435,770	20.27	1.20	363,048	150,537	1.00
Wisconsin Public Service Corp	2010	416,875,364	1.02	437,908	20.37	1.21	363,048	150,542	1.00
Wisconsin Public Service Corp	2011	416,358,757	1.00	439,636	20.26	1.20	366,425	151,865	1.01

Schedule 2: Electric Utility Data Base

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Formula:		**AI-AC**	**(AG*0.6)+(AA*0.4)**	**%Δ in AK**	**AL-AC**	**%Δ in AG**	**AN-AC**	**%Δ in AA**	**AP-AC**	**%Δ in Y+Z**	**AR-AC**
Utility Name	**Year**	**Composite TFP**	**Output 60/40 weight**	**% Change in Output 60/40**	**Composite TFP**	**%Change in Customers**	**Customer TFP**	**% Change in Capacity**	**Capacity TFP**	**% Change Miles of Line**	**Miles TFP**
ALLETE Inc	2007		88,155								
ALLETE Inc	2008	-0.0321	87,232	0.99	-0.0358	0.986275288	-0.03905	1.063694268	0.03837	0.986275288	-0.03905
ALLETE Inc	2009	-0.1804	91,729	1.05	-0.1762	1.05523706	-0.17253	0.973612098	-0.25415	1.05523706	-0.17253
ALLETE Inc	2010	-0.0787	91,543	1.00	-0.0849	0.992498009	-0.09038	1.123319087	0.04044	0.992498009	-0.09038
ALLETE Inc	2011	-0.0523	92,896	1.01	-0.0517	1.015386849	-0.05107	1.002598367	-0.06386	1.015386849	-0.05107
Ameren Missouri	2007		373,073								
Ameren Missouri	2008	-0.0451	378,189	1.01	-0.0452	1.013644029	-0.04524	1.015103428	-0.04378	1.013644029	-0.04524
Ameren Missouri	2009	-0.0723	379,030	1.00	-0.0730	1.001517415	-0.07376	1.016320014	-0.05895	1.001517415	-0.07376
Ameren Missouri	2010	-0.0900	379,434	1.00	-0.0905	1.000575823	-0.09099	1.010712571	-0.08086	1.000575823	-0.09099
Ameren Missouri	2011	-0.0310	378,409	1.00	-0.0198	1.007323618	-0.00979	0.802029142	-0.21508	1.007323618	-0.00979
Appalachian Power Co	2007		542,023								
Appalachian Power Co	2008	-0.0703	543,383	1.00	-0.0690	1.003645932	-0.06781	0.967094189	-0.10437	1.003645932	-0.06781
Appalachian Power Co	2009	-0.0412	544,668	1.00	-0.0410	1.002479716	-0.04092	0.998676243	-0.04472	1.002479716	-0.04092
Appalachian Power Co	2010	-0.0347	545,498	1.00	-0.0347	1.001572546	-0.03464	0.999950907	-0.03626	1.001572546	-0.03464
Appalachian Power Co	2011	-0.0519	546,482	1.00	-0.0523	1.001503644	-0.05259	1.011537423	-0.04256	1.001503644	-0.05259
Arizona Public Service Co	2007		364,621								
Arizona Public Service Co	2008	-0.0337	356,763	0.98	-0.0316	0.980299163	-0.02977	0.936718992	-0.07335	0.980299163	-0.02977
Arizona Public Service Co	2009	-0.0358	364,325	1.02	-0.0365	1.020574845	-0.03715	1.03585899	-0.02186	1.020574845	-0.03715
Arizona Public Service Co	2010	-0.0730	363,856	1.00	-0.0740	0.997865157	-0.07481	1.018386462	-0.05429	0.997865157	-0.07481
Arizona Public Service Co	2011	-0.0279	368,707	1.01	-0.0289	1.012404802	-0.02985	1.034462937	-0.00779	1.012404802	-0.02985
Avista Corp	2007		204,624								
Avista Corp	2008	-0.0576	208,256	1.02	-0.0570	1.018292989	-0.05641	0.973266364	-0.10144	1.018292989	-0.05641
Avista Corp	2009	-0.1975	205,311	0.99	-0.1982	0.985283985	-0.19880	1.034959214	-0.14912	0.985283985	-0.19880
Avista Corp	2010	0.0704	209,257	1.02	0.0708	1.019531445	0.07107	0.993887727	0.04543	1.019531445	0.07107
Avista Corp	2011	-0.0469	210,260	1.00	-0.0468	1.004899559	-0.04664	0.995792199	-0.05575	1.004899559	-0.04664
Baltimore Gas & Electric Co	2007		265,088								
Baltimore Gas & Electric Co	2008	0.0780	270,530	1.02	0.0775	1.020067604	0.07702	1.029686067	0.08663	1.020067604	0.07702
Baltimore Gas & Electric Co	2009	-0.1546	273,211	1.01	-0.1647	1.000928164	-0.17367	1.187442432	0.01284	1.000928164	-0.17367
Baltimore Gas & Electric Co	2010	-0.0762	275,265	1.01	-0.0702	1.012995605	-0.06469	0.916276665	-0.16141	1.012995605	-0.06469
Baltimore Gas & Electric Co	2011	-0.0474	275,668	1.00	-0.0515	0.997777646	-0.05523	1.069334312	0.01633	0.997777646	-0.05523
CenterPoint Energy Houston Electric LLC	2007		528,657								
CenterPoint Energy Houston Electric LLC	2008	0.0141	537,912	1.02	0.0145	1.017798606	0.01474	1.010160914	0.00711	1.017798606	0.01474
CenterPoint Energy Houston Electric LLC	2009	-0.0103	543,220	1.01	-0.0099	1.010143477	-0.00967	1.002876712	-0.01694	1.010143477	-0.00967
CenterPoint Energy Houston Electric LLC	2010	-0.0121	548,052	1.01	-0.0129	1.008245068	-0.01354	1.025464905	0.00368	1.008245068	-0.01354
CenterPoint Energy Houston Electric LLC	2011	-0.0317	553,334	1.01	-0.0311	1.010122329	-0.03062	0.99752626	-0.04322	1.010122329	-0.03062
Central Hudson Gas & Electric Corp	2007		102,610								
Central Hudson Gas & Electric Corp	2008	-0.0292	104,054	1.01	-0.0312	1.01235565	-0.03296	1.113091158	0.06777	1.01235565	-0.03296
Central Hudson Gas & Electric Corp	2009	-0.0782	104,427	1.00	-0.0764	1.005060548	-0.07495	0.926108374	-0.15390	1.005060548	-0.07495
Central Hudson Gas & Electric Corp	2010	-0.0844	105,483	1.01	-0.0847	1.009872682	-0.08493	1.02393617	-0.07087	1.009872682	-0.08493
Central Hudson Gas & Electric Corp	2011	-0.1489	96,358	0.91	-0.1507	0.911974433	-0.15222	0.998701299	-0.06549	0.911974433	-0.15222
Central Vermont Public Service Corp	2007		95,992								
Central Vermont Public Service Corp	2008	-0.0324	97,118	1.01	-0.0325	1.011606445	-0.03266	1.040604344	-0.00366	1.011606445	-0.03266
Central Vermont Public Service Corp	2009	-0.0641	97,332	1.00	-0.0641	1.002209141	-0.06407	1	-0.06628	1.002209141	-0.06407
Central Vermont Public Service Corp	2010	-0.0027	97,617	1.00	-0.0029	1.00280344	-0.00300	1.031760436	0.02595	1.00280344	-0.00300
Central Vermont Public Service Corp	2011	-0.0709	98,204	1.01	-0.0709	1.006034373	-0.07084	1.000879507	-0.07599	1.006034373	-0.07084

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Utility Name	**Year**	**Composite TFP**	**Output 60/40 weight**	**% Change in Output 60/40**	**Composite TFP**	**%Change in Customers**	**Customer TFP**	**% Change in Capacity**	**Capacity TFP**	**% Change Miles of Line**	**Miles TFP**
Chugach Electric Association Inc	2007		24,211								
Chugach Electric Association Inc	2008	0.0399	24,359	1.01	0.0391	1.005384256	0.03834	1.016437684	0.04940	1.005384256	0.03834
Chugach Electric Association Inc	2009	0.0158	24,434	1.00	0.0160	1.003298047	0.01627	1	0.01297	1.003298047	0.01627
Chugach Electric Association Inc	2010	-0.0644	24,505	1.00	-0.0642	1.003113727	-0.06396	1	-0.06708	1.003113727	-0.06396
Chugach Electric Association Inc	2011	0.1107	24,454	1.00	0.1106	0.997782813	0.11043	1	0.11265	0.997782813	0.11043
CLECO Power LLC	2007		132,896								
CLECO Power LLC	2008	-0.0702	133,785	1.01	-0.0705	1.006417144	-0.07081	1.014123581	-0.06310	1.006417144	-0.07081
CLECO Power LLC	2009	-0.0360	134,629	1.01	-0.0358	1.006443006	-0.03568	1.00265274	-0.03947	1.006443006	-0.03568
CLECO Power LLC	2010	-0.2272	135,693	1.01	-0.2270	1.008121438	-0.22676	1.002149649	-0.23274	1.008121438	-0.22676
CLECO Power LLC	2011	-0.0978	137,327	1.01	-0.1023	1.008104019	-0.10623	1.11830707	0.00397	1.008104019	-0.10623
Cleveland Electric Illuminating Co (The)	2007		360,052								
Cleveland Electric Illuminating Co (The)	2008	-0.0594	360,474	1.00	-0.0594	1.00119223	-0.05933	0.998597118	-0.06193	1.00119223	-0.05933
Cleveland Electric Illuminating Co (The)	2009	-0.0239	361,655	1.00	-0.0264	1.00119081	-0.02853	1.24137931	0.21166	1.00119081	-0.02853
Cleveland Electric Illuminating Co (The)	2010	-0.0935	362,061	1.00	-0.0935	1.001189394	-0.09339	0.994855967	-0.09972	1.001189394	-0.09339
Cleveland Electric Illuminating Co (The)	2011	0.0019	362,219	1.00	0.0018	1.000322452	0.00165	1.011168563	0.01249	1.000322452	0.00165
Commonwealth Edison Co	2007		883,941								
Commonwealth Edison Co	2008	-0.0667	911,301	1.03	-0.0665	1.031133092	-0.06630	1.026006463	-0.07142	1.031133092	-0.06630
Commonwealth Edison Co	2009	-0.2482	736,124	0.81	-0.2562	0.800831518	-0.26319	0.999272207	-0.06475	0.800831518	-0.26319
Commonwealth Edison Co	2010	-0.0606	748,469	1.02	-0.0598	1.017476584	-0.05905	1.001130156	-0.07540	1.017476584	-0.05905
Commonwealth Edison Co	2011	-0.0164	750,174	1.00	-0.0169	1.001822635	-0.01737	1.012530574	-0.00666	1.001822635	-0.01737
Consolidated Edison Co of New York Inc	2007		1,345,438								
Consolidated Edison Co of New York Inc	2008	-0.0921	1,356,555	1.01	-0.0921	1.008216461	-0.09216	1.011632237	-0.08874	1.008216461	-0.09216
Consolidated Edison Co of New York Inc	2009	-0.0537	1,364,951	1.01	-0.0537	1.006207359	-0.05371	1.004850585	-0.05506	1.006207359	-0.05371
Consolidated Edison Co of New York Inc	2010	-0.0612	1,372,352	1.01	-0.0612	1.005411599	-0.06117	1.006184812	-0.06040	1.005411599	-0.06117
Consolidated Edison Co of New York Inc	2011	-0.0714	1,374,395	1.00	-0.0698	1.0027992	-0.06853	0.906513032	-0.16482	1.0027992	-0.06853
Consumers Energy Co	2007		719,122								
Consumers Energy Co	2008	-0.0937	721,855	1.00	-0.0949	1.002854737	-0.09582	1.07583956	-0.02283	1.002854737	-0.09582
Consumers Energy Co	2009	-0.0119	722,250	1.00	-0.0091	1.00288931	-0.00675	0.834144978	-0.17549	1.00288931	-0.00675
Consumers Energy Co	2010	-0.0570	723,939	1.00	-0.0563	1.002880985	-0.05579	0.956022396	-0.10265	1.002880985	-0.05579
Consumers Energy Co	2011	-0.0729	724,977	1.00	-0.0734	1.001047195	-0.07378	1.036089699	-0.03874	1.001047195	-0.07378
Detroit Edison Co (The)	2007		477,496								
Detroit Edison Co (The)	2008	0.0259	475,498	1.00	0.0257	0.995646279	0.02556	1.001734242	0.03164	0.995646279	0.02556
Detroit Edison Co (The)	2009	-0.1536	477,344	1.00	-0.1533	1.004137282	-0.15307	0.995074921	-0.16213	1.004137282	-0.15307
Detroit Edison Co (The)	2010	0.0457	478,051	1.00	0.0457	1.001440008	0.04566	1.002879683	0.04710	1.001440008	0.04566
Detroit Edison Co (The)	2011	-0.0935	481,991	1.01	-0.0934	1.008372525	-0.09324	1.00370891	-0.09790	1.008372525	-0.09324
Duke Energy Carolinas	2007		1,123,070								
Duke Energy Carolinas	2008	-0.0079	1,133,536	1.01	-0.0078	1.009411976	-0.00767	1.006567034	-0.01052	1.009411976	-0.00767
Duke Energy Carolinas	2009	-0.0232	1,144,009	1.01	-0.0231	1.009311375	-0.02307	1.007109416	-0.02527	1.009311375	-0.02307
Duke Energy Carolinas	2010	-0.0104	1,151,249	1.01	-0.0102	1.006527994	-0.01000	1.000376636	-0.01615	1.006527994	-0.01000
Duke Energy Carolinas	2011	-0.0749	1,151,725	1.00	-0.0749	1.000359223	-0.07498	1.002043824	-0.07329	1.000359223	-0.07498
Duke Energy Indiana	2007		368,505								
Duke Energy Indiana	2008	-0.0103	378,865	1.03	-0.0100	1.028413923	-0.00966	1.017513411	-0.02056	1.028413923	-0.00966
Duke Energy Indiana	2009	-0.0261	382,782	1.01	-0.0260	1.010453576	-0.02585	1.006202512	-0.03010	1.010453576	-0.02585
Duke Energy Indiana	2010	-0.0484	378,525	0.99	-0.0479	0.989242941	-0.04758	0.975843736	-0.06098	0.989242941	-0.04758
Duke Energy Indiana	2011	-0.0170	377,511	1.00	-0.0177	0.996752009	-0.01824	1.017963599	0.00297	0.996752009	-0.01824

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Utility Name	Year	Composite TFP	Output 60/40 weight	% Change in Output 60/40	Composite TFP	%Change in Customers	Customer TFP	% Change in Capacity	Capacity TFP	% Change Miles of Line	Miles TFP
Duke Energy Ohio	2007		243,729								
Duke Energy Ohio	2008	-0.0183	244,760	1.00	-0.0224	1.000195649	-0.02642	1.041749133	0.01513	1.000195649	-0.02642
Duke Energy Ohio	2009	-0.0642	244,996	1.00	-0.0648	1.000358083	-0.06540	1.006381631	-0.05937	1.000358083	-0.06540
Duke Energy Ohio	2010	-0.0441	245,010	1.00	-0.0441	1.000022545	-0.04416	1.000354976	-0.04383	1.000022545	-0.04416
Duke Energy Ohio	2011	0.0942	246,048	1.00	0.0946	1.004676316	0.09505	1.00035485	0.09073	1.004676316	0.09505
Empire District Electric Co (The)	2007		84,464								
Empire District Electric Co (The)	2008	-0.0424	85,216	1.01	-0.0424	1.008878247	-0.04241	1.009792627	-0.04150	1.008878247	-0.04241
Empire District Electric Co (The)	2009	0.0004	85,773	1.01	-0.0003	1.005976863	-0.00083	1.028522533	0.02172	1.005976863	-0.00083
Empire District Electric Co (The)	2010	-0.0355	86,031	1.00	-0.0356	1.002974917	-0.03563	1.004621926	-0.03398	1.002974917	-0.03563
Empire District Electric Co (The)	2011	-0.0728	85,259	0.99	-0.0737	0.990257198	-0.07451	1.020610968	-0.04415	0.990257198	-0.07451
Fitchburg Gas & Electric Light Co	2007		8,225								
Fitchburg Gas & Electric Light Co	2008	-0.0775	7,752	0.94	-0.0462	0.971143757	-0.01748	0.5	-0.48863	0.971143757	-0.01748
Fitchburg Gas & Electric Light Co	2009	-0.0496	7,752	1.00	-0.0496	1	-0.04956	1	-0.04956	1	-0.04956
Fitchburg Gas & Electric Light Co	2010	-0.0720	7,782	1.00	-0.0718	1.004051864	-0.07170	1	-0.07575	1.004051864	-0.07170
Fitchburg Gas & Electric Light Co	2011	-0.2883	5,516	0.71	-0.2994	0.699327415	-0.30889	0.995207668	-0.01301	0.699327415	-0.30889
Florida Power & Light Co	2007		795,540								
Florida Power & Light Co	2008	-0.0696	796,273	1.00	-0.0710	0.999637795	-0.07229	1.019268015	-0.05266	0.999637795	-0.07229
Florida Power & Light Co	2009	-0.0420	800,771	1.01	-0.0439	1.003962519	-0.04554	1.029279364	-0.02023	1.003962519	-0.04554
Florida Power & Light Co	2010	0.0367	805,527	1.01	0.0367	1.005853515	0.03657	1.007106123	0.03782	1.005853515	0.03657
Florida Power & Light Co	2011	-0.0221	806,416	1.00	-0.0220	1.001186164	-0.02189	0.999970903	-0.02311	1.001186164	-0.02189
Idaho Power Co	2007		708,174								
Idaho Power Co	2008	-0.0933	712,503	1.01	-0.0934	1.006068029	-0.09343	1.011788109	-0.08771	1.006068029	-0.09343
Idaho Power Co	2009	-0.5916	324,055	0.45	-0.5971	0.450346568	-0.60153	1.029563824	-0.02231	0.450346568	-0.60153
Idaho Power Co	2010	-0.0374	325,731	1.01	-0.0424	1.000950474	-0.04665	1.242803593	0.19520	1.000950474	-0.04665
Idaho Power Co	2011	0.0257	326,068	1.00	0.0255	1.000881222	0.02535	1.008024129	0.03249	1.000881222	0.02535
Indiana Michigan Power Co	2007		233,919								
Indiana Michigan Power Co	2008	-0.0710	233,796	1.00	-0.0710	0.999403701	-0.07112	1.000938051	-0.06958	0.999403701	-0.07112
Indiana Michigan Power Co	2009	-0.0964	233,827	1.00	-0.0973	0.999364748	-0.09808	1.016231819	-0.08121	0.999364748	-0.09808
Indiana Michigan Power Co	2010	0.0513	233,752	1.00	0.0515	0.999819163	0.05164	0.996753846	0.04857	0.999819163	0.05164
Indiana Michigan Power Co	2011	-0.0499	233,956	1.00	-0.0509	1.000017269	-0.05173	1.018541135	-0.03321	1.000017269	-0.05173
Indianapolis Power & Light	2007		131,547								
Indianapolis Power & Light	2008	0.0022	126,231	0.96	0.0000	0.957691971	-0.00189	1.004498088	0.04492	0.957691971	-0.00189
Indianapolis Power & Light	2009	0.0614	130,617	1.03	0.0632	1.036284479	0.06470	1	0.02842	1.036284479	0.06470
Indianapolis Power & Light	2010	-0.0021	130,465	1.00	-0.0026	0.998339407	-0.00312	1.010448541	0.00899	0.998339407	-0.00312
Indianapolis Power & Light	2011	0.0102	127,685	0.98	0.0086	0.97729475	0.00723	1.011079105	0.04102	0.97729475	0.00723
Interstate Power & Light Co	2007		227,837								
Interstate Power & Light Co	2008	0.0436	228,543	1.00	0.0436	1.003090567	0.04363	1.003658537	0.04420	1.003090567	0.04363
Interstate Power & Light Co	2009	-0.0199	228,697	1.00	-0.0204	1.000223264	-0.02090	1.063183475	0.04206	1.000223264	-0.02090
Interstate Power & Light Co	2010	-0.1015	229,882	1.01	-0.1041	1.003035714	-0.10623	1.2832	0.17393	1.003035714	-0.10623
Interstate Power & Light Co	2011	0.0075	230,031	1.00	0.0073	1.000445077	0.00707	1.02155326	0.02817	1.000445077	0.00707
Jersey Central Power & Light Co	2007		272,634								
Jersey Central Power & Light Co	2008	-0.0422	275,132	1.01	-0.0450	1.006432269	-0.04771	1.035777385	-0.01837	1.006432269	-0.04771
Jersey Central Power & Light Co	2009	-0.0138	276,230	1.00	-0.0124	1.005373801	-0.01104	0.990877246	-0.02553	1.005373801	-0.01104
Jersey Central Power & Light Co	2010	-0.0118	278,970	1.01	-0.0165	1.005345077	-0.02104	1.05388789	0.02751	1.005345077	-0.02104
Jersey Central Power & Light Co	2011	0.0785	280,157	1.00	0.0796	1.005307798	0.08065	0.994618402	0.06996	1.005307798	0.08065

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Utility Name	Year	Composite TFP	Output 60/40 weight	% Change in Output 60/40	Composite TFP	%Change in Customers	Customer TFP	% Change in Capacity	Capacity TFP	% Change Miles of Line	Miles TFP
Kentucky Power Co	2007		113,818								
Kentucky Power Co	2008	-0.0400	114,273	1.00	-0.0382	1.005517648	-0.03665	0.943350108	-0.09882	1.005517648	-0.03665
Kentucky Power Co	2009	-0.0666	114,575	1.00	-0.0672	1.002183333	-0.06762	1.02210029	-0.04770	1.002183333	-0.06762
Kentucky Power Co	2010	-0.0010	115,000	1.00	-0.0008	1.003893549	-0.00065	0.996271995	-0.00827	1.003893549	-0.00065
Kentucky Power Co	2011	-0.0139	115,378	1.00	-0.0151	1.002310833	-0.01607	1.044155067	0.02577	1.002310833	-0.01607
Kingsport Power Co	2007		14,043								
Kingsport Power Co	2008	0.0489	14,043	1.00	0.0489	1	0.04886	1	0.04886	1	0.04886
Kingsport Power Co	2009	0.1911	14,053	1.00	0.1912	1.000736578	0.19118	1	0.19044	1.000736578	0.19118
Kingsport Power Co	2010	-0.5938	14,041	1.00	-0.5938	0.999183001	-0.59379	1	-0.59298	0.999183001	-0.59379
Kingsport Power Co	2011	0.0984	14,052	1.00	0.0985	1.000817668	0.09850	0.998609179	0.09629	1.000817668	0.09850
Madison Gas & Electric Co	2007		20,538								
Madison Gas & Electric Co	2008	-0.0176	20,565	1.00	-0.0180	1.001009591	-0.01827	1.01369863	-0.00558	1.001009591	-0.01827
Madison Gas & Electric Co	2009	-0.0620	20,570	1.00	-0.0629	0.999495714	-0.06363	1.032094595	-0.03103	0.999495714	-0.06363
Madison Gas & Electric Co	2010	-0.0749	20,905	1.02	-0.0745	1.016649849	-0.07412	1.001636661	-0.08914	1.016649849	-0.07412
Madison Gas & Electric Co	2011	-0.1009	21,026	1.01	-0.1007	1.005955335	-0.10059	1	-0.10654	1.005955335	-0.10059
MDU Resources Group Inc	2007		78,100								
MDU Resources Group Inc	2008	-0.1231	77,990	1.00	-0.1234	0.998314954	-0.12365	1.011541421	-0.11042	0.998314954	-0.12365
MDU Resources Group Inc	2009	-0.0325	79,059	1.01	-0.0325	1.013768304	-0.03241	1.011156187	-0.03502	1.013768304	-0.03241
MDU Resources Group Inc	2010	-0.1124	79,100	1.00	-0.1127	1.000269429	-0.11297	1.012286861	-0.10095	1.000269429	-0.11297
MDU Resources Group Inc	2011	-0.1043	79,195	1.00	-0.1057	1.000023536	-0.10687	1.058211543	-0.04868	1.000023536	-0.10687
Metropolitan Edison Co	2007		205,462								
Metropolitan Edison Co	2008	-0.0540	206,313	1.00	-0.0549	1.003448642	-0.05556	1.039249147	-0.01975	1.003448642	-0.05556
Metropolitan Edison Co	2009	-0.2180	206,928	1.00	-0.2183	1.002706133	-0.21859	1.016227181	-0.20507	1.002706133	-0.21859
Metropolitan Edison Co	2010	0.0490	207,490	1.00	0.0490	1.00269883	0.04899	1.003516776	0.04980	1.00269883	0.04899
Metropolitan Edison Co	2011	-0.1913	208,086	1.00	-0.1915	1.002691566	-0.19168	1.011744649	-0.18263	1.002691566	-0.19168
Monongahela Power Co	2007		240,924								
Monongahela Power Co	2008	0.0194	241,789	1.00	0.0216	1.005459113	0.02348	0.925891846	-0.05608	1.005459113	0.02348
Monongahela Power Co	2009	0.0286	260,447	1.08	0.0295	1.077900113	0.03021	1.043880437	-0.00381	1.077900113	0.03021
Monongahela Power Co	2010	-0.2155	242,479	0.93	-0.2195	0.927678094	-0.22286	1.086634932	-0.06390	0.927678094	-0.22286
Monongahela Power Co	2011	-0.0018	234,380	0.97	-0.0097	0.959952354	-0.01631	1.231567597	0.25531	0.959952354	-0.01631
Northern States Power Co (Minnesota)	2007		1,022,779								
Northern States Power Co (Minnesota)	2008	-0.0478	1,032,121	1.01	-0.0477	1.009190402	-0.04765	1.005819231	-0.05103	1.009190402	-0.04765
Northern States Power Co (Minnesota)	2009	-0.0188	1,045,187	1.01	-0.0191	1.012479518	-0.01924	1.023257967	-0.00846	1.012479518	-0.01924
Northern States Power Co (Minnesota)	2010	-0.0299	1,046,880	1.00	-0.0304	1.001263413	-0.03071	1.02229962	-0.00967	1.001263413	-0.03071
Northern States Power Co (Minnesota)	2011	-0.0705	1,049,681	1.00	-0.0709	1.002304521	-0.07130	1.023804256	-0.04980	1.002304521	-0.07130
Northern States Power Co (Wisconsin)	2007		369,284								
Northern States Power Co (Wisconsin)	2008	-0.1038	367,693	1.00	-0.1039	0.995656132	-0.10392	1	-0.09957	0.995656132	-0.10392
Northern States Power Co (Wisconsin)	2009	-0.0135	371,326	1.01	-0.0134	1.009920552	-0.01337	1.005161956	-0.01813	1.009920552	-0.01337
Northern States Power Co (Wisconsin)	2010	-0.0770	370,328	1.00	-0.0774	0.996973274	-0.07775	1.03736038	-0.03736	0.996973274	-0.07775
Northern States Power Co (Wisconsin)	2011	-0.1080	372,062	1.00	-0.1083	1.004448167	-0.10849	1.031188119	-0.08175	1.004448167	-0.10849
NorthWestern Corp	2007		319,136								
NorthWestern Corp	2008	0.0072	322,020	1.01	0.0037	1.006194087	0.00088	1.219764706	0.21445	1.006194087	0.00088
NorthWestern Corp	2009	0.0054	326,386	1.01	0.0055	1.013673508	0.00564	1.006481481	-0.00155	1.013673508	0.00564
NorthWestern Corp	2010	-0.1686	284,010	0.87	-0.1718	0.86752987	-0.17442	1.032428703	-0.00952	0.86752987	-0.17442
NorthWestern Corp	2011	-0.0548	285,337	1.00	-0.0561	1.003606846	-0.05713	1.059775748	-0.00096	1.003606846	-0.05713

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NSTAR Electric Co	2007		364,093								
NSTAR Electric Co	2008	-0.0448	369,378	1.01	-0.0448	1.014519449	-0.04478	1.014410732	-0.04489	1.014519449	-0.04478
NSTAR Electric Co	2009	-0.0413	370,761	1.00	-0.0433	1.002008613	-0.04501	1.043392912	-0.00362	1.002008613	-0.04501
NSTAR Electric Co	2010	0.0480	381,362	1.03	0.0487	1.029171645	0.04924	1.015892663	0.03596	1.029171645	0.04924
NSTAR Electric Co	2011	-0.0979	349,958	0.92	-0.1021	0.913910708	-0.10584	1.0008285	-0.01892	0.913910708	-0.10584
Ohio Edison Co	2007		638,089								
Ohio Edison Co	2008	-0.0889	638,832	1.00	-0.0887	1.001309554	-0.08856	0.976105137	-0.11376	1.001309554	-0.08856
Ohio Edison Co	2009	-0.0330	639,111	1.00	-0.0319	1.001307841	-0.03105	0.846556137	-0.18580	1.001307841	-0.03105
Ohio Edison Co	2010	-0.1562	640,076	1.00	-0.1565	1.001306133	-0.15669	1.044164038	-0.11383	1.001306133	-0.15669
Ohio Edison Co	2011	0.0530	640,885	1.00	0.0531	1.00130443	0.05313	0.993328298	0.04516	1.00130443	0.05313
Ohio Power Co	2007		481,912								
Ohio Power Co	2008	-0.0288	482,042	1.00	-0.0280	1.000889714	-0.02741	0.978677784	-0.04963	1.000889714	-0.02741
Ohio Power Co	2009	-0.0932	482,590	1.00	-0.0937	1.000721467	-0.09410	1.015944499	-0.07888	1.000721467	-0.09410
Ohio Power Co	2010	-0.0069	484,271	1.00	-0.0076	1.002944243	-0.00810	1.02243321	0.01139	1.002944243	-0.00810
Ohio Power Co	2011	-0.0251	483,635	1.00	-0.0245	0.999195918	-0.02401	0.981112869	-0.04209	0.999195918	-0.02401
Oklahoma Gas & Electric Co	2007		442,485								
Oklahoma Gas & Electric Co	2008	-0.0672	448,184	1.01	-0.0669	1.013106108	-0.06668	1.00180538	-0.07798	1.013106108	-0.06668
Oklahoma Gas & Electric Co	2009	-0.0906	460,168	1.03	-0.0905	1.026761494	-0.09051	1.025680303	-0.09159	1.026761494	-0.09051
Oklahoma Gas & Electric Co	2010	-0.1052	464,167	1.01	-0.1067	1.007466907	-0.10789	1.069182114	-0.04617	1.007466907	-0.10789
Oklahoma Gas & Electric Co	2011	-0.0232	493,851	1.06	-0.0216	1.065305074	-0.02022	1.000821659	-0.08470	1.065305074	-0.02022
Oncor Electric Delivery	2007		1,216,978								
Oncor Electric Delivery	2008	-0.0694	1,224,604	1.01	-0.0695	1.006139806	-0.06963	1.010834315	-0.06494	1.006139806	-0.06963
Oncor Electric Delivery	2009	0.0051	1,228,694	1.00	0.0039	1.002294947	0.00288	1.040721916	0.04130	1.002294947	0.00288
Oncor Electric Delivery	2010	-0.0825	1,235,175	1.01	-0.0836	1.004353766	-0.08447	1.037027202	-0.05180	1.004353766	-0.08447
Oncor Electric Delivery	2011	-0.0562	1,240,544	1.00	-0.0572	1.0034681	-0.05812	1.033656576	-0.02793	1.0034681	-0.05812
Orange & Rockland Utilities Inc	2007		60,807								
Orange & Rockland Utilities Inc	2008	0.0227	61,703	1.01	0.0252	1.01693406	0.02742	0.9687545	-0.02076	1.01693406	0.02742
Orange & Rockland Utilities Inc	2009	-0.0113	63,232	1.02	-0.0100	1.025924972	-0.00888	1	-0.03480	1.025924972	-0.00888
Orange & Rockland Utilities Inc	2010	-0.0147	63,661	1.01	-0.0146	1.006861351	-0.01449	1.004904875	-0.01645	1.006861351	-0.01449
Orange & Rockland Utilities Inc	2011	-0.1770	64,242	1.01	-0.1773	1.008835702	-0.17763	1.015530247	-0.17093	1.008835702	-0.17763
Pacific Gas & Electric Co	2007		1,645,243								
Pacific Gas & Electric Co	2008	-0.0131	1,651,281	1.00	-0.0137	1.003134056	-0.01427	1.030328445	0.01293	1.003134056	-0.01427
Pacific Gas & Electric Co	2009	-0.1078	1,653,620	1.00	-0.1084	1.000899893	-0.10892	1.026407144	-0.08341	1.000899893	-0.10892
Pacific Gas & Electric Co	2010	-0.1170	1,654,810	1.00	-0.1171	1.000623165	-0.11718	1.005283169	-0.11252	1.000623165	-0.11718
Pacific Gas & Electric Co	2011	-0.0577	1,652,749	1.00	-0.0585	0.998057261	-0.05920	1.031520819	-0.02574	0.998057261	-0.05920
PECO Energy Co	2007		309,828								
PECO Energy Co	2008	0.0010	314,540	1.02	0.0007	1.015017185	0.00055	1.019985121	0.00552	1.015017185	0.00055
PECO Energy Co	2009	-0.0585	315,916	1.00	-0.0584	1.004387923	-0.05843	1.004011537	-0.05881	1.004387923	-0.05843
PECO Energy Co	2010	-0.0339	316,776	1.00	-0.0350	1.001734162	-0.03598	1.027506274	-0.01021	1.001734162	-0.03598
PECO Energy Co	2011	-0.0914	248,144	0.78	-0.1096	0.767389748	-0.12557	1.173377896	0.28042	0.767389748	-0.12557
Pennsylvania Electric Co	2007		303,248								
Pennsylvania Electric Co	2008	-0.0784	304,387	1.00	-0.0782	1.003886156	-0.07807	0.996348144	-0.08561	1.003886156	-0.07807
Pennsylvania Electric Co	2009	-0.0202	305,470	1.00	-0.0203	1.003454536	-0.02045	1.00946854	-0.01444	1.003454536	-0.02045
Pennsylvania Electric Co	2010	0.1006	306,484	1.00	0.1007	1.003442643	0.10083	0.996293495	0.09368	1.003442643	0.10083
Pennsylvania Electric Co	2011	-0.3440	307,600	1.00	-0.3442	1.003430832	-0.34443	1.015716347	-0.33215	1.003430832	-0.34443

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Utility Name	Year	Composite TFP	Output 60/40 weight	% Change in Output 60/40	Composite TFP	%Change in Customers	Customer TFP	% Change in Capacity	Capacity TFP	% Change Miles of Line	Miles TFP
Pennsylvania Power Co	2007		135,918								
Pennsylvania Power Co	2008	-0.1511	136,326	1.00	-0.1520	1.00224775	-0.15275	1.148361127	-0.00663	1.00224775	-0.15275
Pennsylvania Power Co	2009	-0.0950	136,592	1.00	-0.0947	1.002242709	-0.09440	0.952428643	-0.14421	1.002242709	-0.09440
Pennsylvania Power Co	2010	-0.0615	136,914	1.00	-0.0616	1.00223769	-0.06177	1.024185068	-0.03982	1.00223769	-0.06177
Pennsylvania Power Co	2011	0.0214	137,218	1.00	0.0214	1.002232694	0.02140	1	0.01917	1.002232694	0.02140
Potomac Edison Co (The)	2007		241,688								
Potomac Edison Co (The)	2008	-0.0202	245,434	1.02	-0.0174	1.0178601	-0.01502	0.914005093	-0.11888	1.0178601	-0.01502
Potomac Edison Co (The)	2009	-0.0620	260,070	1.06	-0.0635	1.058396892	-0.06473	1.118761442	-0.00437	1.058396892	-0.06473
Potomac Edison Co (The)	2010	-0.1012	189,147	0.73	-0.1028	0.72597289	-0.10413	0.787122021	-0.04298	0.72597289	-0.10413
Potomac Edison Co (The)	2011	0.0437	210,630	1.11	0.0411	1.111351648	0.03884	1.206453946	0.13395	1.111351648	0.03884
PPL Electric Utilities Corp	2007		427,778								
PPL Electric Utilities Corp	2008	0.0009	430,414	1.01	0.0003	1.005646757	-0.00020	1.015471192	0.00962	1.005646757	-0.00020
PPL Electric Utilities Corp	2009	-0.0124	432,019	1.00	-0.0131	1.00311047	-0.01367	1.014848437	-0.00194	1.00311047	-0.01367
PPL Electric Utilities Corp	2010	0.1396	433,782	1.00	0.1385	1.003131794	0.13756	1.020906648	0.15533	1.003131794	0.13756
PPL Electric Utilities Corp	2011	-0.0170	475,992	1.10	-0.0121	1.101699537	-0.00773	1.020801141	-0.08862	1.101699537	-0.00773
Progress Energy Carolinas	2007		756,722								
Progress Energy Carolinas	2008	-0.0153	757,096	1.00	-0.0157	1.000197579	-0.01597	1.005996909	-0.01017	1.000197579	-0.01597
Progress Energy Carolinas	2009	0.0292	779,970	1.03	0.0294	1.030360988	0.02954	1.027470501	0.02664	1.030360988	0.02954
Progress Energy Carolinas	2010	-0.0424	773,377	0.99	-0.0330	1.000017529	-0.02449	0.835376916	-0.18913	1.000017529	-0.02449
Progress Energy Carolinas	2011	-0.0216	774,958	1.00	-0.0217	1.001897709	-0.02188	1.005274463	-0.01850	1.001897709	-0.02188
Progress Energy Florida	2007		378,187								
Progress Energy Florida	2008	-0.0030	379,466	1.00	-0.0056	1.001073719	-0.00792	1.060795097	0.05180	1.001073719	-0.00792
Progress Energy Florida	2009	-0.2429	380,192	1.00	-0.2444	1.000578736	-0.24578	1.033194914	-0.21316	1.000578736	-0.24578
Progress Energy Florida	2010	0.0179	381,864	1.00	0.0154	1.002188965	0.01315	1.054645764	0.06561	1.002188965	0.01315
Progress Energy Florida	2011	0.0542	382,990	1.00	0.0532	1.002096183	0.05237	1.021326958	0.07160	1.002096183	0.05237
Public Service Co of Colorado	2007		913,422								
Public Service Co of Colorado	2008	-0.0554	919,538	1.01	-0.0556	1.006516035	-0.05580	1.026356514	-0.03596	1.006516035	-0.05580
Public Service Co of Colorado	2009	-0.0221	925,509	1.01	-0.0239	1.005079083	-0.02529	1.158271686	0.12790	1.005079083	-0.02529
Public Service Co of Colorado	2010	-0.0970	932,810	1.01	-0.0975	1.00746627	-0.09794	1.04722968	-0.05818	1.00746627	-0.09794
Public Service Co of Colorado	2011	-0.0695	945,272	1.01	-0.0703	1.012659515	-0.07105	1.076098357	-0.00761	1.012659515	-0.07105
Public Service Co of New Mexico	2007		150,585								
Public Service Co of New Mexico	2008	-0.1096	152,378	1.01	-0.1094	1.012051083	-0.10928	1.00744559	-0.11388	1.012051083	-0.10928
Public Service Co of New Mexico	2009	-0.0357	152,935	1.00	-0.0355	1.003785966	-0.03540	0.999918785	-0.03927	1.003785966	-0.03540
Public Service Co of New Mexico	2010	-0.1248	152,167	0.99	-0.1252	0.994592319	-0.12558	1.006416504	-0.11375	0.994592319	-0.12558
Public Service Co of New Mexico	2011	-0.0525	152,625	1.00	-0.0534	1.002202363	-0.05423	1.027116455	-0.02932	1.002202363	-0.05423
Public Service Co of Oklahoma	2007		220,808								
Public Service Co of Oklahoma	2008	-0.6926	221,404	1.00	-0.6945	1.001027791	-0.69620	1.059495116	-0.63773	1.001027791	-0.69620
Public Service Co of Oklahoma	2009	0.0372	223,246	1.01	0.0369	1.008096396	0.03668	1.015445402	0.04403	1.008096396	0.03668
Public Service Co of Oklahoma	2010	-0.0502	220,618	0.99	-0.0495	0.988798955	-0.04896	0.970109657	-0.06765	0.988798955	-0.04896
Public Service Co of Oklahoma	2011	-0.1033	220,448	1.00	-0.1048	0.997960774	-0.10606	1.040413248	-0.06361	0.997960774	-0.10606
Public Service Electric & Gas Co	2007		233,441								
Public Service Electric & Gas Co	2008	0.0351	247,874	1.06	0.0379	1.064347291	0.04043	1.018884836	-0.00503	1.064347291	0.04043
Public Service Electric & Gas Co	2009	-0.0455	248,877	1.00	-0.0456	1.00399671	-0.04564	1.004944638	-0.04469	1.00399671	-0.04564
Public Service Electric & Gas Co	2010	-0.1335	252,246	1.01	-0.1338	1.013284384	-0.13407	1.017960638	-0.12939	1.013284384	-0.13407
Public Service Electric & Gas Co	2011	-0.1516	252,282	1.00	-0.1524	0.999464049	-0.15306	1.012157874	-0.14036	0.999464049	-0.15306

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Utility Name	**Year**	**Composite TFP**	**Output 60/40 weight**	**% Change in Output 60/40**	**Composite TFP**	**%Change in Customers**	**Customer TFP**	**% Change in Capacity**	**Capacity TFP**	**% Change Miles of Line**	**Miles TFP**
San Diego Gas & Electric Co	2007		249,786								
San Diego Gas & Electric Co	2008	-0.0717	251,609	1.01	-0.0725	1.006638023	-0.07317	1.029885961	-0.04992	1.006638023	-0.07317
San Diego Gas & Electric Co	2009	-0.0717	252,825	1.00	-0.0722	1.004425891	-0.07256	1.018327606	-0.05866	1.004425891	-0.07256
San Diego Gas & Electric Co	2010	-0.0734	253,333	1.00	-0.0725	1.002800499	-0.07172	0.976003	-0.09852	1.002800499	-0.07172
San Diego Gas & Electric Co	2011	-0.0959	254,364	1.00	-0.0959	1.004075367	-0.09593	1.003896603	-0.09611	1.004075367	-0.09593
South Carolina Electric & Gas Co	2007		287,949								
South Carolina Electric & Gas Co	2008	-0.0698	292,729	1.02	-0.0691	1.017207672	-0.06849	0.999760479	-0.08594	1.017207672	-0.06849
South Carolina Electric & Gas Co	2009	-0.0762	295,443	1.01	-0.0762	1.0092614	-0.07623	1.009583134	-0.07591	1.0092614	-0.07623
South Carolina Electric & Gas Co	2010	-0.0398	297,636	1.01	-0.0408	1.006477781	-0.04179	1.034013605	-0.01425	1.006477781	-0.04179
South Carolina Electric & Gas Co	2011	-0.0566	299,549	1.01	-0.0576	1.005552684	-0.05845	1.030446756	-0.03355	1.005552684	-0.05845
Southern California Edison Co	2007		1,288,333								
Southern California Edison Co	2008	0.2210	1,288,982	1.00	0.2202	0.999833663	0.21953	1.02507925	0.24478	0.999833663	0.21953
Southern California Edison Co	2009	-0.5144	1,311,765	1.02	-0.5161	1.016271393	-0.51749	1.067896797	-0.46587	1.016271393	-0.51749
Southern California Edison Co	2010	-0.1366	1,212,574	0.92	-0.1412	0.920494057	-0.14505	1.056805189	-0.00874	0.920494057	-0.14505
Southern California Edison Co	2011	0.0097	1,209,247	1.00	0.0080	0.995761463	0.00652	1.041577771	0.05233	0.995761463	0.00652
Southern Indiana Gas & Electric Co	2007		74,488								
Southern Indiana Gas & Electric Co	2008	-0.0551	75,063	1.01	-0.0468	1.01503738	-0.03950	0.854296829	-0.20024	1.01503738	-0.03950
Southern Indiana Gas & Electric Co	2009	-0.1413	75,229	1.00	-0.1426	1.001090878	-0.14370	1.030081413	-0.11471	1.001090878	-0.14370
Southern Indiana Gas & Electric Co	2010	-0.1567	76,434	1.02	-0.1582	1.014698891	-0.15956	1.048091092	-0.12617	1.014698891	-0.15956
Southern Indiana Gas & Electric Co	2011	-0.0196	76,737	1.00	-0.0194	1.004103504	-0.01931	1.000639059	-0.02277	1.004103504	-0.01931
Southwestern Electric Power Co	2007		224,957								
Southwestern Electric Power Co	2008	-0.0863	226,682	1.01	-0.0875	1.006619604	-0.08858	1.033865371	-0.06133	1.006619604	-0.08858
Southwestern Electric Power Co	2009	-0.0416	226,981	1.00	-0.0428	1.000260102	-0.04391	1.027117734	-0.01705	1.000260102	-0.04391
Southwestern Electric Power Co	2010	-0.0999	229,782	1.01	-0.1001	1.012165804	-0.10031	1.016468435	-0.09601	1.012165804	-0.10031
Southwestern Electric Power Co	2011	-0.0624	231,022	1.01	-0.0620	1.005694741	-0.06175	0.998328404	-0.06912	1.005694741	-0.06175
Southwestern Public Service Co	2007		494,407								
Southwestern Public Service Co	2008	0.0015	515,982	1.04	0.0018	1.043873083	0.00201	1.025961956	-0.01590	1.043873083	0.00201
Southwestern Public Service Co	2009	-0.1460	520,408	1.01	-0.1470	1.007786267	-0.14779	1.069452832	-0.08612	1.007786267	-0.14779
Southwestern Public Service Co	2010	-0.0256	502,175	0.96	-0.0275	0.963367838	-0.02909	1.08069799	0.08824	0.963367838	-0.02909
Southwestern Public Service Co	2011	-0.1032	507,409	1.01	-0.1057	1.00831164	-0.10783	1.146731463	0.03059	1.00831164	-0.10783
Tampa Electric Co	2007		161,119								
Tampa Electric Co	2008	-0.1869	129,273	0.80	-0.1950	0.795352446	-0.20194	0.992711983	-0.00458	0.795352446	-0.20194
Tampa Electric Co	2009	-0.1255	129,432	1.00	-0.1269	1.000042623	-0.12804	1.02717775	-0.10091	1.000042623	-0.12804
Tampa Electric Co	2010	-0.0213	130,686	1.01	-0.0212	1.009760152	-0.02116	1.008178132	-0.02274	1.009760152	-0.02116
Tampa Electric Co	2011	-0.0328	130,763	1.00	-0.0329	1.000508129	-0.03302	1.002317655	-0.03121	1.000508129	-0.03302
Toledo Edison Co (The)	2007	0.0000	181,418		0.0000		0.00000		0.00000		0.00000
Toledo Edison Co (The)	2008	-0.0490	181,631	1.00	-0.0504	1.000056141	-0.05148	1.213714767	0.16218	1.000056141	-0.05148
Toledo Edison Co (The)	2009	-0.0195	181,461	1.00	-0.0183	1.000056138	-0.01730	0.843327556	-0.17403	1.000056138	-0.01730
Toledo Edison Co (The)	2010	-0.0568	181,524	1.00	-0.0572	1.000056135	-0.05748	1.054254007	-0.00328	1.000056135	-0.05748
Toledo Edison Co (The)	2011	0.0242	181,552	1.00	0.0241	1.000056131	0.02399	1.018323587	0.04226	1.000056131	0.02399
Tucson Electric Power Co	2007		99,745								
Tucson Electric Power Co	2008	0.0274	101,230	1.01	0.0266	1.01421721	0.02597	1.026525199	0.03828	1.01421721	0.02597
Tucson Electric Power Co	2009	-0.1793	100,890	1.00	-0.1795	0.996449713	-0.17971	1	-0.17616	0.996449713	-0.17971
Tucson Electric Power Co	2010	-0.0714	101,703	1.01	-0.0761	1.003803158	-0.08032	1.080749354	-0.00338	1.003803158	-0.08032
Tucson Electric Power Co	2011	-0.2288	101,957	1.00	-0.2265	1.004659166	-0.22430	0.968253968	-0.26071	1.004659166	-0.22430

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Utility Name	Year	Composite TFP	Output 60/40 weight	% Change in Output 60/40	Composite TFP	%Change in Customers	Customer TFP	% Change in Capacity	Capacity TFP	% Change Miles of Line	Miles TFP
Unitil Energy Systems	2007		20,433								
Unitil Energy Systems	2008	-0.0131	20,626	1.01	-0.0131	1.009466866	-0.01305	1	-0.02251	1.009466866	-0.01305
Unitil Energy Systems	2009	-0.0637	20,699	1.00	-0.0638	1.003455084	-0.06394	1.024193548	-0.04320	1.003455084	-0.06394
Unitil Energy Systems	2010	-0.1099	20,233	0.98	-0.1100	0.97737334	-0.11008	0.996062992	-0.09139	0.97737334	-0.11008
Unitil Energy Systems	2011	-0.2897	15,852	0.78	-0.2915	0.782083543	-0.29289	1.063241107	-0.01173	0.782083543	-0.29289
UNS Electric Inc	2007		39,151								
UNS Electric Inc	2008	-0.0656	39,677	1.01	-0.0659	1.013177474	-0.06609	1.032635983	-0.04663	1.013177474	-0.06609
UNS Electric Inc	2009	-0.1011	40,064	1.01	-0.1025	1.008649177	-0.10363	1.098865478	-0.01341	1.008649177	-0.10363
UNS Electric Inc	2010	-0.0599	40,330	1.01	-0.0600	1.006511368	-0.06012	1.014749263	-0.05188	1.006511368	-0.06012
UNS Electric Inc	2011	-0.1788	40,573	1.01	-0.1801	1.004933436	-0.18123	1.085755814	-0.10041	1.004933436	-0.18123
Virginia Electric & Power Co	2007		645,820								
Virginia Electric & Power Co	2008	-0.0785	656,366	1.02	-0.0783	1.016477512	-0.07818	1.012951054	-0.08170	1.016477512	-0.07818
Virginia Electric & Power Co	2009	0.0532	657,559	1.00	0.0513	1.000161519	0.04963	1.040075831	0.08954	1.000161519	0.04963
Virginia Electric & Power Co	2010	-0.2052	667,053	1.01	-0.2058	1.01385607	-0.20640	1.027383324	-0.19287	1.01385607	-0.20640
Virginia Electric & Power Co	2011	-0.1720	669,832	1.00	-0.1733	1.00299309	-0.17451	1.029885437	-0.14761	1.00299309	-0.17451
West Penn Power Co	2007		281,029								
West Penn Power Co	2008	-0.1171	279,698	1.00	-0.1177	0.994797732	-0.11815	1.016219751	-0.09673	0.994797732	-0.11815
West Penn Power Co	2009	-0.0322	298,390	1.07	-0.0244	1.073387851	-0.01780	0.778221135	-0.31296	1.073387851	-0.01780
West Penn Power Co	2010	-0.0439	282,576	0.95	-0.0474	0.944175373	-0.05018	1.118590804	0.12424	0.944175373	-0.05018
West Penn Power Co	2011	-0.2784	225,649	0.80	-0.2838	0.793980698	-0.28837	1.032160284	-0.05019	0.793980698	-0.28837
Westar Energy Inc	2007		319,917								
Westar Energy Inc	2008	-0.0765	323,966	1.01	-0.0775	1.011831554	-0.07835	1.065584469	-0.02459	1.011831554	-0.07835
Westar Energy Inc	2009	-0.1192	325,800	1.01	-0.1195	1.005444348	-0.11969	1.018908367	-0.10623	1.005444348	-0.11969
Westar Energy Inc	2010	-0.1927	327,098	1.00	-0.1923	1.004318173	-0.19199	0.9837716	-0.21253	1.004318173	-0.19199
Westar Energy Inc	2011	-0.0300	330,990	1.01	-0.0428	1.001266997	-0.05344	1.665342905	0.61064	1.001266997	-0.05344
Wheeling Power Co	2007		17,621								
Wheeling Power Co	2008	-0.0754	17,624	1.00	-0.0742	1.001185871	-0.07317	0.952590959	-0.12177	1.001185871	-0.07317
Wheeling Power Co	2009	-0.1139	17,623	1.00	-0.1139	0.999941363	-0.11391	1	-0.11385	0.999941363	-0.11391
Wheeling Power Co	2010	0.0456	17,679	1.00	0.0434	1.001337	0.04157	1.096064815	0.13629	1.001337	0.04157
Wheeling Power Co	2011	-0.2700	17,874	1.01	-0.2698	1.011126793	-0.26975	1.006335797	-0.27454	1.011126793	-0.26975
Wisconsin Electric Power Co	2007		478,339								
Wisconsin Electric Power Co	2008	0.2785	487,946	1.02	0.2794	1.020903574	0.28018	1.006670147	0.26594	1.020903574	0.28018
Wisconsin Electric Power Co	2009	-0.2221	491,365	1.01	-0.2227	1.006494936	-0.22319	1.015498963	-0.21419	1.006494936	-0.22319
Wisconsin Electric Power Co	2010	-0.0213	490,415	1.00	-0.0281	0.991862627	-0.03432	1.099985816	0.07380	0.991862627	-0.03432
Wisconsin Electric Power Co	2011	-0.0925	489,827	1.00	-0.0896	1.001521734	-0.08687	0.958477866	-0.12991	1.001521734	-0.08687
Wisconsin Power & Light Co	2007		213,754								
Wisconsin Power & Light Co	2008	-0.0578	215,407	1.01	-0.0582	1.007408824	-0.05850	1.045769145	-0.02014	1.007408824	-0.05850
Wisconsin Power & Light Co	2009	-0.1086	215,721	1.00	-0.1090	1.001138736	-0.10931	1.038215201	-0.07223	1.001138736	-0.10931
Wisconsin Power & Light Co	2010	-0.1291	217,466	1.01	-0.1295	1.007725118	-0.12986	1.047912811	-0.08967	1.007725118	-0.12986
Wisconsin Power & Light Co	2011	-0.0736	218,189	1.00	-0.0740	1.003009923	-0.07431	1.036695447	-0.04063	1.003009923	-0.07431
Wisconsin Public Service Corp	2007		221,179								
Wisconsin Public Service Corp	2008	-0.0711	221,302	1.00	-0.0715	1.000186081	-0.07187	1.02430105	-0.04776	1.000186081	-0.07187
Wisconsin Public Service Corp	2009	-0.0119	221,374	1.00	-0.0123	1	-0.01260	1.020730162	0.00813	1	-0.01260
Wisconsin Public Service Corp	2010	-0.0226	221,377	1.00	-0.0226	1	-0.02260	1.000902629	-0.02170	1	-0.02260
Wisconsin Public Service Corp	2011	0.0100	223,385	1.01	0.0103	1.009302326	0.01054	0.994814564	-0.00395	1.009302326	0.01054

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

FORMULA EXCEL MODELS

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Appendix D5

EFFICIENCY CARRY-OVER MECHANISM

EFFICIENCY CARRY-OVER MECHANISM

In this appendix FBC 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. FBC's proposed ECM provides the same level of incentive to pursue efficiencies in the fifth year as it does in the first year, meaning that rates coming out of the PBR should embed achievable efficiencies.

The ECM provides the incentive for FBC 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 FBC, 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. Capital expenditure savings multiplied by a rate base benefit factor of 12 percent. (The rate base benefit factor of 12 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 12 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 FBC 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 FBC would recover the amounts calculated from customers (assuming the value is positive) through the 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 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 ($ Thousands)										
4	Allowed O&M per PBR formula (net of OH Capitalized)		$ 49,073	$ 49,366	$ 48,746	$ 49,879	$ 50,620				
5	Actual O&M		$ 48,500	$ 48,200	$ 47,200	$ 48,500	$ 49,000				
6	O&M Savings Achieved		$ 573	$ 1,166	$ 1,546	$ 1,379	$ 1,620				
7	**Incremental O&M Savings over prior year cumulative savings**		**$ 573**	**$ 593**	**$ 380**	**$ (167)**	**$ 241**				
8											
9	**b).** Capital Expenditures Benefits achieved ($ Thousands)										
10	Capital Expenditures allowed per PBR formula		$ 72,728	$ 69,087	$ 52,397	$ 53,632	$ 54,624				
11	Actual Capital Expenditures		$ 70,000	$ 70,500	$ 50,000	$ 52,000	$ 52,500				
12	Capital Expenditure Savings		$ 2,728	$ (1,413)	$ 2,397	$ 1,632	$ 2,124				
13	x Rate Base Benefit Factor		12%	12%	12%	12%	12%				
14	**Plant Additions Benefit**		**$ 327**	**$ (170)**	**$ 288**	**$ 196**	**$ 255**				
15											
16	**c).** Total Annual Revenue Requirement Benefits (Σ Lines 7+14)		$ 900	$ 423	$ 668	$ 29	$ 496				
17	**x 50% Earnings Sharing**	50.00%	**$ 450**	**$ 212**	**$ 334**	**$ 15**	**$ 248**				
18											
19											
20	Incremental Benefits Sharing for Phase-out ($ Thousands)										
21	1st Year - 2014		$ 450	$ 450	$ 450	$ 450	$ 450				
22	2nd Year - 2015			$ 212	$ 212	$ 212	$ 212	$ 212			
23	3rd Year - 2016				$ 334	$ 334	$ 334	$ 334	$ 334		
24	4th Year - 2017					$ 15	$ 15	$ 15	$ 15	$ 15	
25	5th Year - 2018						$ 248	$ 248	$ 248	$ 248	$ 248
26	Total Incremental Benefits Sharing		$ 450	$ 662	$ 996	$ 1,010	$ 1,258	$ 808	$ 596	$ 262	$ 248
27											
28	Rate adjustment permitted? (Y/N)		N	N	N	N	N	**Y**	**Y**	**Y**	**Y**
29											
30											
31	Revenue Impact of End-of-Plan Benefits Phase-Out ($ Thousands)							**$ 808**	**$ 596**	**$ 262**	**$ 248**

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. FBC is proposing a 12 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. FBC pays property taxes on certain types of assets (e.g. land and buildings) based on assessed values and mill rates. FBC 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.

FBC has calculated the rate base carrying cost (excluding property taxes) of several asset types to provide support for the proposed 12 percent factor to be used as a Rate Base Benefit Factor. The asset types analyzed are (1) water wheels, turbines and generators for a low depreciation rate – low capital cost allowance (CCA) rate asset; (2) station equipment (transmission plant) for a medium depreciation rate – low CCA rate asset; (3) computer equipment for a medium/high depreciation rate – high CCA rate asset; and (4) transportation equipment 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 (Water Wheels, Turbines & Generators)	Depreciation - 1.95%, CCA - 8%	8.9%
Medium Depreciation - Low CCA (Station Equipment (Transmission Plant))	Depreciation - 3.44%, CCA - 8%	10.6%
Medium / High Depreciation - High CCA (Computer Equipment)	Depreciation - 7.61%, CCA - 55%	10.4%
High Depreciation - High CCA (Transportation Equipment)	Depreciation - 10.71%, CCA - 30%	15.2%

FBC believes the proposed 12 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 D6

SERVICE QUALITY INDICATOR REPORT

Service Quality Indicators

July 2013

Table of Contents

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 its previous PBR Plans, FBC 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 is maintained at acceptable levels throughout the term of PBR Period.

In developing the proposed SQIs discussed in this report, FBC reviewed its experience with the non-financial performance measures that were a component of its 2007-2011 PBR Plan and 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 FBC, as well as proposed updates and modifications are discussed. These 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 propose suite of SQIs for the current application, the following criteria were considered:

Table D6-1: 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. 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 FBC*

The inclusion of SQIs has continued to evolve throughout the Company's previous PBR Plans. In the 1996 PBR Settlement, nine service quality indicators (then referred to as Performance Standards) were agreed to. In 1999, three new indicators were added and one discontinued. In 2000 a second measure was discontinued. The 2006 PBR Settlement retained the majority of the indicators (six) from the previous PBR Plan, changed the status of one SQI to an informational indicator, discontinued three, and added seven new SQIs to assess the Company's performance.

For the 2014 – 2018 PBR term, FBC is proposing further refinements to its SQIs to better reflect the range of its customer interests. The proposed suite of SQIs includes:

- Retention of seven existing SQIs – Normalized System Average Interruption Duration Index, System Average Interruption Frequency Index, Customer Satisfaction Index, Meters Read as Scheduled, Telephone Service Factor, and Emergency Response Time;
- Redefinition of one existing SQI measuring billing accuracy;
- Addition of one new SQI - First Contact Resolution;
- Discontinuation of six existing SQIs - Generation Forced Outage Rate, Residential Connections Completion Time, Residential Extensions Time to Quote, Residential Extensions Completion Time, Injury Frequency Rate, and Vehicle Incident Rate.

Table D6-2 following outlines the history and evolution of FBC's SQIs over the three PBR periods (1996-2004, 2007-2011, and the proposed 2014 PBR). A detailed discussion of the proposed SQIs is presented in the following sections of this report.

Table D6-2: History and Evolution of SQIs at FBC (1996 - 2014)

	Service Quality Indicator	1996 PBR	2007 PBR	Proposed 2014 PBR
1	System Average Interruption Frequency Index	Included	Definition changed to Normalized	Included
2	System Average Interruption Duration Index	Included	Definition changed to Normalized	Included
3	Customer Average Interruption Duration Index	Included	Discontinued	-
4	Index of Reliability	Included	Discontinued	-
5	Generator Forced Outages	Added (1999-2004)	Included	Discontinued
6	Generation Incapability Factor	Added (1999-2004)	Discontinued	-
7	Generator Operating Factor	Added (1999 only)	-	-
8	System Losses	Included (1996-1998)	-	-
9	Customer Satisfaction Index	Included	Included (Redesigned)	Included
10	Billing Accuracy	-	Included	Replaced with Billing Index
11	First Contact Resolution	-	-	Included
12	Meters Read as Scheduled	-	Included	Included
13	Telephone Service Factor	-	Included	Included
14	Emergency Response Time	-	Included	Included
15	Residential Connections Completion Time	-	Included	Discontinued
16	Residential Extensions Quoting Time	-	Included	Discontinued
17	Residential Extensions Completion Time	-	Included	Discontinued
18	Injury Frequency Rate	Included (Disabling Injury Frequency Rate)	Definition changed to All Injury Frequency Rate	Included
19	Injury Severity Rate	Included	Included	Discontinued
20	Vehicle Incident Rate	Included	Included	Discontinued

3. PROPOSED SERVICE QUALITY INDICATORS AND BENCHMARKS

3.1 *OPERATIONAL SQIS*

3.1.1 Emergency Response Time

Emergency Response Time is the time elapsed from the initial identification of a loss of electrical power (via a customer call or internal notification) to the arrival of FBC personnel on site at the trouble location. This will provide ongoing information to assess FBC crew sizes and crew locations in response to system trouble.

The measure is calculated as follows:

$$\frac{\text{Number of emergency calls responded to within two hours}}{\text{Total number of emergency calls in the year}}$$

Table D6-3 below summarizes FBC's 2010 - 2012 emergency activity levels (number of calls), average emergency response times, the number of calls greater than two hours, and the overall percentage of emergency response times two hours or less.

Table D6-3: Summary of FBC Emergency Activity Levels and Average Response Time

			Number of calls over two hours	Percent of responses in two hours or less
2010 to 2012	Number of calls	8,730	663	93%
	Average response time	1h 10m		
2012	Number of calls	3,135	287	91%
	Average response time	1h 47m		
2011	Number of calls	2,803	222	92%
	Average response time	59m		
2010	Number of calls	2,792	154	95%
	Average response time	45m		

A slight decrease in the percentage of calls being responded to in two hours or less is evident in the table above. Over the last few years Utility Operations has experienced difficulty in attracting and retaining skilled journeyman Power Line Technicians (PLTs). Part of the duties of these PLTs is to provide emergency on call response in all regions and have a good local knowledge of the area they are working in. These challenges have been particularly evident in our Kootenay and Boundary regions and have contributed towards an increase in response times in these areas.

The 2012 results also reflected an increase in significant weather events between June and August which primarily affected the South Okanagan, Boundary and Kootenay regions. Frequent storms and associated damage to the distribution system led to further increases in response and restoration times for 2012.

On average over the three-year period, the percentage of responses within two hours or less has been 93 percent, very favourable performance compared to FBC's existing benchmark of 85 percent. FBC believes that the current benchmark represents the level of service expected by its customers and proposes to retain its existing benchmark of 85 percent for the term of the PBR.

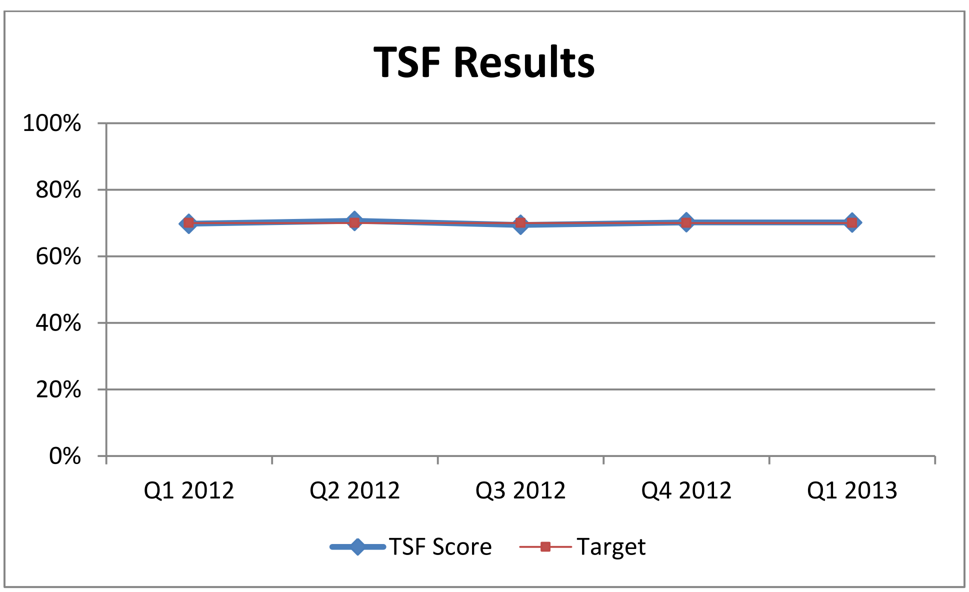
3.2 CUSTOMER SERVICE SQIS

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. FBC believes that TSF is an appropriate contact center metric as it balances costs with service quality.

In 2012, the average service level was on target at 70 percent of calls answered within 30 seconds or less. Quarterly results have been very consistent and are shown in Figure D6-1 below.

Figure D6-1: TSF Results



FBC proposes to continue reporting on TSF and to retain the existing target for electric customer service operations, which is 70 percent of calls answered in 30 seconds or less.

3.2.2 First Contact Resolution (FCR)

First contact resolution (FCR) is an area of focus for FBC as both independent and primary research conducted by FBC 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 and improve the customer experience.

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.[1] Their research supports that FCR is the metric with the highest correlation to customer satisfaction. This conclusion is affirmed through statistical analysis of FBC's own electric customer service survey data.

FBC 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, FBC intends to use the same methodology as is currently in place at the gas contact centers. This will involve using SQM to contact customers who have recently had an interaction with the Company. On average, 90 customers per month will be contacted by SQM, who will ask the customer a number of questions including whether or not their question or issue was resolved. This data, first collected in April 2013, will be compiled into a monthly report providing a score for FCR.

Evidence supports that FCR is an important measure of service quality and as such, FBC believes it should be reported as a service quality metric. The target for the term is proposed at 78 percent which is the current target for the gas utility's operations.

3.2.3 Billing Index

FBC proposes to track the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The proposed Billing Index, which improves on the previous single measure of billing accuracy[2], is a composite index

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[1] SQM Group, reference available at www.sqmgroup.com/first-call-resolution-level-1
[2] FBC previously measured the percentage of bills stopped due to error and delayed beyond the regular billing date.

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 based on input data). The differential between the benchmark and the actual for each is then divided by three to determine the billing index. The objective will be to achieve a score of five of less. The relevant formulas and proposed benchmarks for the three sub-measures, using illustrative results, are presented below.

Table D6-4: Proposed 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)]

Measuring each of the three dimensions will provide FBC with a far more robust way of measuring the level of success within the billing function. FEI currently reports in a similar fashion which has proven to be an effective measure of success. Although FBC has only recently begun collecting this data and does not currently have sufficient history on which to base a target the Company is confident in setting the same target as the gas utility.

3.2.4 Meter Reading Accuracy – Number of Scheduled Meters that were Read

Providing accurate and timely meter reads for customers continues to be a key driver for FBC and as such the Company will continue to report Meter Reading Accuracy, which is the number of scheduled meters read.

The results for the past three years continue to show a steady completion rate of 98 percent.

FBC is proposing to continue with a benchmark of 97 percent.

Table D6-5: Past 3 Years Results for Meter Reading Accuracy

2010	2011	2012	Benchmark
98.3%	97.8%	97.8%	97%

3.3 *INFORMATIONAL INDICATORS*

3.3.1 System Reliability Indicators

FBC proposes to continue measuring transmission and distribution system reliability as adjusted by the Institute of Electrical and Electronics Engineers (IEEE) method of normalizing reliability statistics by excluding "major events". Major events are identified as those that cause outages exceeding a threshold number of customer-interruptions or customer-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data.

The 2.5 Beta method for normalizing utility reliability performance is a generally accepted, statistically based methodology for identifying outlying performance and classifying reliability data into "normal" and "major event" days. Any single outage event that exceeds the threshold value is excluded from the reliability data. Major event days in the FBC service territory have been caused by mudslides, windstorms and wildfires.

Reported outages included in these measures are of one minute duration or longer, which is consistent with the Canadian Electricity Association standard for reporting

3.3.1.1 System Average Interruption Duration Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off per year (i.e. the total amount of time the average customer's clock would lose during a year) calculated as follows:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruption}}{\text{Total Number of Customers Served}}$$

Customer Hours of Interruption related to a power outage are calculated by multiplying the number of customers affected by the outage by the duration of the outage.

3.3.1.2 System Average Interruption Frequency Index (SAIFI) – Normalized

SAIFI is the average number of interruptions per customer served per year (i.e. the number of times the average customer would have to reset their clock during the year) calculated as follows:

$$\text{SAIFI} = \frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers Served}}$$

The Number of Customer Interruptions related to a power outage is the number of customers affected by the outage.

FBC's normalized annual and three year rolling average[3] SAIDI and SAIFI results from 2010 to 2012 are summarized below.

Table D6-6: 2010 – 2012 System Reliability Performance - Normalized

		2010	2011	2012
SAIDI	Annual	2.84	1.86	2.00
	Three-Year Rolling Average			2.24
SAIFI	Annual	2.27	1.38	1.27
	Three-Year Rolling Average			1.64

FBC 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 All Injury Frequency Rate

FBC is committed to continual improvement of corporate safety performance and will report its 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:

All Injury Frequency Rate =

$$\frac{\text{(Number of LTI + MT) x 200,000 hours}}{\text{Exposure Hours}}$$

Following is a summary of FBC's AIFR results from 2010 to 2012.

[3] Three year rolling average calculated by taking the average of the last three years' annual results (i.e. SAIFI 2012 three year average is calculated by taking annual results for 2010 – 2012 (2.27 + 1.38 + 1.27) and dividing by 3 = 1.64)

Table D6-7: 2010 – 2012 AIFR Historical Performance

Year	Lost Time Injuries	Medical Treatments	Annual	Three Year Rolling Average
2010	3	5	1.72	2.00
2011	6	1	1.48	1.54
2012	4	4	1.72	1.64

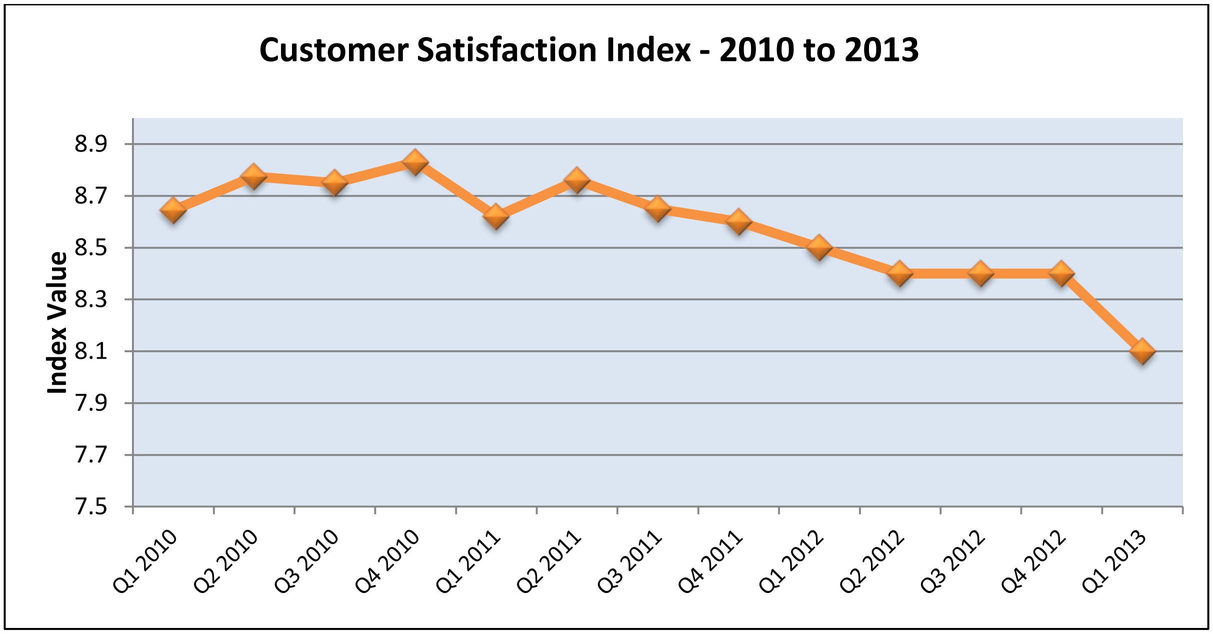
FBC proposes to include this metric as an informational Service Quality indicator as the results are to be considered informational in nature.

3.3.3 Customer Satisfaction Index (CSI)

FBC uses the CSI methodology to evaluate and monitor overall customer satisfaction with the company's electricity service. The CSI is conducted quarterly. Each wave includes 350 telephone interviews with the primary decision makers responsible for paying the electricity bills within their household or business. Lists of active customers are provided to an external research vendor. This vendor uses quota sampling to ensure 300 interviews are residential customers, and 50 are mass market small commercial customers. 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 electric service from FBC; (2) satisfaction with the accuracy of meter reading; (3) satisfaction with energy conservation information; (4) overall satisfaction with the contact center; and (5) overall satisfaction with field services.

FBC proposes to use the customer satisfaction results as a directional indicator, rather than assigning a specific target. This is because customer attitudes are often influenced by factors outside the Company's control. Important examples include storm related unplanned outages, media coverage, and customer concerns about tiered electricity prices or collection policies. As a result, trend information is more valuable and useful than the actual quarterly number. The Company's ongoing review of CSI results suggests that several of these extraneous factors may be adversely affecting recent CSI results. The graph below shows how the overall CSI has performed since 2010.

Figure D6-2: CSI Performance Since 2010



Recent CSI scores by customer type are shown in the table below.

Table D6-8: CSI Scores by Customer Type

Category	Q1 2012	Q2 2012	Q3 2012	Q4 2012	Q1 2013	Margin of Error
Residential	8.4	8.3	8.4	8.4	8.0	± .5
Commercial	8.6	8.8	8.7	8.6	8.5	± 1.2
Total	**8.5**	**8.4**	**8.4**	**8.4**	**8.1**	**± .4**

The decline in the Total CSI metric in Q1 2013 is primarily the result of a decrease in the Residential score for Overall Satisfaction, however all the Index contributors that are noted above fell. This lower score is within the margin of error. Importantly, in-depth analysis of CSI verbatim reveals no discernible service impairment. Rather customers voiced a high level of dissatisfaction with the introduction of the Residential Conservation Rate (RCR), and with electricity rates in general. Several comments alluded to concerns with FBC's pending Automated Metering Infrastructure (AMI) Project.

Growing customer dissatisfaction with RCR and pricing is evident from the increase in the number of comments received in Q1 2013 versus earlier quarters. In Q4, 2012, out of the 21 comments regarding dissatisfaction with price, only 2 were specifically related to the RCR. In Q1, 2013, there were many more comments regarding dissatisfaction with price (54). Almost half of these comments were specifically tied to the RCR.

Recent media attention has also fueled negative perceptions about AMI and this likely further erodes customer satisfaction.

4. SUMMARY OF PROPOSED SERVICE QUALITY INDICATORS

Table D6-9 following summarizes FBC's proposed service quality indicators along with the proposed benchmarks.

Table D6-9: Summary of Proposed Service Quality Indicators

Service Quality Indicator	Benchmark
Emergency Response Time	85% of calls responded to within two hours
Telephone Service Factor	70% of calls answered in 30 seconds or less
First Contact Resolution	78%
Billing Index	5
Meter Reading Accuracy – number of scheduled meters that were read	97%
System Average Interruption Duration Index – Normalized	Informational indicator
System Average Interruption Frequency Index – Normalized	Informational indicator
All Injury Frequency Rate	Informational indicator
Customer Satisfaction Index	Informational indicator

5. DISCONTINUED SQIs

Given the proposed suite of SQIs, FBC believes that some of the existing metrics currently reported provide limited value going forward. Following is a summary of the SQIs being discontinued.

Generator Forced Outage Rate

This measure is indicative of a generator's reliability and is measured as the ratio of forced outages (hours) to total operating time (hours). A Generator Forced Outage means the occurrence of a component failure or other event which requires that the generating unit be removed from service immediately or up to and including the very next weekend.

Residential Connections Completion Time

This indicator tracked the completion time for Residential Standard Connections, which are new customer connections that do not require design or field permitting requirements. Services typically include: meter installs, overhead drops, underground pull-ins and temporary construction services

Residential Extensions Quoting Time

Residential Service Extensions are new customer connections that require multiple pole installations to extend the power line from the existing primary distribution line to the customer's take off point.

This measure tracked the time taken for FBC from initial customer contact to prepare an initial design and to provide a customer quotation.

Residential Extensions Completion Time

This measure tracked the time taken from the customer's acceptance of quote to construction completion with electrical hook up.

Injury Severity Rate

The Injury Severity Rate is a measure of injury severity based on the average number of days lost due to workplace injury or illness per 200,000 hours worked (days lost per approximately 100 workers).

Vehicle Incident Rate

The Vehicle Incident Rate measured the number of vehicle collisions based on licensed fleet motor vehicle incidents that result in injury and/or property damage greater than $1,000 per 1,000,000 kilometres driven.

6. ANNUAL REVIEW PROCESS

At the Annual Review workshop, year to date SQI results along with projected year end results will be presented along with commentary on the results. Discussion of the Company's performance in regard to the SQIs will serve to provide a better understanding of any issues affecting the Company's ability to meet the established benchmarks.

Appendix D7

REFERENCED ACADEMIC PAPERS

Appendix D7-1

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]

Joseph Doucet[b]
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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[b] Enbridge Professor of Energy Policy, CABREE, University of Alberta School of Business.
[c] Emeritus Professor, University of Birmingham, and Fellow, Judge Business School, University of Cambridge.

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

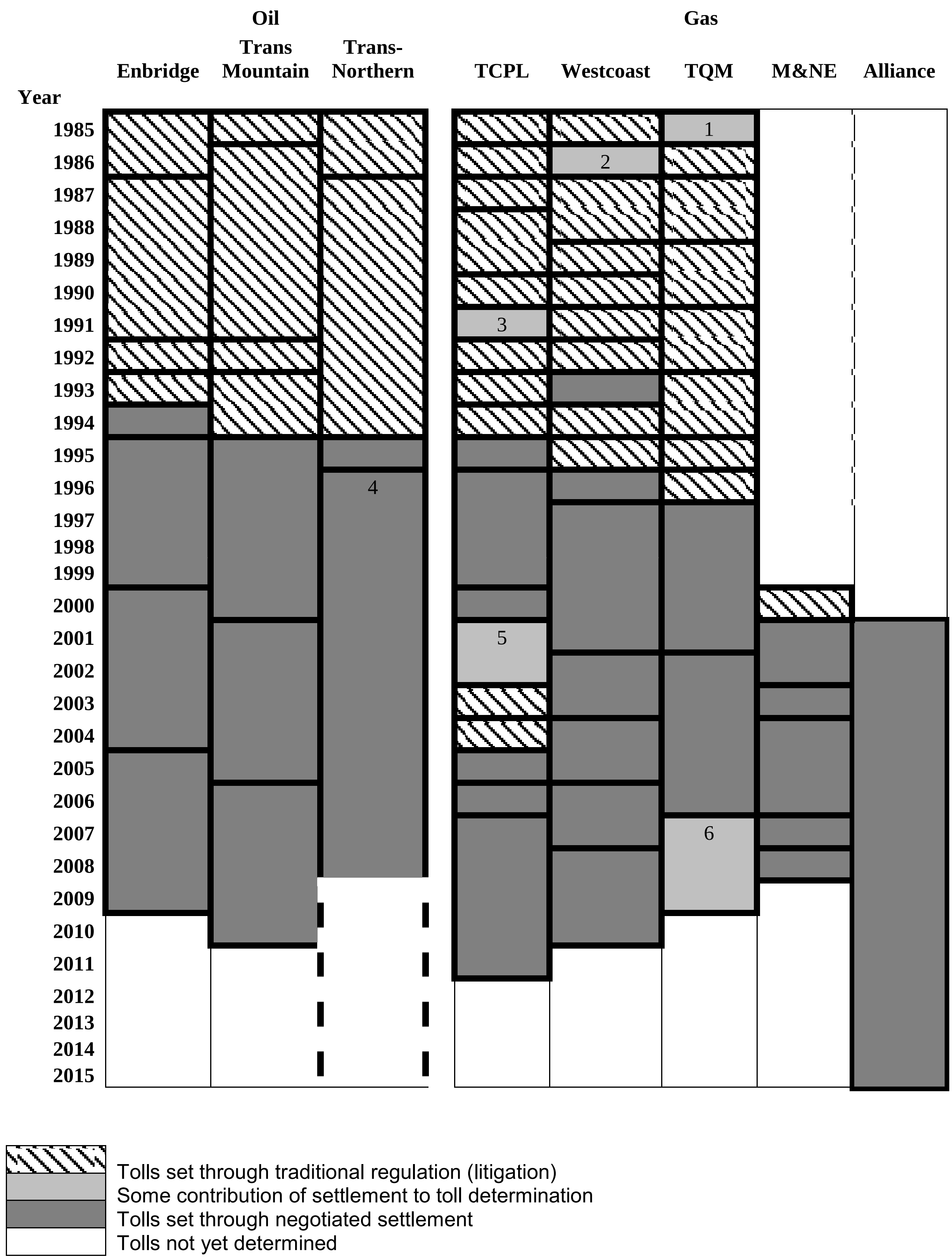
These changes in toll hearings were associated with the development of negotiated settlements. Figure 1 shows the extent to which each pipeline has negotiated settlements over the last two decades, including a few cases where the settlement did not cover all the issues or where the Board did not fully 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



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]

[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.

[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

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[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

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[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.

[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 D7-2

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

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

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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

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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]

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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

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

$$G(X) = K\,(Min[r(X), s] + \alpha(X)\big[r(X) - s\big]^+). \tag{A1}$$

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

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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 D7-3

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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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

[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

[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 D7-4

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

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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

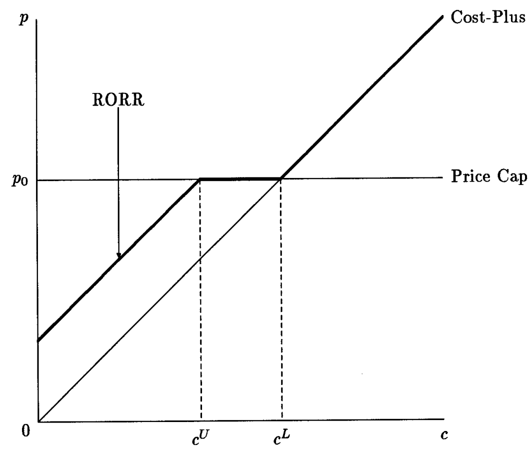

Figure 1. Pricing for Three Benchmark Cases

$$\bar{\pi}(e) = \int_0^{c^U} [(1 - \alpha^U)U + \alpha^U(p_0 - c)q(p_0)]dF(c \mid e) + \int_{c^U}^{c^L} (p_0 - c)q(p_0)dF(c \mid e)$$
$$+ \int_{c^L}^{c_0} [(1 - \alpha^L)L + \alpha^L(p_0 - c)q(p_0)]dF(c \mid e) - \psi(e). \tag{2}$$

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

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 $L \leq 0 \leq U$, 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.

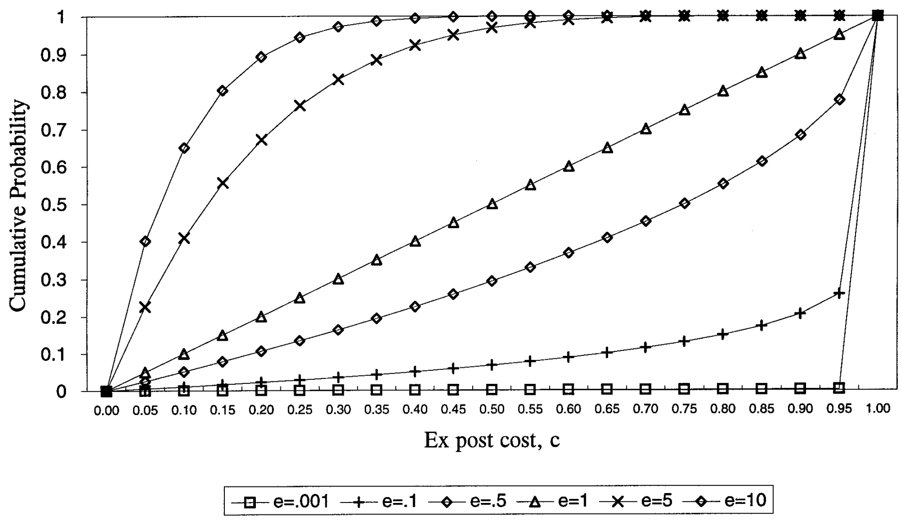

Figure 2. Probability Distribution on Costs for Alternative Effort Levels

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

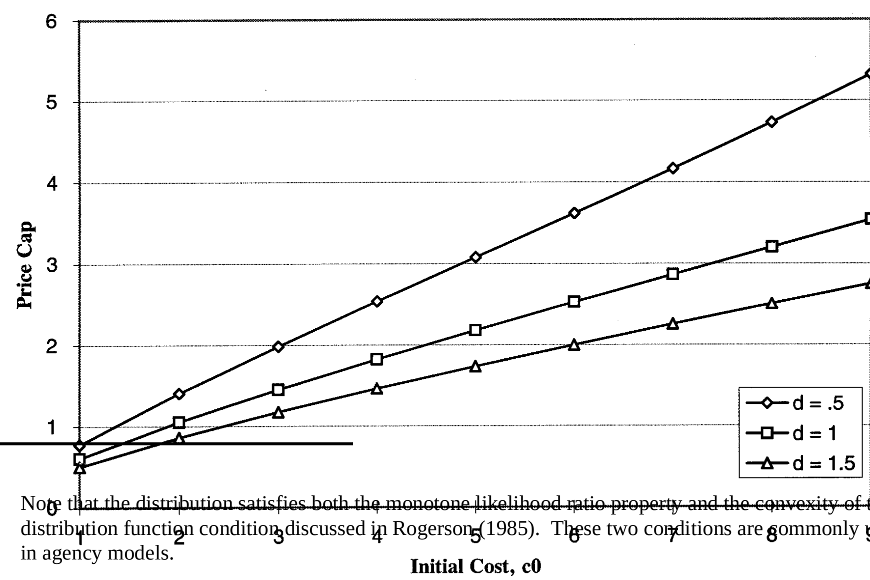

Figure 3. Optimal Price Caps for Various Cost-Reduction Efficiencies

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.

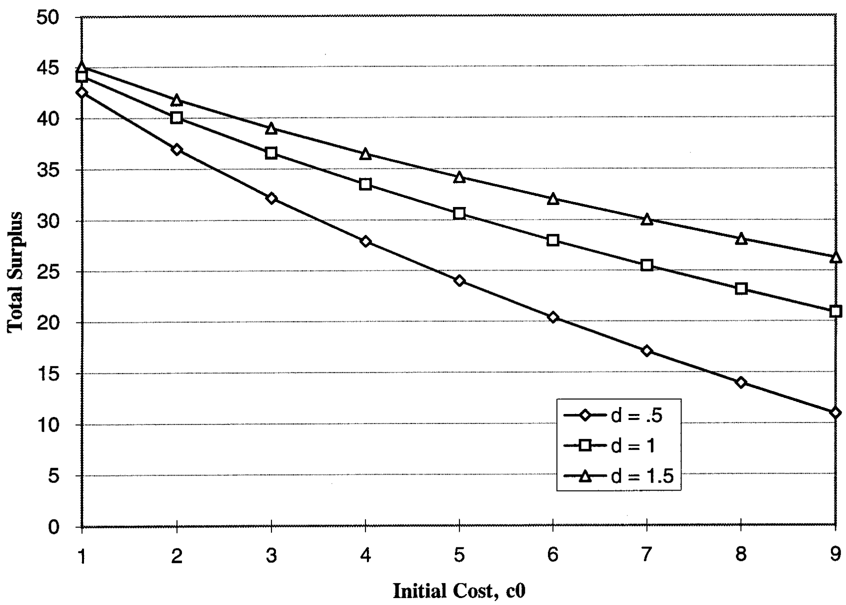

Figure 4. Welfare under Optimal Price Caps

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.

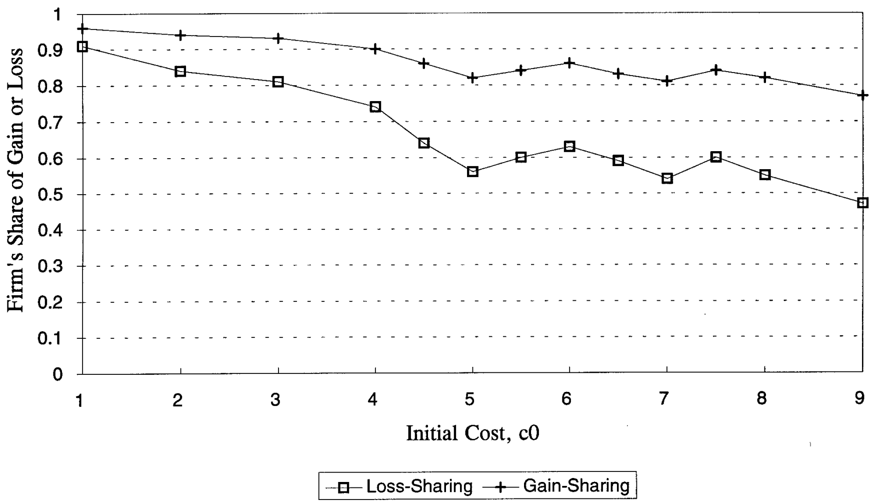

Figure 5. Welfare-Maximizing Sharing Rules ($d = 1$, $L = U = 0$)

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

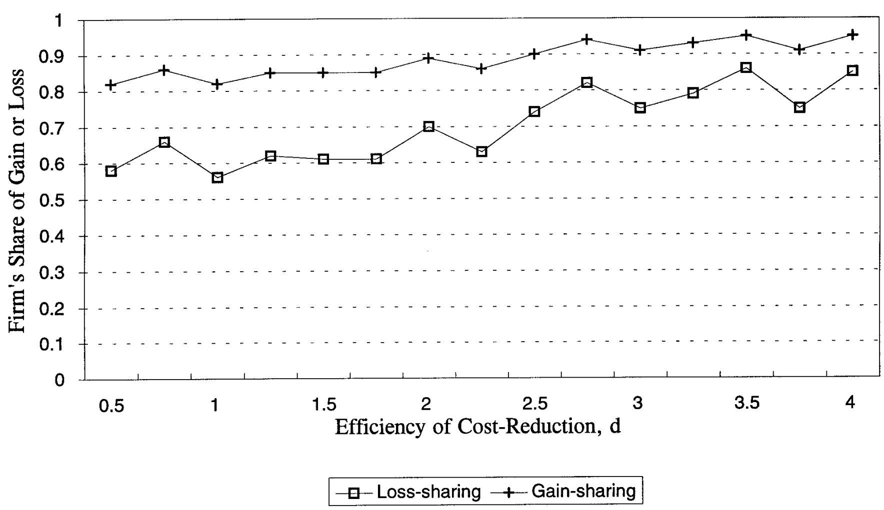

Figure 6. Welfare-Maximizing Sharing Rules ($c0 = 5$, $L = U = 0$)

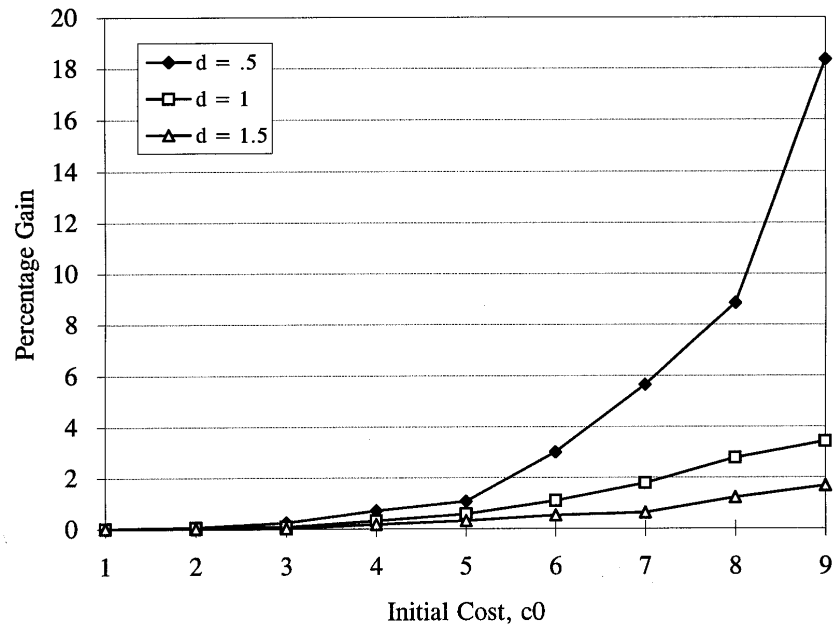

Figure 7. Welfare Gain: Price Caps to Sliding Scale

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 $\overline{\pi}(e,p_0) = \int_0^{c_0} (p_0 - c)q(p_0)dF(c \mid e) - \psi(e)$. Then, by the envelope theorem,

$$\frac{d\overline{\pi}(e^*,p_0)}{dp_0} = \int_0^{c_0} [q(p_0) + (p_0 - c)q'(p_0)]dF(c \mid e).$$

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 $\overline{\pi} > 0$ and if $p_0 = 0$ then $\overline{\pi} < 0$. Since $\overline{\pi}$ is continuous in p_0, there exists some $\underline{p} > 0$ such that $\overline{\pi}(e^*,\underline{p}) = 0$ and $\overline{\pi}(e^*,p) < 0$ 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,

$$\left.\frac{d\overline{W}}{d\alpha^U}\right|_{\alpha^U=0} = \int_0^{c^U} \left[(p^U - c)q'(p^U)\frac{[(p_0 - c)q(p_0) - U]}{q(p^U) + (p^U - c)q'(p^U)}\right]dF(c \mid e)dc$$

$$+ \left.\frac{\partial\overline{W}}{\partial e}\frac{\partial e}{\partial\alpha^U}\right|_{\alpha^U=0}. \tag{13}$$

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

$$\left.\frac{\partial \overline{W}}{\partial U}\right|_{U=0} = (1-\alpha^U)\int_0^{p_0} \frac{(p^U - c)q'(p^U)}{q(p^U) + (p^U - c)q'(p^U)} dF(c \mid e)dc$$

$$< \max_c \frac{(p^U - c)q'(p^U)}{q(p^U) + (p^U - c)q'(p^U)}. \tag{17}$$

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 D8

ALBERTA UTILITIES COMMISSION DECISION 2012 PBR PLAN

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]

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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]

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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

[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

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[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

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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

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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]

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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.

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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

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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:

$$\mathbf{Rates_t = Rates_{t-1} * (1 + I - X) \pm Other\ Adjustments}$$

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:

Revenue per customer$_t$ = Revenue per customer$_{t-1}$ * (1 + I – X) ± 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.

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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]

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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)

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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.

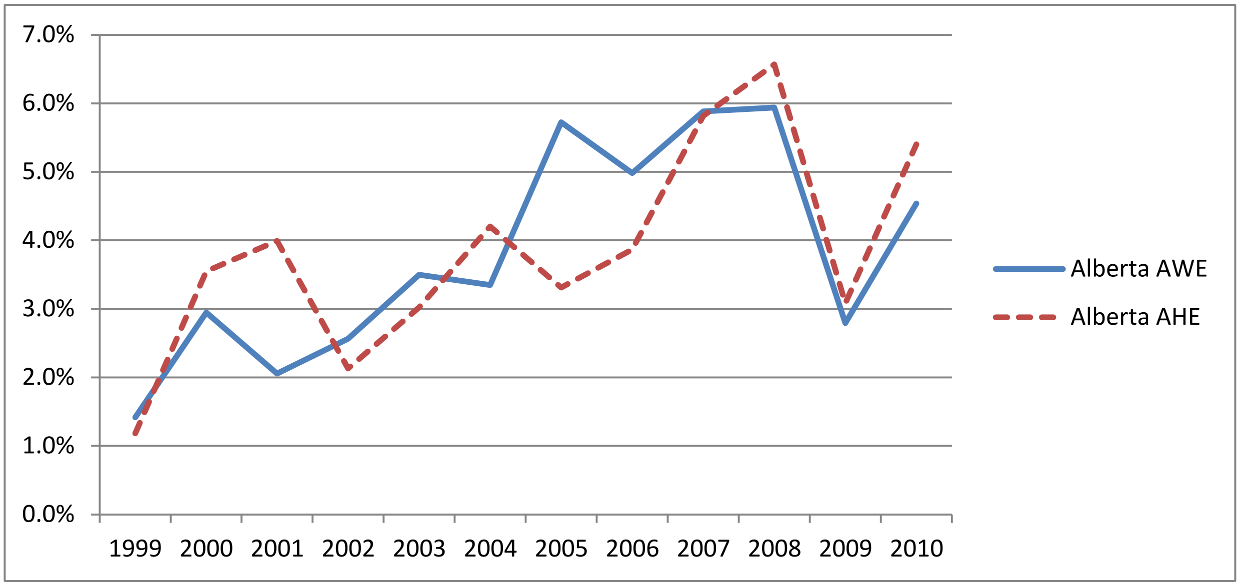
184. In their respective PBR applications, Fortis and EPCOR proposed using the AHE index, defined as average hourly earnings for salaried employees (paid a fixed salary), including overtime and unadjusted for seasonal variation, which is published for selected industries classified using the North American 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:

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'

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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

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.

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

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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,

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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.

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.

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[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.

Commission findings

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]

Commission findings

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]

[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

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

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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:

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

[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

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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

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

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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

[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]

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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.

[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?
>
> 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

[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.

[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

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[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

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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]

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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.

[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]

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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

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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'

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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

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

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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.

[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

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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

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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

[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

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

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[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

[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

[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

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[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:

$$R_t = \underbrace{BR_{t-1}(1 + (I - X))}_{\substack{\text{Base rates} \\ (BR_t)}} +/- Z +/- K +/- Y$$

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:

$$RPC_t = \underbrace{BRPC_{t-1}(1 + (I - X))}_{\substack{\text{Base revenue} \\ \text{per customer class}}} +/- Z +/- K +/- Y$$

$$R_t = RPC_t / BDC_t$$

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
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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
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Name of organization (abbreviation) **counsel or representative**
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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
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South Alta Rural Electrification Association D. Evanchuk B. Bassett

Name of organization (abbreviation) **counsel or representative**
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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

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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 D9

PBR WORKSHOP MATERIALS

PBR Terms and Definitions

Item	Definition
Capital Rebasing	The process of adjusting a utility's rate base by adjusting the opening rate base to actual. This typically occurs outside of the PBR term.
Consumer Dividend	Similar in concept to the Stretch Factor.
Consumer Price Index (CPI)	One of the possible measures used to establish the I-Factor in the PBR Formula
Cost of Service (COS)	Determination of a utility's revenue requirement for a test year based on the sum of its cost of service including a rate of return on rate base.
Earnings Sharing Mechanism (ESM)	An ESM generally establishes a formula for sharing with the utility's customers earnings in excess of (or below) a designated amount.
Exogenous Factors (Y-Factors and Z-Factors)	Factors beyond utility management's control such as regulation or laws.
Going-in Rates/Costs	The starting rates or costs for the implementation of a PBR plan.
Hybrid PBR	Combines elements of PBR such as rate indexing with traditional cost of service elements such as capital trackers, deferral mechanisms, and other discrete adjustments outside the PBR formula.
I-Factor	Also referred to as an inflation factor or an input price index. The I-Factor is the component of a PBR plan that reflects the expected changes in the prices of inputs that the utility uses.
Incentive Regulation	Another term used for PBR.
K-Factor	Also known as a Capital factor. The K-Factor recognizes 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 formula in order to provide for some necessary utility capital expenditures.
Off-Ramps	Provisions that permit parties to request either the termination of the utility's PBR plan before the end of the regulatory control period or to modify the terms of the PBR plan.
PBR	Performance Based Regulation. A form of regulation designed to use rewards and penalties to induce the utility to achieve desired business goals, and the utility is afforded some discretion in achieving the goals.
Price Cap PBR	A PBR plan where an index value is used to adjust a utility's individual rate components by the change in the approved index value for the time period of the PBR plan.

PBR Terms and Definitions

Item	Definition
Productivity Improvement Factor (PIF)	See X-Factor.
Regulatory Control Period	The time period during which the PBR plan applies, with a typical regulatory control period of five years. Also called the PBR term or the PBR period.
Revenue Cap PBR	A PBR plan where an index value is used to adjust a utility's class revenues or components of class revenues by the change in the approved index value for the time period of the PBR plan.
Service Quality Indicator (SQI)	Specific performance measures designed to incent the utility to maintain its current level of service or reliability.
Stretch Factor	An additional percentage sometimes applied to the X-Factor, thereby increasing the overall value for X and thus slowing the growth determined by the I-X PBR formula. Also referred to as a Consumer Dividend.
Total Factor Productivity (TFP)	A method to determine the X-Factor which analyzes the total factor productivity (the ratio of the change in outputs to the change in inputs) of the utility industry.
X-Factor	Also known as the Productivity Improvement Factor. There are many ways to measure productivity including complex econometric measures of total or multi-factor productivity factors or simple measures of changes in outputs and inputs. An X-Factor may also include a Consumer Dividend designed to stretch the utility to be more efficient.
Y-Factor	In a PBR plan, the Y-Factor recognizes those costs that do not qualify for Z-Factor treatment but that should be directly recovered from or returned to customers.
Z-Factor	The Z-Factor (also called an exogenous factor) allowed for an adjustment to the formula to allow for costs or revenues that result from an event outside the control of the utility and for which it has no other reasonable opportunity to recover the costs within the PBR formula.

FortisBC Energy Inc. and FortisBC Inc. 2014 – 2018 Performance Based Ratemaking Plan

Workshop

June 19th, 2013

FORTIS BC™

Workshop Agenda

Topic	Presenter
Introduction and Overview	**Roger Dall'Antonia** *Vice President Strategic Planning, Corporate Development & Regulatory Affairs*
Overview of PBR, B&V's PBR and Total Factor Productivity Reports	**Ed Overcast, Ph.D.** *Director, Management Consulting Division Black & Veatch Corporation*
Break	
Proposed PBR Framework for FEI and FBC	**Dennis Swanson** *Director, Regulatory Affairs – Electric*
FEI Proposals	**Diane Roy** *Director, Regulatory Affairs – Gas*
Closing Comments and Proposed Regulatory Process	**Ed Overcast and Roger Dall'Antonia**

Status of Rate Setting for 2014

FortisBC Energy Inc. (FEI)

- Filed June 10th
- Evidentiary update in July to reflect 2013 permanent rates and any adjustments related to the Rate Schedule 16 Decision

FortisBC Inc. (FBC)

- Target filing last week of June
- GCOC Phase 1 impacts will be incorporated into a proposed rate smoothing mechanism

FortisBC Energy (Vancouver Island) Inc., FortisBC Energy (Whistler) Inc., FortisBC Energy Fort Nelson Division

- Will file rate-setting applications in Q3/Q4 of 2013

FORTIS BC™

From the Commission's Decision in FEI's 2012-2013 RRA

"In British Columbia, PBR, combined with the Negotiated Settlement Process has played a role within the rate setting process of FEI. Starting in 2004 and lasting through 2009 FEI operated in a PBR environment. During this period FEI was very successful as targets were met and the Companies note that shared earnings benefits flowing to customers and shareholders totalled $67.5 million each over the six years.

The Commission Panel is satisfied that there were positive results experienced by both ratepayers and the shareholder over the PBR period*. In addition, the Panel finds there is sufficient evidence to suggest that introducing a PBR environment has the potential to act as an incentive to create productivity improvements."*

FORTIS BC™

PBR Review

- PBR incents utilities to invest in efficiencies, provided a long enough term and a balanced plan is in place
- BC has a solid record of successful PBR
- The success of our PBR plans provides a strong basis for going forward with a similar model for this PBR

- The opportunities and potential results may be different now than then; but the incentive framework in the proposed PBR plan will lead to a similar response from the utilities as in the past

FORTIS BC™

Our PBR Objectives

1. To reinforce our productivity improvement culture while ensuring safety and customer service requirements continue to be met;

2. To create an efficient regulatory process for the upcoming years, allowing the companies to focus on effectively managing business priorities and minimizing costs for customers.

Overview of PBR, B&V's PBR and Total Factor Productivity Reports

Ed Overcast, Ph.D.
Director, Management Consulting Division
Black & Veatch Corporation

FORTIS BC™

BUILDING A WORLD OF DIFFERENCE

19 June 2013

FORTISBC UTILITIES
PERFORMANCE-BASED REGULATION

PBR Workshop 19 June 2013

BLACK & VEATCH
Building a world of difference.

TODAY'S DISCUSSION

- Introduction to Performance-Based Regulation (PBR)
- Comparison of Cost of Service (COS) Regulation and PBR
- Key Elements of a PBR Plan
- Recently Approved PBR Plans in Alberta and Ontario
- PBR Plan and X-Factor

INTRODUCTION TO PERFORMANCE-BASED REGULATION (PBR)

INTRODUCTION TO PBR

- PBR is a form of incentive regulation designed to induce the utility to achieve desired business goals, and the utility is afforded some discretion in achieving the goals.
- The most common theoretical starting points of PBR are Price Cap and Revenue Cap.
- Almost all PBR Plans are some form of Hybrid Plans.
- The overall PBR Plan should reflect the circumstances of the utility.

CONCEPTS AND OBJECTIVES OF PBR

- **A Utility's PBR Plan:**
  - Encourages efficiency and productivity
  - Encourages innovation (new products, new services, new technologies)
  - Maintains service quality
  - Places more emphasis on managing the business and less on the regulatory process

GENERAL PRINCIPLES OF PBR

- The PBR plan should, to the greatest extent possible, align the interests of customers and the utility; customers and the utility should share in the benefits of the PBR plan.
- The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
- The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.
- The PBR plan should maintain the utility's focus on maintaining safe, reliable utility service and customer service quality while creating the efficiency incentives to continue to invest in productivity initiatives.
- The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

THE STARTING POINT FOR PBR

- The PBR plan must have a base year or “going-in” prices or revenue requirement from a test year
- Traditional COS forms the basis for the starting point
- COS is used to determine class rates or class revenue requirements for the initial starting point

BASIC PBR CONCEPTS

- **Price Caps and Revenue Caps**
- **The same basic formula applies:**

  PCI = I-X + Z or RCI=I-X + Z

  - PCI is the Price Cap Index
  - RCI is the Revenue Cap Index
- **I is a measure of inflation (CPI, Producer Price Index (PPI), etc.)**
- **X is a measure of productivity**
  - Total Factor Productivity (TFP)
  - Productivity Improvement Factor (PIF)
  - May include a value for the consumer dividend (stretch factor or customer benefit)
- **Z is a factor for exogenous impacts such as tax changes or other government-mandated costs or other uncontrollable costs**

COMPARISON OF COST OF SERVICE AND PBR

COS, “PURE” PBR, AND “HYBRID” PBR

- Traditional Cost of Service (COS) – Regulator approves all elements of the utility’s cost of service including determining a return on equity and an overall rate of return
- “Pure” PBR – In determining the price or revenue cap, the regulator does not review the utility’s costs or profits, but instead establishes an adjustment to its prices for each year of the regulatory control period
- “Hybrid” PBR – Price or revenue caps are determined in conjunction with COS for the initial price. There are multiple provisions to share the Plan’s risks and to permit cost recovery outside of the basic PBR formula in subsequent years
- Virtually all utility PBR plans are hybrid in structure

COMPARING COS AND PBR – EXAMPLES OF COMBINING THE BEST OF EACH

- Hybrid PBR Plans exist where elements of both COS and PBR are applied to a utility's rates
- The PBR formula is applied to the utility's operating expenses and its capital is adjusted based on actual rate base
- The PBR formula is applied and Rate of Return is adjusted on an annual basis
- The PBR formula is applied and various adjustments are used such as a capital tracker and earnings sharing.

KEY ELEMENTS OF A UTILITY'S PBR PLAN

KEY ELEMENTS OF A UTILITY'S PBR PLAN

- Provide appropriate incentives to encourage superior performance
- Easy to implement, avoid excessive administrative costs
- Readily understandable, acceptable to stakeholders
- Reduce regulatory process

KEY ELEMENTS OF A UTILITY'S PBR PLAN

- The Regulatory Control Period (Term of Plan)
- The PBR formula for an adjustment mechanism- Inflation Factor minus Productivity Factor (X-Factor) and Z-Factor
- Flow through Expenses and Revenues
- Exogenous Factors/"Off-Ramps"
- Earnings sharing mechanisms (including dead-bands)
- Efficiency Carryover Mechanisms
- Inclusion of SQIs
- Frequency and methods of reporting

KEY ELEMENTS OF A UTILITY'S PBR PLAN

- **Measure of inflation**
  - Single measure such as CPI, GDP-PI Local, or national measure
  - Combined measure such as CPI and Wage based measure, Local or national
  - Firm specific measure
- **Measure of productivity: Total Factor Productivity (TFP), Multi-Factor Productivity (MFP), consensus of research, negotiated, include a stretch factor**
- **Elements for inclusion in the Z-Factor**
- **Efficiency carry over mechanism**

RECENTLY APPROVED PBR PLANS IN ALBERTA AND ONTARIO

STRUCTURE OF ALBERTA PBR PLANS

- AUC adopts PBR for Gas and Electric Utilities
- Five (5) Year Term of Plan
- Gas Utility Mechanism- Revenue per customer cap
- Electric Utility Mechanism- Price cap
- I- Factor Determination: Weighted CPI and AWE (Average Weekly Earnings) both for Alberta
- X-Factor Determination: TFP=0.96, Consumer Dividend= 0.2 for a total X=1.16
- All Alberta utilities proposed a negative X-Factor

STRUCTURE OF ALBERTA PBR PLANS

- Z-Factor included in the index subject to materiality measured as 40 basis points on ROE
- K-Factor to reflect major capital requirements included
- Y-Factor to recover pass-through costs not included in the Z-Factor or K-Factor such as AESO costs or Commission-approved costs.
- PBR Plan includes a re-opener provision based on two (2) consecutive years of +/- ROE of 300 basis points or a single year of +/- ROE of 500 basis points

ONTARIO 4TH GENERATION ELECTRIC PBR

- **The PBR Plan consists of three options based on the unique characteristics of the electric distributors (municipal distributors and a large number of different sized utilities)**
- **Terms of the plan differs under the three options with some common provisions and reflect the evolution of PBR Plans over time**
- **The three options are as follows:**
  - The 4th Generation Incentive Regulation (IR)
  - The Custom IR
  - The Annual IR Index

Key Point: As plans evolve a one size fits all approach is not the best option

ONTARIO KEY FEATURES

4th Generation IR

- Term=5 years
- Price Cap Index
- I-Factor- Local Composite

Custom IR

- Term= 5 years
- OEB Review for increase
- Inflation only one factor to be considered in annual adjustment

Annual IR Index

- No Fixed Term
- Price Cap Index
- I-Factor – Local Composite

ONTARIO KEY FEATURES

4th Generation IR

- X-Factor Productivity plus a stretch factor- Zero proposed TFP
- Stretch factors customized ranging from 0.0 to 0.6

Custom IR

- OEB to consider multiple factors including productivity

Annual IR Index

- X-Factor Productivity plus a stretch factor
- Stretch factors customized

ONTARIO KEY FEATURES

- Z- Factor for unforeseen events subject to a materiality test based on size of distributor
- Y- Factor for deferral and variance accounts
- K-Factor for 4^{th} Generation IR only the option to include incremental capital not otherwise included in the plan
- K-Factor not necessary for other two plans because of the nature of the plan

ONTARIO KEY FEATURES

- No earnings sharing
- Off-ramp with +/- 300 basis points on ROE triggering a review or utility initiated review
- Potential to add an Efficiency Carryover Mechanism (ECM)
- SQIs included with performance benchmarking among utilities

ONTARIO GAS PBR

Enbridge Gas Distribution

- Term- 5 years with option for a two year extension
- Revenue cap with average use adjustment
- I- factor- GDP IPI FDD
- No X-factor - uses an inflation coefficient

Union Gas Ltd.

- Term – 5 years
- Price cap with an average use term that converts to essentially a revenue cap
- I-factor- GDP IPI FDD
- X-factor fixed at 1.82% based on agreement

ONTARIO GAS PBR

Enbridge

- Z-factor for non-routine events subject to tests and materiality
- Y-factor for deferral and variance accounts based on a list.
- K-factor none under plan

Union

- Z-factor for non-routine events subject to tests and materiality
- Y-factor for deferral and variance accounts based on a list
- K-factor none under plan

ONTARIO GAS PBR

Enbridge

- Earnings Sharing- asymmetric outside a dead band of 100 basis points above ROE
- Off ramp at +/- 300 basis points on ROE
- No efficiency carryover
- SQRs outside plan

Union

- Earnings sharing- symmetric based on graduated sharing
- No off-ramp based on modified sharing plan
- No efficiency carryover
- SQRs outside plan

THE X-FACTOR AND PBR

THE X-FACTOR IN PBR

- The X-Factor determines the rate of change in prices or revenues relative to inflation (positive X means changes slower than inflation and negative means changes faster than inflation)
- Elements of X-Factor are Total Factor Productivity (TFP) - TFP measures the rate of change in inputs and outputs. Also may include a stretch factor
- TFP study considerations differ for gas and electric

DETERMINATION OF X-FACTORS FOR FORTISBC UTILITIES

- X-Factor determined based on a variety of data
- Analysis included a TFP study for each of gas and electric utility, recently approved X-Factors and the Companies desire to have customers benefit from the plan with rates below inflation

GAS TFP STUDY

- **Based on 95 US LDCs**
  - US data is the only complete data source
  - Companies are comparable for a variety of reasons
- **TFP measures the rate of change in inputs and outputs.**
    - If inputs change faster than outputs TFP is negative.
    - If inputs change slower than outputs TFP is positive.
    - TFP is not a measure of efficiency.
- **Several options for TFP analysis, we chose a straight forward and transparent analysis**

DETERMINING TFP-OUTPUT

- Output Measure: For a gas LDC we know from cost of service analysis that distribution costs are caused by customers and design day capacity
- The correct output measure is a combination of customers and capacity or either customers or capacity

DETERMINING TFP: INPUTS

- Three basic categories of inputs: capital, labor and materials and supplies
- As with output the inputs need to be combined in a composite factor
- To combine the inputs we used the Kahn Method as it is called and accepted at the FERC (US Federal Energy Regulatory Commission)
- This method uses an ex-post measure of capital and a combined measure of labor and materials and supplies

DIRECTIONAL INDICATORS FOR TFP RESULTS

- The logic of TFP results is driven by circumstances of the gas LDCs that are in the process of replacing infrastructure
- Infrastructure replacement increases cost to provide the same output pointing to a negative value for TFP
- The TFP study produces negative values for each measure of output

DETERMINING THE X-FACTOR BASED ON TFP STUDIES

- Determination of the X-Factor is more than just a negative TFP value
- The X-Factor must be determined as part of the whole PBR Plan
- Under the FortisBC PBR Plan, not all capital expenditures are included in the formula because CPCN projects are discrete, lumpy and subject to regulatory review

DETERMINING THE X-FACTOR BASED ON TFP STUDIES

- Since the TFP study uses ex-post capital costs, projects like CPCN are in the input measure for the study but not subject to the revenue cap in the PBR Plan
- The X-Factor of 0.5% includes a very significant and challenging stretch factor
- There are trade-offs in the plan that make the proposed X-Factor too high without an earnings sharing mechanism which protects financial integrity for the utility and provides immediate benefits from cost savings to customers

KEY CONCLUSIONS ON THE X-FACTOR

- The X-Factor determination used inputs that were theoretically sound in the TFP analysis
- It recognized the interrelationships between the X-Factor and other elements of the plan
- It provides immediate benefits to customers in terms of rates below the rate of cost inflation
- It will require the commitment of the Company to a culture of continuous improvement

QUESTIONS AND DISCUSSION

Proposed PBR Framework for FEI and FBC

Dennis Swanson

Director, Regulatory Affairs – Electric

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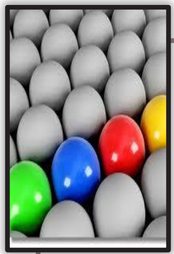
PBR Principles

In No Particular Order

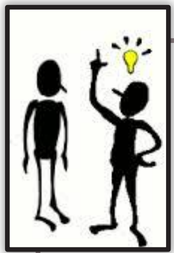
The PBR Plan should align interests of the customer and utility

The PBR Plan should provide an opportunity for utility to recover costs and earn a fair return



The PBR Plan should recognize unique circumstances of the utility and tailor an appropriate PBR

The PBR Plan should maintain safety and quality metrics while providing incentives to increase productivity



The PBR Plan should be simple to understand, easy to implement and minimize the regulatory process

These principles are generally accepted for PBR Plans across North America

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Proposed PBR Term

Base Year — 2013

5-Year PBR Term — 2014, 2015, 2016, 2017, 2018

Benefits

- Provides stable rates for customers over the term of the PBR
- Reduces frequency of regulatory filings

Rationale

- Consistent with many prior BC PBRs
- Many North American PBRs are five years in length

A five-year term allows a utility to realize long-term cost savings that will benefit both customers and shareholders

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Proposed Inflation "I" Factor

PBR Formula Components

The utilities propose a Weighted Composite Inflation Factor that includes both a Labour And Non-labour Component

$$I - Factor = 55\%\underbrace{BC - AWE}_{\text{Labour Component}} + 45\%\underbrace{BC - CPI}_{\text{Non-Labour Component}}$$

Weighting	Labour Component	Non-Labour Component
Reflective of Utility's Cost Structure	**Average Weekly Earnings Index**	**British Columbia Consumer Price Index**

The Companies will provide updated Inflation forecasts of AWE and BC CPI at each Annual Review

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Proposed Productivity Improvement Factor

PBR Formula Components

Proposed 0.5% X-Factor over PBR Period	Results of Black & Veatch's TFP Studies indicate negative productivity gains in recent years for the gas and electric utility industries
	We are proposing a 0.5% X-Factor
	This poses a significant challenge for the Companies

0.5% X-Factor includes a large stretch factor, and is significantly higher than the values produced by the TFP studies

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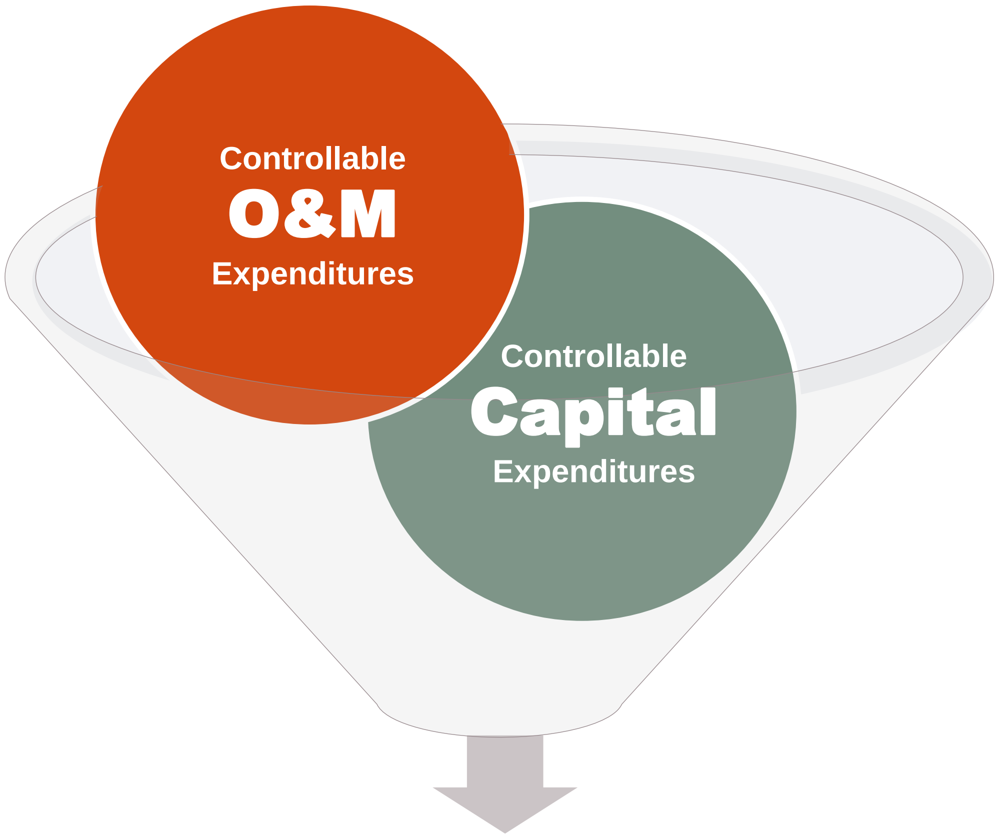
Expenditures Under PBR Formula



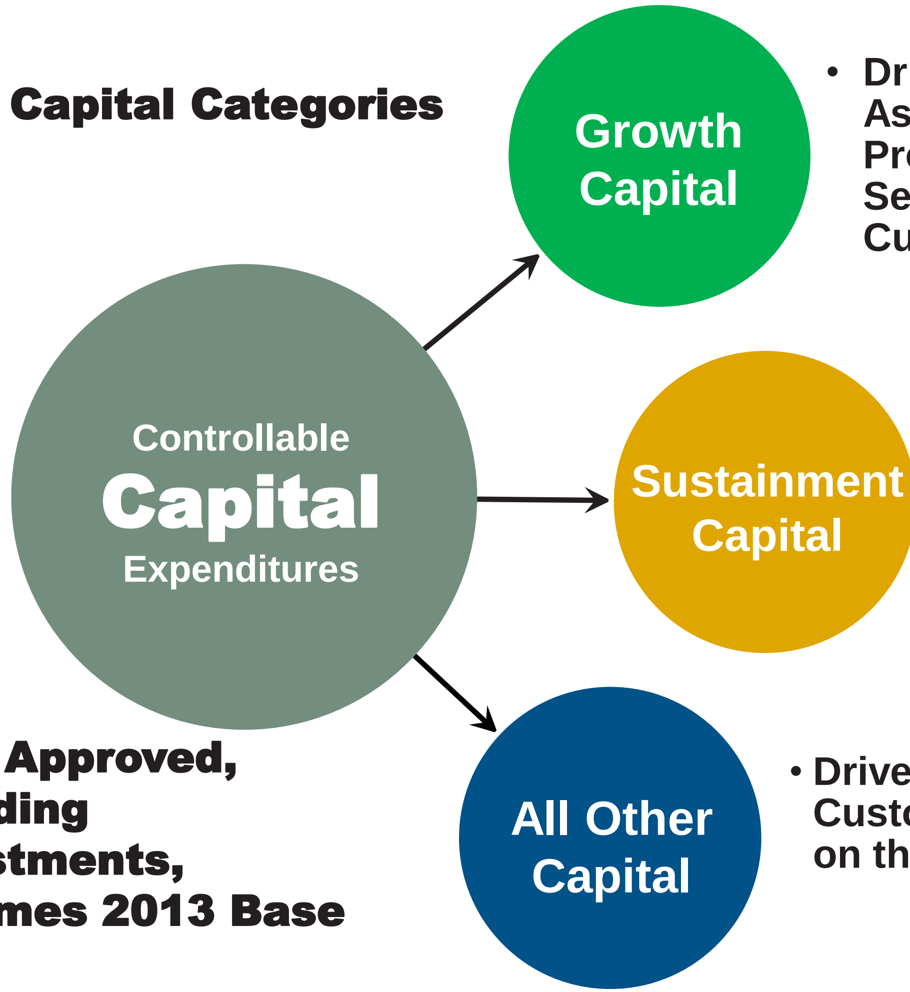
Subject to PBR Formulas

Controllable O&M Expense Under PBR

Escalated annually by the Inflation Factor and forecasted Customer Growth; reduced by the Productivity Improvement Factor

Controllable Capital Expenditures Under PBR

Three Capital Categories



- Driven by Costs Associated with Providing New Service to Customers

- Driven by Number of Customers Served on the System

- Driven by Number of Customers Served on the System

2013 Approved, including Adjustments, becomes 2013 Base

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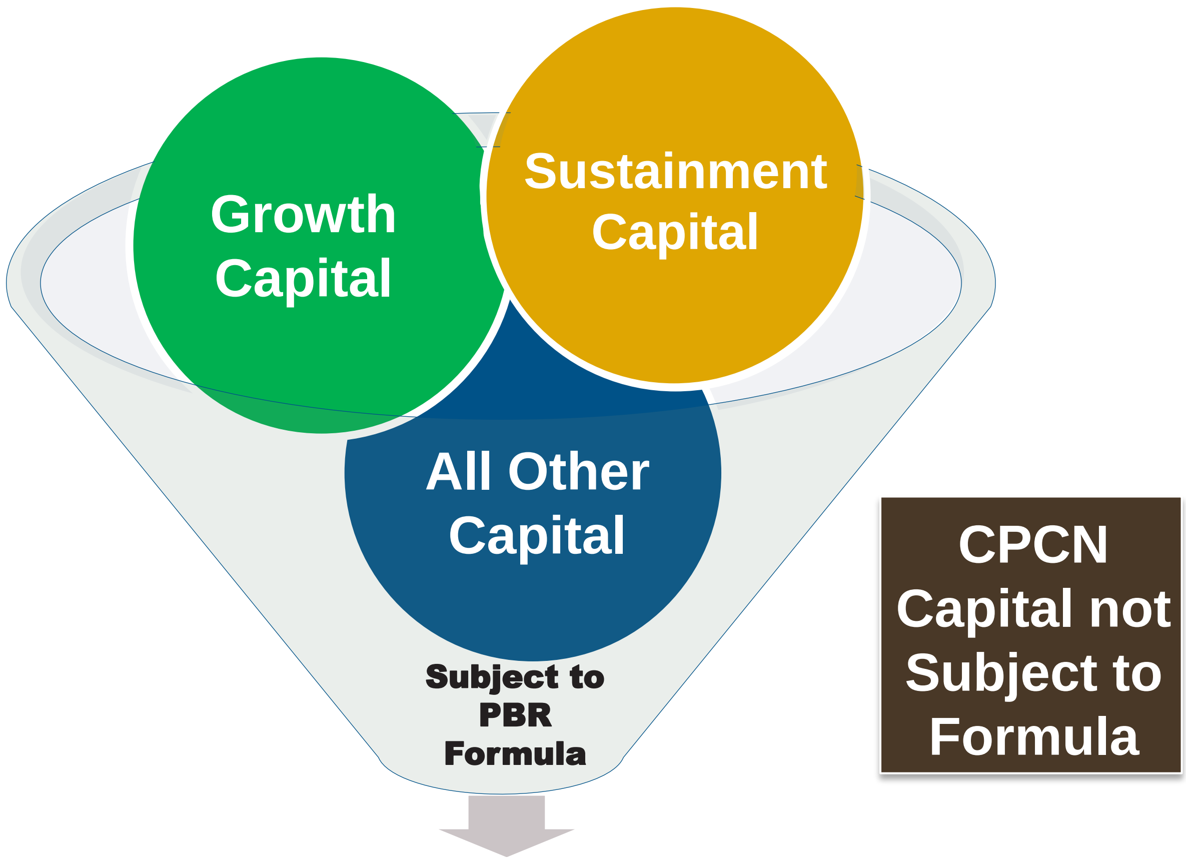
Controllable Capital Expenses Under PBR



Growth Capital Escalated annually by the Inflation Factor and Customer Additions; reduced by the Productivity Improvement Factor

Sustainment and **Other Capital** Escalated annually by the Inflation Factor and forecasted Customer Growth; reduced by the Productivity Improvement Factor

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Non-Controllable Expenses and Revenues

Revenues and Expenses Outside of the Company's Control

Items Are:

- Treated outside of the PBR formula
- Non-controllable items flowed through to customer rates through annual rate setting
- Exogenous factor treatment requested as required

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Non-controllable Items

- Non-controllable items are outside of the Company's control, and therefore not subject to the PBR formula
- These items include expenditures as well as certain revenue items
- The impact from these items are flowed through to customer rates
- These items will be re-forecast each year at the Annual Review
- Examples of flow through items may include:
  - Interest Expense
  - Taxes
  - Revenues
  - Power Purchases (electric)

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Exogenous Factors

- Certain factors cannot be foreseen and are beyond the control of the Company
- Impacts will be reflected outside of the formula-driven rates
- Exogenous factors same as prior plans and include:
  - Judicial, legislative or administrative changes, orders or directions
  - Catastrophic events
  - Bypass or similar events
  - Major seismic events
  - Acts of war, terrorism or violence
  - Changes in accounting standards or policies
  - Changes in revenue requirements due to Commission decisions

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Service Quality Indicators

Metrics:

- Safety
- Customer service
- Reliability

Monitored and reported at Annual Reviews

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Earnings Sharing Mechanism (ESM)

50/50 Sharing with Customers	50% of earnings above or below the allowed level will be shared with customers each year
	Same mechanism as prior PBRs
	Each year, the customers' share of the difference between actual and allowed earnings for the previous year will be forecast; trued up to actual in the following year

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Efficiency Carryover Mechanism (ECM)

Purpose	A rolling five-year period is proposed for phase-out of the incremental capital and O&M benefits
	Provides the same incentive to pursue efficiencies in each year of the PBR term
	O&M and capital savings are included in the calculation

ECM Provides An Incentive For The Company To Maintain A Continuous Improvement Culture

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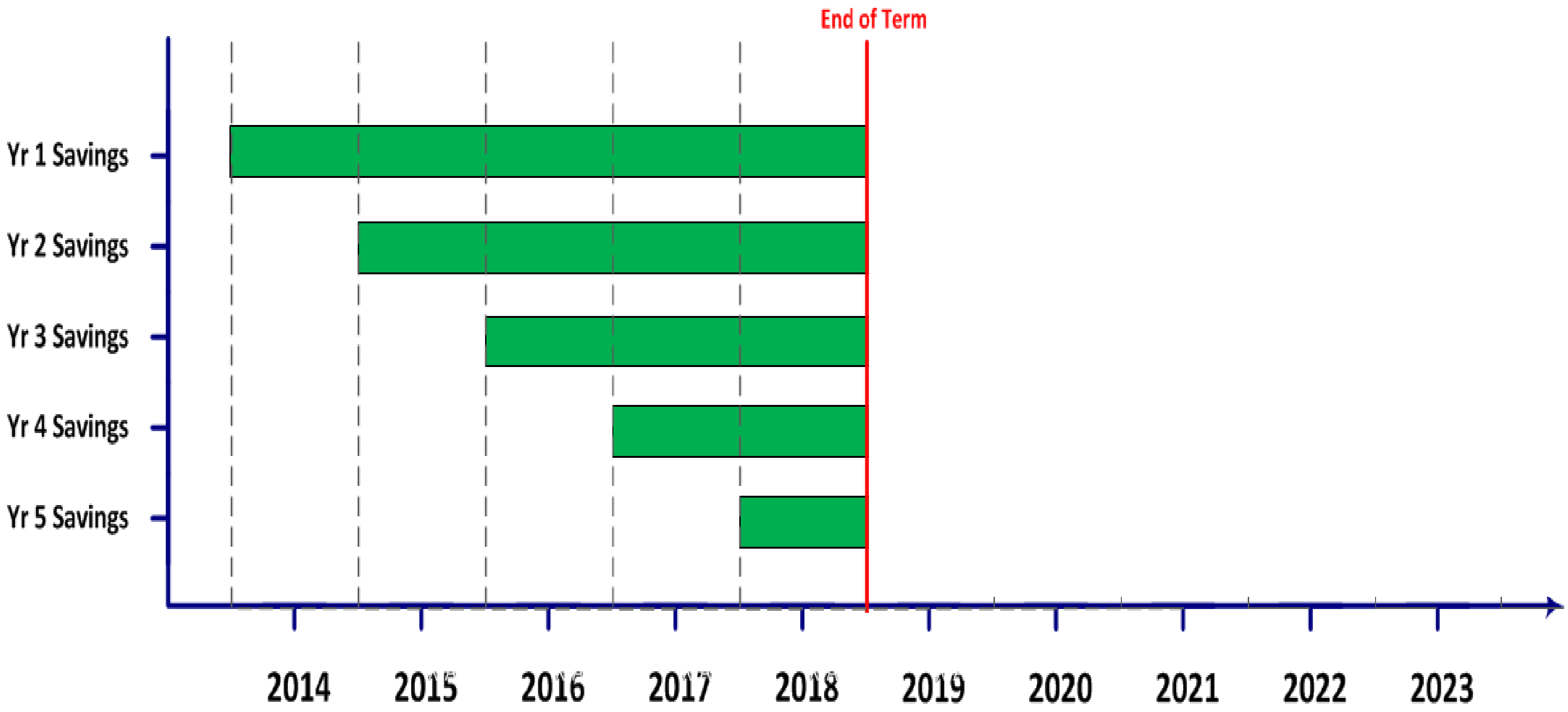
Efficiency Carry Over Mechanism

PBR With Efficiency Carry Over Mechanism Scenario



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Off-Ramp Mechanism

Financial and Non-Financial Triggers	Designed to protect customers and shareholders from unintended unfair outcomes of the PBR plan
	Off-ramps include both financial and non-financial components
	Financial Off Ramp triggered if the difference between the achieved and allowed ROE is greater than 200 basis points in a single year of the plan
	Non-Financial Off Ramp may be triggered if there is serious, sustained and unjustified degradation of the SQI metrics within the Company's control

The impact to customers and the shareholder must be considered and balanced against the effect of triggering an off-ramp

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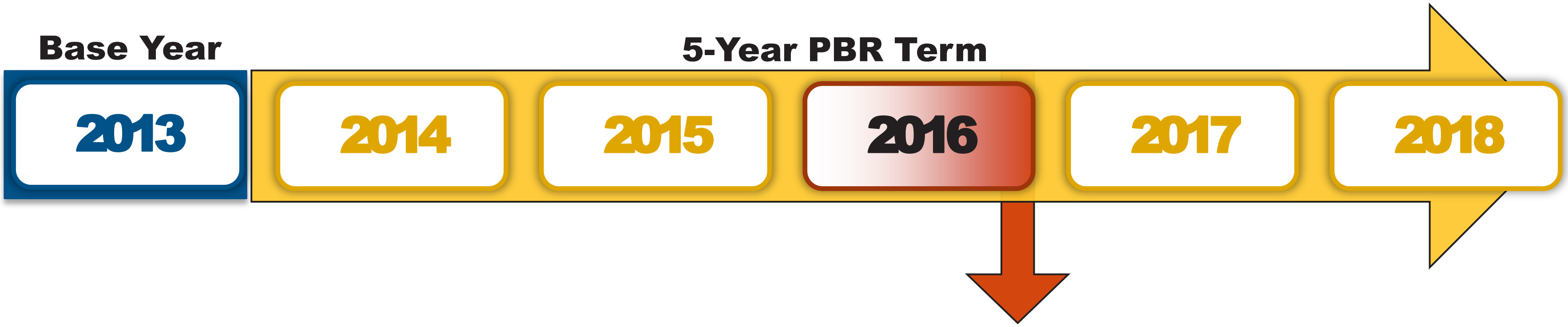
Mid-Term Review



Mid-Term Review: End of 2016

- To provide an opportunity for parties to review the status of the PBR
- To address specific, discrete elements of PBR Plan
- To adjust PBR if certain circumstances occur

Plan only adjusted to address material unintended consequences or material changes in service quality

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Annual Review

Purpose:	**Monitor performance**
	Update projections for the current year
	Provide key forecasts for the following year **(i.e. demand/load, customer additions, deferrals)**
	Provide rate proposals for the following year
	Identify anticipated challenges and issues

The Annual Reviews will be held in the fall, and will consist of a Workshop, one round of IRs, Letters of Comment and a Commission determination on Rates

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FEI Proposals

Diane Roy
Director, Regulatory Affairs – Gas

FEI 2004 – 2009 PBR Results

Productivity Improvement Factor (PIF)	+ O&M Savings	+ Capital Savings
• 7.5 percent decrease in gross O&M • Cumulative O&M benefit of ~$45 million during the PBR term • PIF savings all to customers during the PBR term and rebased after the term	• Cumulative ~$87 million above PIF • Half to customers during PBR term • Savings are rebased into opening O&M after the term	• Benefit ~$50 million above PIF • Half to customers during PBR term • Savings are rebased into opening rate base after the term for ongoing customer benefit

Efficiencies attained to meet and to exceed the productivity improvement targets were achieved without degradation in the quality of service

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Base O&M for FEI

		($ thousands)
2013 Decision		**236,003**
Sustainable Savings		(14,670)
<u>2013 Deferrals:</u>		
PST (full year impact)	762	
BCUC Fees & Insurance	1,016	
Pension (O&M portion)	10,605	12,383
<u>Accounting Changes:</u>		
Allocation of retiree pension/OPEBs	(930)	
Capitalization of annual software costs	(1,800)	(2,731)
2013 Base		**230,985**

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Base Capital for FEI

		($ thousands)
2013 Decision		**117,298**
2013 Deferrals:		
PST (capital portion)	1,999	
Pension (capital portion)	1,311	3,310
Accounting Changes:		
Allocation of retiree pension/OPEBs	930	
Capitalization of annual software costs	1,800	
Vehicles purchased instead of leased	2,860	5,589
2013 Base		**126,197**

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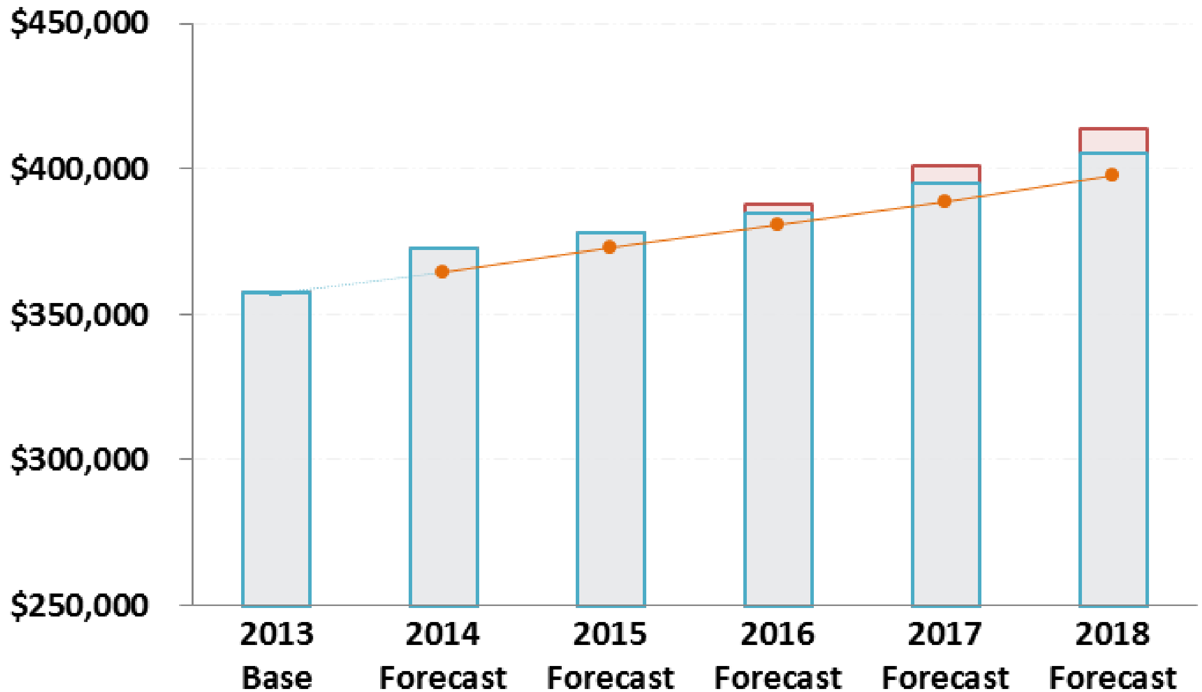
Formula O&M and Capital vs. Cost of Service



	2013 Base	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast
TC High Construction Cost Forecast	$357,182	$372,623	$378,175	$387,585	$400,953	$413,965
TC Low Construction Cost Forecast	$357,182	$372,623	$378,175	$384,477	$395,265	$405,386
TC Under PBR	$357,182	$364,272	$372,709	$380,610	$388,363	$397,516

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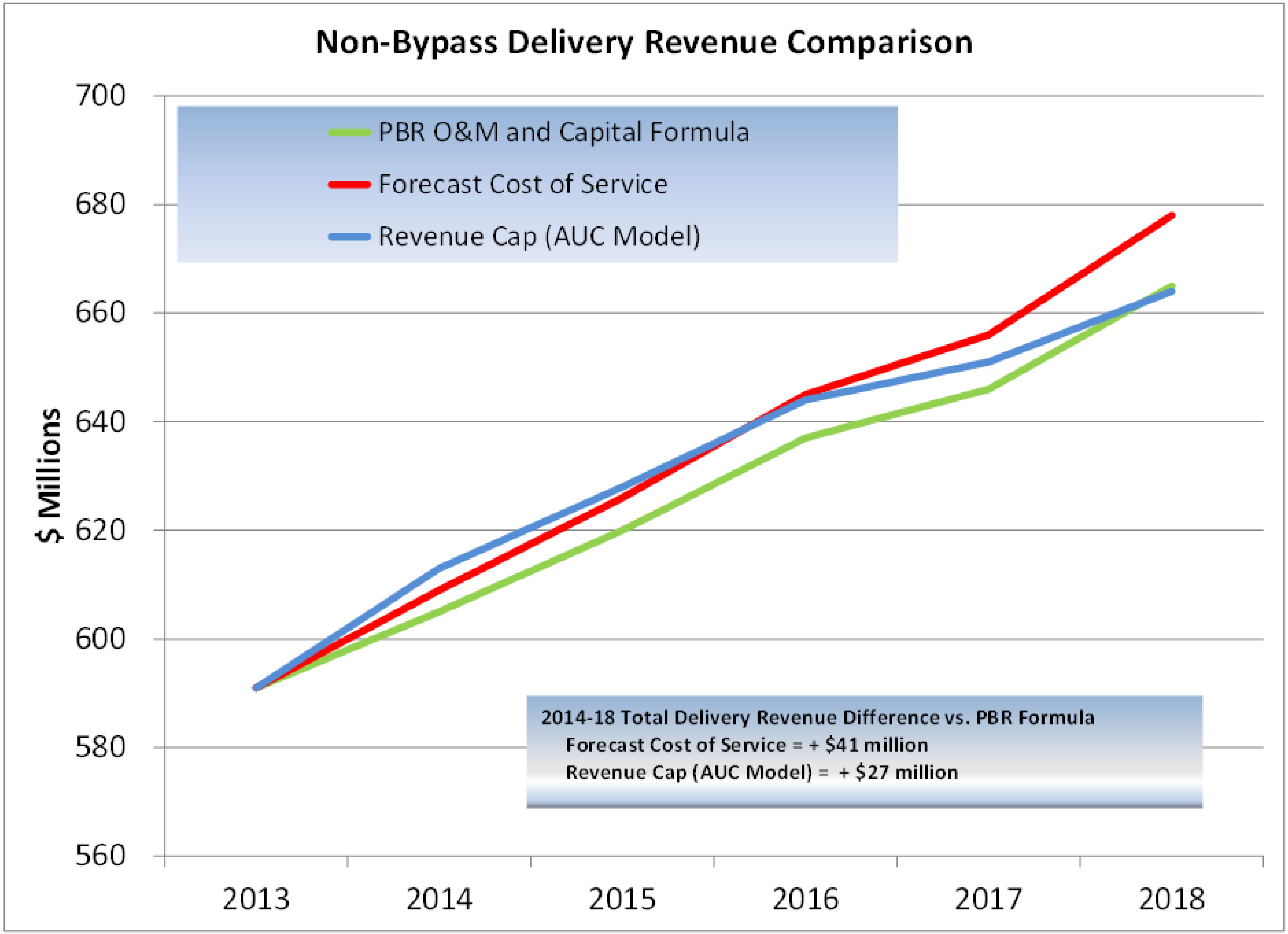
FEI Delivery Revenue Impacts



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FEI Requests in this Application

- Approval of the PBR mechanism for 2014-2018
- Delivery rate increase of 0.7% for 2014
- RSAM rate rider credit of $0.118/GJ
- Deferrals - 2 new, 11 changed, 16 discontinued
- 7 accounting related changes
- Shared services allocations to FEVI and FEW
- Corporate services fee from FortisBC Holdings Inc.
- EEC approvals for FEI, FEVI, FEW

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Closing Comments and Proposed Regulatory Process

Ed Overcast and Roger Dall'Antonia

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THE FORTISBC UTILITIES PBR PLAN

- Overall the plan is sound
- It uses an improved composite measure of inflation
- It includes a positive X-factor when logic suggests that even zero might be a stretch
- The plan correctly focuses on controllable costs and provides for reasonable recovery of uncontrollable, unforeseeable and unpredictable costs
- The inclusion of earnings sharing and efficiency carryover provide added benefits to stakeholders

THE FORTISBC UTILITIES PBR PLAN MEETS THE PRINCIPLES FOR PBR

- The PBR plan should, to the greatest extent possible, align the interests of customers and the Utility; customers and the utility should share in the benefits of the PBR plan.
- The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
- The PBR plan should recognize the unique circumstances of the Company that are relevant to the PBR design.
- The PBR plan should maintain the utility's focus on maintaining, safe, reliable utility service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.
- The PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

Proposed Regulatory Process

ACTION	DATE (2013)
Workshop	June 19
Commission Information Request No. 1 to FEI	July 8
Intervener Information Request No. 1 to FEI	July 15
FEI Response to Information Requests No. 1	August 15
Commission Information Request No. 2 to FEI	August 30
Intervener Information Request No. 2 to FEI	August 30
FEI Response to Information Requests No. 2	September 20
Negotiated Settlement Process or Hearing if Required (proposed date range)	October 1 to October 21
FEI Final Argument Submissions (if required)	November 1
Intervener Final Argument Submissions (if required)	November 8
FEI Reply Argument Submissions (if required)	November 15
Anticipated Decision	December 4

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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 the Summary of General Assumptions page of this appendix for detailed information for 2008-2018.

2 INFLATION

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.

Review of History

In the 2007 PBR Plan, the BC CPI inflation forecast was determined by the average of the forecasts from reputable industry sources: Conference Board of Canada, B.C. Ministry of Finance, the Toronto-Dominion Bank, and the Bank of Montreal (which replaced the Royal Bank of Canada forecast in 2010). In this Application, FBC has also included forecasts from the Canadian Imperial Bank of Commerce and the Royal Bank of Canada to provide two more reputable industry sources which will further increase the precision of an average BC CPI inflation forecast.

Table E-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	March 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

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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											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%	2.10%	2.10%	N/A
3		RBC Financial Group											1.60%	N/A	N/A	N/A	N/A
4		Toronto Dominion Bank											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%	2.20%	-1.10%	0.93%	1.90%	0.97%	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																	
13	CPI/AWE												2.31%	2.42%	2.34%	2.36%	2.30%
14																	
15	Productivity Factor									0.00%			0.50%	0.50%	0.50%	0.50%	0.50%
16																	
17	Average Customers [1]									128,796			129,770	130,922	132,142	133,385	134,687
18																	
19	Customer Growth												0.76%	0.89%	0.93%	0.94%	0.98%
20																	
21	Income Tax Rate:	Federal					15.00%	15.00%		15.00%	15.00%		15.00%	15.00%	15.00%	15.00%	15.00%
22		Provincial					10.00%	10.00%		10.00%	10.00%		10.00%	10.00%	10.00%	10.00%	10.00%
23			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%
24																	
25	Foreign Exchange Rate:																
26		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
27		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
28																	
29	Cost of Capital:																
30		**FBC**															
31		Weighted Average Cost of Debt	6.45%	6.65%	6.40%	6.15%	5.92%	5.00%	1.40%	5.79%	5.87%	0.08%	5.79%	5.53%	5.58%	5.59%	5.59%
32		Return on Equity	9.28%	9.41%	9.65%	10.67%	10.52%	9.90%	-0.25%	9.15%	9.90%	0.75%	9.15%	9.15%	9.15%	9.15%	9.15%
33																	
34	Note [1] Average customers in 2013 adjusted for City of Kelowna additions																

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

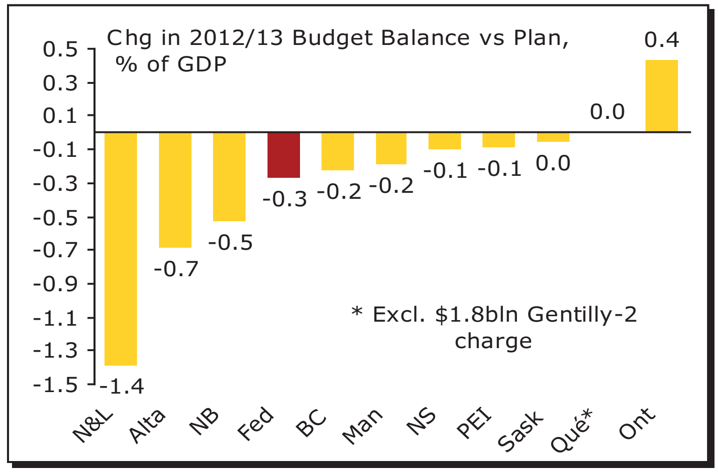
		2007	2008	2009	2010	2011	2012	2013F	2014F
Real GDP	Chained $2007 millions	51,964	54,776	52,567	54,854	57,536	58,917	60,596	62,862
	% change		5.4	-4.0	4.4	4.9	2.4	2.9	3.7
Employment	thousands	504	513	519	524	526	537	552	561
	% change	2.4	1.7	1.3	0.9	0.3	2.1	2.7	1.6
Unemployment rate	%	4.2	4.1	4.8	5.2	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.

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.

Chart 6

Revisions to 2012/13 Budget Plans: Ontario Holding Up Better



Source: CIBC, Provincial governments

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

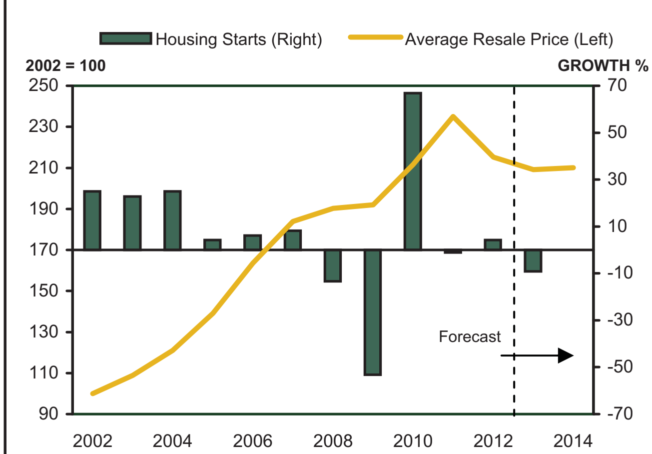
	Real GDP Yr/Yr % Chg			Employment Yr/Yr % Chg			Unemployment Rate %			Housing Starts 000s Units			Consumer Price Index Yr/Yr % Chg		
	2012E	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F	2012A	2013F	2014F
BC	2.1	1.6	2.4	1.7	0.8	1.5	6.8	6.7	6.3	27.5	22.0	21.3	1.1	0.8	1.8
Alta	3.4	2.3	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.

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.

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

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				2013				2014				2011	2012	2013	2014
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4				
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

LOAD FORECAST

1. MONTHLY LOAD FORECAST

Loads (in MWh) shown in the following tables reflect the reclassification of customers and loads that resulted from FBC's acquisition of the electric utility assets of the City of Kelowna, effective March 31, 2013 (wholesale load has been redistributed to other classes of direct customers).

As requested by the Load Forecast Technical Committee in the 2012-2013 RRA, forecast loads are shown:

- *before-saving* – the load before DSM and all other savings (RCR[1], CIP[2], AMI[3], and rate-driven impacts),
- *before-saving and after rate-driven and RCR impacts* – the load before DSM and some savings (CIP, AMI), but after rate-driven and RCR impacts, and
- *after-saving* –the load after DSM and all other savings (RCR, CIP, AMI, and rate-driven impacts).

1.1 GROSS

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	372,584	321,421	310,070	260,041	249,513	242,711	285,398	272,087	239,687	274,284	315,924	376,116	3,519,837
2014	375,205	324,805	315,110	265,809	255,777	247,944	290,387	275,135	243,972	278,861	319,255	378,191	3,570,452
2015	378,917	328,110	318,273	268,538	258,433	250,567	293,361	277,955	246,520	281,683	322,473	381,899	3,606,730
2016	382,606	331,371	321,396	271,214	261,034	253,129	296,292	280,723	249,007	284,454	325,652	385,604	3,642,483
2017	386,039	334,364	324,274	273,647	263,387	255,432	298,966	283,235	251,241	286,979	328,579	389,081	3,675,223
2018	390,160	338,020	327,773	276,656	266,319	258,327	302,268	286,355	254,050	290,092	332,141	393,214	3,715,375
Before-saving & After Rate-driven and RCR Impacts													
2013	371,805	320,748	309,418	259,493	248,986	242,200	284,798	271,516	239,183	273,708	315,262	375,330	3,512,446
2014	373,706	323,534	313,863	264,777	254,791	247,004	289,259	274,084	243,052	277,781	317,999	376,659	3,556,507
2015	376,727	326,288	316,464	267,067	257,036	249,257	291,753	276,480	245,246	280,147	320,662	379,633	3,586,759
2016	379,714	328,988	319,019	269,297	259,221	251,443	294,195	278,819	247,373	282,455	323,277	382,593	3,616,393
2017	382,435	331,412	321,318	271,278	261,151	253,365	296,374	280,894	249,242	284,510	325,632	385,313	3,642,922
2018	385,829	334,487	324,227	273,825	263,651	255,872	299,170	283,568	251,678	287,143	328,610	388,674	3,676,735
After-saving													
2013	371,767	320,425	308,871	258,700	247,980	240,949	283,315	269,738	237,134	271,439	312,763	372,614	3,495,695
2014	371,041	320,726	311,050	261,906	251,892	243,985	286,140	270,761	239,582	274,262	314,417	373,049	3,518,812
2015	372,980	322,404	312,604	263,179	253,145	245,242	287,618	272,116	240,726	275,575	316,020	374,958	3,536,566
2016	374,924	324,061	314,144	264,419	254,362	246,457	289,075	273,441	241,829	276,861	317,611	376,897	3,554,080
2017	377,057	325,808	315,801	265,702	255,599	247,653	290,587	274,783	242,910	278,196	319,309	379,079	3,572,483
2018	379,571	327,975	317,833	267,371	257,238	249,285	292,519	276,554	244,418	279,926	321,405	381,599	3,595,695

[1] FBC's Residential Conservation Rate
[2] Customer Information Portal
[3] Advanced Metering Infrastructure

1.2 NET

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	337,318	292,136	284,910	241,380	232,726	226,308	263,825	252,349	223,665	254,249	289,147	340,237	3,238,250
2014	339,864	295,271	289,472	246,585	238,390	231,064	268,354	255,207	227,595	258,428	292,252	342,334	3,284,816
2015	343,233	298,275	292,379	249,114	240,861	233,501	271,100	257,821	229,967	261,043	295,198	345,700	3,318,192
2016	346,579	301,237	295,250	251,595	243,282	235,884	273,806	260,387	232,284	263,611	298,109	349,059	3,351,084
2017	349,689	303,958	297,894	253,852	245,475	238,028	276,276	262,717	234,369	265,953	300,788	352,206	3,381,205
2018	353,428	307,280	301,111	256,642	248,204	240,720	279,324	265,609	236,985	268,839	304,050	355,955	3,418,145
Before-saving & After Rate-driven and RCR Impacts													
2013	336,612	291,524	284,311	240,871	232,234	225,831	263,270	251,820	223,194	253,714	288,541	339,526	3,231,450
2014	338,500	294,112	288,326	245,629	237,473	230,190	267,312	254,234	226,740	257,428	291,100	340,941	3,271,986
2015	341,234	296,608	290,717	247,754	239,567	232,287	269,616	256,458	228,785	259,624	293,536	343,632	3,299,819
2016	343,934	299,056	293,064	249,826	241,604	234,324	271,873	258,629	230,771	261,766	295,928	346,306	3,327,082
2017	346,389	301,252	295,176	251,667	243,408	236,118	273,888	260,557	232,520	263,676	298,081	348,756	3,351,488
2018	349,460	304,040	297,850	254,031	245,740	238,451	276,471	263,039	234,792	266,120	300,806	351,796	3,382,596
After-saving													
2013	336,755	291,368	283,953	240,254	231,414	224,775	262,029	250,293	221,400	251,744	286,385	337,217	3,217,588
2014	336,408	291,815	286,029	243,215	235,018	227,604	264,691	251,396	223,730	254,427	288,092	338,002	3,240,427
2015	338,339	293,476	287,613	244,527	236,313	228,888	266,195	252,780	224,909	255,781	289,708	339,917	3,258,446
2016	340,281	295,124	289,191	245,816	237,581	230,138	267,686	254,141	226,055	257,116	291,320	341,866	3,276,316
2017	342,417	296,874	290,891	247,155	238,878	231,382	269,240	255,531	227,192	258,509	293,046	344,058	3,295,172
2018	344,880	298,988	292,922	248,840	240,536	233,019	271,168	257,305	228,714	260,255	295,121	346,538	3,318,288

1.3 RESIDENTIAL

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	144,353	115,100	117,062	102,475	95,764	87,095	111,936	99,949	83,947	106,786	129,654	169,829	1,363,950
2014	162,738	129,759	131,972	103,098	96,320	86,674	112,865	99,379	83,066	107,083	130,532	172,958	1,416,442
2015	163,928	130,708	132,937	103,852	97,024	87,308	113,690	100,106	83,673	107,866	131,486	174,222	1,426,800
2016	165,216	131,736	133,982	104,669	97,787	87,994	114,584	100,893	84,331	108,714	132,520	175,592	1,438,016
2017	166,579	132,822	135,087	105,532	98,593	88,720	115,529	101,725	85,026	109,610	133,613	177,040	1,449,875
2018	167,990	133,948	136,231	106,426	99,429	89,471	116,508	102,587	85,747	110,539	134,745	178,540	1,462,160
Before-saving & After Rate-driven and RCR Impacts													
2013	144,023	114,838	116,795	102,267	95,569	86,920	111,708	99,748	83,779	106,569	129,391	169,479	1,361,086
2014	161,897	129,089	131,290	102,566	95,822	86,226	112,281	98,866	82,636	106,530	129,857	172,064	1,409,123
2015	162,458	129,536	131,745	102,921	96,154	86,525	112,671	99,208	82,923	106,899	130,307	172,660	1,414,006
2016	163,107	130,054	132,271	103,332	96,538	86,870	113,121	99,605	83,254	107,326	130,828	173,350	1,419,657
2017	163,819	130,622	132,849	103,784	96,960	87,250	113,615	100,040	83,618	107,794	131,399	174,107	1,425,855
2018	164,569	131,220	133,457	104,259	97,404	87,649	114,135	100,497	84,000	108,288	132,001	174,904	1,432,381
After-saving													
2013	144,320	114,986	116,881	102,207	95,431	86,693	111,466	99,393	83,305	106,060	128,842	168,936	1,358,518
2014	161,639	128,663	130,870	102,022	95,251	85,595	111,730	98,206	81,859	105,805	129,182	171,527	1,402,350
2015	162,039	128,911	131,138	102,167	95,374	85,676	111,933	98,339	81,910	105,963	129,445	171,985	1,404,881
2016	162,573	129,267	131,516	102,397	95,577	85,830	112,229	98,555	82,032	106,211	129,815	172,584	1,408,584
2017	163,605	130,020	132,297	102,944	96,077	86,250	112,870	99,075	82,408	106,786	130,584	173,710	1,416,626
2018	164,380	130,570	132,872	103,329	96,425	86,535	113,335	99,440	82,655	107,193	131,147	174,564	1,422,447

1.4 COMMERCIAL

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	63,621	61,766	58,332	62,746	63,190	65,058	68,855	67,398	63,369	64,557	69,659	72,536	781,088
2014	74,888	72,705	68,662	64,539	65,652	67,946	71,055	69,362	65,913	66,015	70,270	71,510	828,517
2015	76,383	74,156	70,032	65,827	66,962	69,302	72,473	70,746	67,228	67,332	71,673	72,937	845,050
2016	77,809	75,540	71,340	67,056	68,213	70,597	73,826	72,067	68,483	68,589	73,011	74,299	860,831
2017	78,973	76,670	72,407	68,059	69,233	71,652	74,931	73,145	69,508	69,615	74,103	75,410	873,707
2018	80,673	78,321	73,966	69,525	70,724	73,195	76,544	74,720	71,005	71,114	75,699	77,034	892,522
Before-saving & After Rate-driven Impacts													
2013	63,473	61,622	58,196	62,618	63,060	64,924	68,714	67,261	63,238	64,426	69,519	72,395	779,448
2014	74,667	72,490	68,459	64,348	65,459	67,746	70,846	69,157	65,718	65,820	70,063	71,299	826,073
2015	76,157	73,937	69,825	65,632	66,765	69,098	72,259	70,537	67,030	67,133	71,461	72,722	842,557
2016	77,579	75,318	71,129	66,858	68,012	70,388	73,609	71,854	68,281	68,387	72,796	74,080	858,292
2017	78,740	76,444	72,193	67,858	69,029	71,441	74,710	72,929	69,303	69,410	73,885	75,188	871,129
2018	80,435	78,090	73,748	69,320	70,515	72,980	76,319	74,500	70,795	70,905	75,476	76,807	889,889
After-saving													
2013	63,396	61,470	57,973	62,310	62,687	64,480	68,192	66,652	62,543	63,638	68,635	71,415	773,391
2014	73,646	71,448	67,415	63,310	64,425	66,696	69,759	68,022	64,538	64,586	68,775	69,961	812,580
2015	74,774	72,536	68,431	64,257	65,403	67,723	70,846	69,069	65,511	65,554	69,821	71,026	824,951
2016	75,834	73,559	69,387	65,146	66,324	68,691	71,871	70,055	66,428	66,467	70,807	72,031	836,601
2017	76,638	74,332	70,107	65,814	67,020	69,427	72,652	70,805	67,120	67,153	71,554	72,792	845,413
2018	77,983	75,632	71,325	66,951	68,193	70,655	73,949	72,059	68,292	68,322	72,813	74,075	860,248

1.5 WHOLESALE

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	99,338	85,903	80,589	42,651	39,948	39,512	45,738	45,640	39,717	45,653	53,658	63,489	681,835
2014	63,882	55,242	51,825	43,040	40,313	39,872	46,155	46,056	40,079	46,070	54,147	64,068	590,750
2015	64,464	55,746	52,297	43,432	40,680	40,236	46,576	46,476	40,445	46,489	54,641	64,652	596,133
2016	65,053	56,255	52,775	43,829	41,052	40,603	47,001	46,901	40,814	46,914	55,140	65,242	601,579
2017	65,647	56,769	53,257	44,229	41,427	40,974	47,430	47,329	41,187	47,342	55,643	65,838	607,072
2018	66,246	57,287	53,743	44,633	41,805	41,348	47,863	47,761	41,563	47,775	56,151	66,439	612,614
Before-saving & After Rate-driven Impacts													
2013	99,183	85,769	80,463	42,547	39,851	39,415	45,626	45,528	39,620	45,542	53,527	63,333	680,403
2014	63,694	55,079	51,672	42,913	40,194	39,755	46,019	45,920	39,961	45,934	53,988	63,879	589,007
2015	64,274	55,581	52,143	43,304	40,560	40,117	46,438	46,339	40,325	46,352	54,480	64,461	594,375
2016	64,861	56,089	52,619	43,700	40,931	40,483	46,862	46,762	40,694	46,776	54,977	65,050	599,804
2017	65,453	56,601	53,100	44,099	41,304	40,853	47,290	47,189	41,065	47,203	55,479	65,644	605,281
2018	66,051	57,118	53,584	44,501	41,682	41,226	47,722	47,620	41,440	47,634	55,986	66,243	610,806
After-saving													
2013	99,125	85,654	80,295	42,371	39,637	39,161	45,327	45,181	39,223	45,091	53,021	62,773	676,859
2014	63,109	54,482	51,073	42,318	39,601	39,151	45,394	45,268	39,282	45,223	53,246	63,108	581,255
2015	63,476	54,773	51,338	42,510	39,774	39,323	45,622	45,491	39,448	45,440	53,531	63,481	584,208
2016	63,852	55,071	51,611	42,709	39,954	39,501	45,856	45,721	39,621	45,664	53,826	63,863	587,249
2017	64,236	55,377	51,891	42,914	40,140	39,685	46,097	45,957	39,799	45,894	54,127	64,254	590,372
2018	64,628	55,691	52,178	43,126	40,333	39,876	46,346	46,202	39,985	46,132	54,438	64,655	593,590

1.6 *INDUSTRIAL*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	28,177	27,665	27,287	31,440	29,561	28,129	28,346	28,512	28,166	31,759	33,164	32,772	354,977
2014	36,526	35,863	35,373	33,840	31,842	30,057	29,328	29,560	30,072	33,767	34,290	32,188	392,707
2015	36,629	35,964	35,472	33,935	31,932	30,142	29,411	29,643	30,156	33,862	34,387	32,278	393,809
2016	36,671	36,005	35,512	33,973	31,968	30,176	29,444	29,677	30,190	33,900	34,426	32,315	394,258
2017	36,661	35,995	35,503	33,964	31,959	30,168	29,436	29,669	30,182	33,891	34,416	32,306	394,151
2018	36,688	36,022	35,530	33,990	31,983	30,191	29,459	29,692	30,205	33,917	34,443	32,331	394,449
Before-saving & After Rate-driven Impacts													
2013	28,107	27,597	27,219	31,375	29,500	28,072	28,290	28,456	28,109	31,695	33,099	32,711	354,231
2014	36,419	35,757	35,268	33,740	31,748	29,969	29,242	29,473	29,983	33,667	34,189	32,093	391,549
2015	36,521	35,858	35,367	33,835	31,837	30,053	29,324	29,556	30,067	33,762	34,285	32,183	392,647
2016	36,562	35,898	35,408	33,873	31,874	30,087	29,357	29,590	30,101	33,800	34,324	32,220	393,095
2017	36,552	35,889	35,398	33,864	31,865	30,079	29,349	29,582	30,093	33,791	34,315	32,211	392,988
2018	36,580	35,916	35,425	33,890	31,889	30,102	29,372	29,604	30,116	33,817	34,341	32,235	393,285
After-saving													
2013	28,095	27,573	27,185	31,329	29,444	28,005	28,212	28,365	28,004	31,577	32,966	32,564	353,318
2014	36,264	35,599	35,109	33,581	31,589	29,806	29,074	29,297	29,799	33,474	33,987	31,882	389,461
2015	36,302	35,635	35,145	33,615	31,619	29,831	29,096	29,318	29,820	33,505	34,017	31,905	389,808
2016	36,276	35,608	35,119	33,589	31,593	29,803	29,066	29,287	29,789	33,476	33,987	31,872	389,465
2017	36,194	35,527	35,040	33,512	31,518	29,730	28,992	29,211	29,712	33,396	33,905	31,789	388,527
2018	36,147	35,480	34,994	33,467	31,473	29,684	28,945	29,163	29,662	33,347	33,855	31,736	387,951

1.7 *LIGHTING*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	1,244	1,108	1,137	1,103	1,135	1,121	1,139	1,105	1,160	1,161	1,169	1,029	13,610
2014	1,244	1,108	1,137	1,103	1,135	1,121	1,139	1,105	1,160	1,161	1,169	1,029	13,610
2015	1,244	1,108	1,137	1,103	1,135	1,121	1,139	1,105	1,160	1,161	1,169	1,029	13,610
2016	1,244	1,108	1,137	1,103	1,135	1,121	1,139	1,105	1,160	1,161	1,169	1,029	13,610
2017	1,244	1,108	1,137	1,103	1,135	1,121	1,139	1,105	1,160	1,161	1,169	1,029	13,610
2018	1,244	1,108	1,137	1,103	1,135	1,121	1,139	1,105	1,160	1,161	1,169	1,029	13,610
Before-saving & After Rate-driven Impacts													
2013	1,241	1,106	1,135	1,101	1,132	1,119	1,136	1,103	1,158	1,158	1,166	1,027	13,582
2014	1,240	1,105	1,134	1,100	1,131	1,118	1,135	1,102	1,157	1,157	1,165	1,026	13,570
2015	1,240	1,105	1,134	1,100	1,131	1,118	1,135	1,102	1,157	1,157	1,165	1,026	13,570
2016	1,240	1,105	1,134	1,100	1,131	1,118	1,135	1,102	1,157	1,157	1,165	1,026	13,570
2017	1,240	1,105	1,134	1,100	1,131	1,118	1,135	1,102	1,157	1,157	1,165	1,026	13,570
2018	1,240	1,105	1,134	1,100	1,131	1,118	1,135	1,102	1,157	1,157	1,165	1,026	13,570
After-saving													
2013	1,235	1,095	1,118	1,079	1,106	1,088	1,100	1,061	1,110	1,103	1,105	959	13,159
2014	1,171	1,037	1,067	1,036	1,069	1,056	1,073	1,038	1,092	1,091	1,098	958	12,788
2015	1,171	1,037	1,067	1,036	1,069	1,056	1,073	1,038	1,092	1,091	1,098	958	12,788
2016	1,171	1,037	1,067	1,036	1,069	1,056	1,073	1,038	1,092	1,091	1,098	958	12,788
2017	1,171	1,037	1,067	1,036	1,069	1,056	1,073	1,038	1,092	1,091	1,098	958	12,788
2018	1,171	1,037	1,067	1,036	1,069	1,056	1,073	1,038	1,092	1,091	1,098	958	12,788

1.8 *IRRIGATION*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Before-saving													
2013	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2014	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2015	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2016	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2017	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2018	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
Before-saving & After Rate-driven Impacts													
2013	585	592	503	963	3,122	5,382	7,795	9,724	7,290	4,324	1,839	580	42,700
2014	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2015	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2016	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2017	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
2018	586	593	504	965	3,128	5,393	7,812	9,745	7,306	4,333	1,843	582	42,790
After-saving													
2013	584	591	501	959	3,109	5,349	7,733	9,642	7,215	4,275	1,816	569	42,343
2014	578	586	495	948	3,084	5,300	7,661	9,566	7,159	4,246	1,804	565	41,992
2015	577	584	493	943	3,074	5,278	7,626	9,525	7,127	4,227	1,795	562	41,810
2016	575	582	491	939	3,063	5,256	7,591	9,485	7,094	4,208	1,787	558	41,628
2017	573	580	488	935	3,053	5,234	7,555	9,444	7,061	4,189	1,778	554	41,445
2018	571	578	486	931	3,043	5,212	7,520	9,404	7,028	4,169	1,770	551	41,263

2. WEATHER NORMALIZATION

Electricity consumption is impacted by weather, particularly by temperature. For example, energy requirements in an extremely cold winter month can be significantly higher than requirements in normal weather conditions in the same month, due to additional heating loads. As the load forecast is made under an assumption of normal weather, it is necessary to remove those extreme weather effects. This is the first step in forecasting.

Statistical tests were made to check whether the Residential, Wholesale, and Commercial loads were sensitive to temperature due to heating and cooling demands and whether the Irrigation load was sensitive to the precipitation. Industrial and Street Lighting loads are typically insensitive to the weather. Currently, only the Residential and Wholesale load classes are normalized because their associated regression results showed significant results with high R^2 values for these load classes while the R^2 values for the Commercial and Irrigation classes were low.

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

1. Calculate monthly Heating Degree Days (HDD)[4] and Cooling Degree Days (CDD)[5] for the Penticton weather station.
2. Calculate rolling 10-year HDD and CDD averages for each month of the year. These are used as the parameters of normal weather.
3. For the each of the Residential and Wholesale classes, regress energy on HDD or CDD on a seasonal basis. Four seasons were defined: winter is November to February, spring is March to May, fall is September to October, and summer is June to August. Thus all monthly energy and degree day data for each season are used and four separate regressions were calculated for each class. Princeton Event variables were included in the regressions to recognize that in 2007 Princeton Light and Power Inc. (PLP) ceased to exist as a wholesale customer and its customers became directly served by FortisBC.

   Chow tests confirmed that energy use consumption in the different seasons responded differently to HDD and CDD (regression coefficients were statistically different).
4. To normalize a month, e.g. February 2012:

   (a) obtain the month's HDD (or CDD) information from the Environment Canada;

   (b) calculate the deviation from the 10-year average (2002-2011) HDD (CDD) as found in Step 2;

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

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

(c) apply the regression slope obtained in Step 3 to this deviation to come up with a normalization adder;

(d) add the normalization adder to the month's load (residential or wholesale).

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

Normalized energy$_t$ = Energy$_t$ –HDD slope$_t$*(HDD$_t$ – Normal HDD$_t$) for t = 3-5, 9-10, 11-2,

Normalized energy$_t$ = Energy$_t$ –CDD slope$_t$*(CDD$_t$ – Normal CDD$_t$) for t = 6- 8

Regression slopes (MWh/degree day) and 10-year average degree days, taken over the 2003-2012 period for 2013 weather normalization, are found in the following table.

Table E2-1: Weather Normalization Coefficients and Normal Weather for 2013

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Residential HDD	172	172	111	111	111	-	-	-	84	84	172	
Residential CDD	-	-	-	-	-	132	132	132	-	-	-	
Wholesale HDD	90	90	60	60	60	-	-	-	30	30	90	90
Wholesale CDD	-	-	-	-	-	75	75	75	-	-	-	-
Normal HDD	577	483	398	275	137	44	5	8	84	270	448	579
Normal CDD	-	-	-	-	6	32	126	94	11	-	-	-

Table E2-1 illustrates that an additional HDD in February causes energy use to rise by 172 MWh for the residential sector, while an extra HDD in May causes consumption to rise by only 111 MWh.

The Company also investigated possible global warming effects through a long-term (30-year) trend analysis of HDD and CDD, but no statistically significant trend of increasing temperature was found for any month except for July as summarized below. Therefore, this load forecast does not explicitly address global warming effects. This is in line with the current utility practice according to recent surveys[6].

[6] Hydro One's survey of weather normalization practice in 2008, as reported in their Rate Application in May 2012http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20A/A-15-02.pdf (p.13, accessed on April 10, 2013.)

Table E2-2: Statistical Significance of Trend Analysis on HDD and CDD over 1983-2012

p-value	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
HDD	0.770	0.730	0.878	0.421	0.733				0.019	0.116	0.577	0.069
CDD						0.731	0.023	0.052				

3. ENERGY FORECAST

This section discusses methodologies to forecast energy requirements for different load classes for both before and after saving. Saving here is defined as the sum of DSM and other savings, including the Residential Conservation Rate (RCR), Customer Information Portal (CIP), Advanced Metering Infrastructure Project (AMI), and rate-driven impacts. Note that the RCR, the CIP, and AMI forecasts are only available for the residential class. DSM includes impacts up to 2012 but without incremental DSM savings from 2013 on. A general formula for an after-saving load in year *t* is

$$\text{After-saving Load}_t = \text{Before-saving Load}_t - \text{Saving}_t$$

The integration of City of Kelowna (CoK) load, which consists of the residential, commercial, and industrial classes, to the FBC direct service system on March 31, 2013 will create a decrease in the wholesale load and increases in the corresponding load classes in 2013. The integration impacts will be fully observed in 2014. To clearly present the load forecasting process, sections 3.1, 3.2, and 3.4 discuss the residential, commercial, and industrial loads with and without the CoK integration in this order. Details of CoK load forecast are given in section C.7. Section 8 gives details of the DSM and other savings.

3.1 RESIDENTIAL

The formula to forecast the expected before-saving residential load in year *t* is

$$\text{Before-saving Load}_t = \text{UPC}_t{*}\text{Average Customer Count}_t,$$

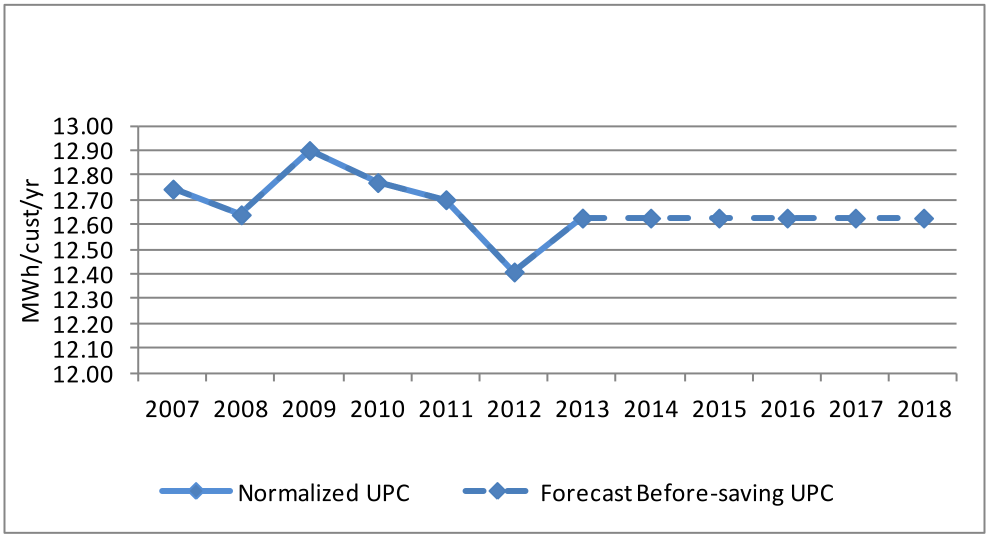
where UPC (use per customer, MWh per customer per year) is before-saving.

Statistical tests showed no clear trend for the before-saving UPCs (Figure E2-1.) Therefore, the before-saving UPC for 2014 was forecast at 12.63 (MWh per customer per year) as the average of historical normalized UPCs in the previous three years 2010-2012. This value was then assumed to remain constant throughout the period due to offsetting impacts of factors that increase load (e.g. there are more appliances to suit more comfortable lifestyle) and decrease load (e.g. appliances are more energy-efficient).

Table E2-3: Before-saving UPC without CoK

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
UPC	12.74	12.64	12.90	12.77	12.70	12.41	12.63	12.63	12.63	12.63	12.63	12.63

Figure E2-1: Before-saving UPC without CoK



Next, average customer count in year *t* is calculated as

$$\text{Average Customer Count}_t = 0.5*(\text{Year-end Count}_t + \text{Year-end Count}_{t-1})$$

The year-end customer count was based on the least square regression model below.

$$\text{Year-end Customer}_t = b_0 + b_1*\text{Population}_t + b_2*\text{Princeton Event}_t$$

where

- Population_t is the population data supplied by BC Stats that is customized to the Company's direct service area (excluding CoK)
- Princeton Event_t is a binary variable to adjust to the PLP integration into the FBC direct service system in 2007. It is not required when the data is from 2007 on.

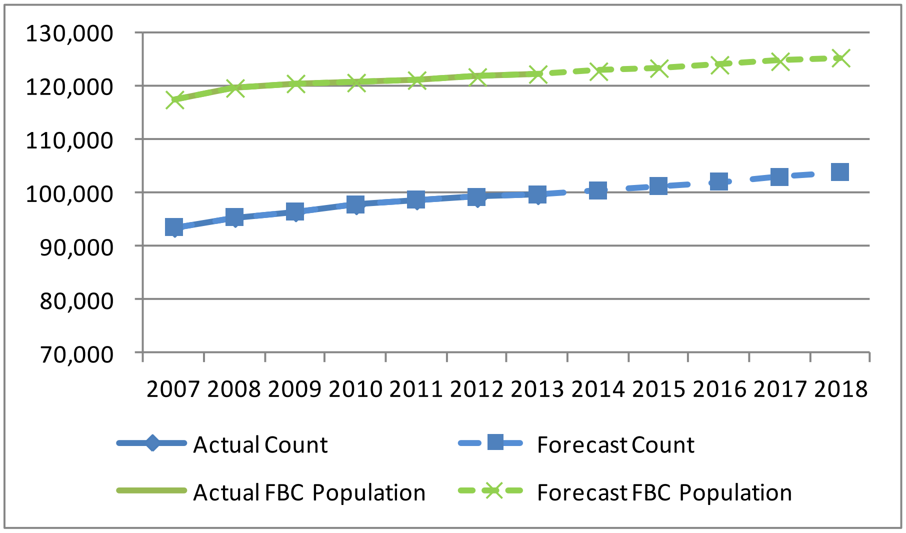
Table E2-4 displays regression results using the 2007-2012 data.

Table E2-4: Regression Results for the Residential Customer Count

Number of Data	6	p-value
Intercept b_0	(67,553)	0.047
Population b_1	1.37	0.002
Adjusted R-sq	0.90	
F statistic		0.000
Durbin-Watson	1.52	Passed

Figure E2-2 shows both the population series and the residential customer count.

Figure E2-2: Residential Customer Count vs. FBC Population without CoK



This is a methodological change from the 2012-2013 RRA, in which the year-end residential customer count was obtained indirectly via forecasting the additional customer count by a regression of the customer growth on the provincial housing starts supplied by the Conference Board of Canada (CBOC.) The FBC population series from BC Stats in the current format was not available by that time. There was a need to revise the method to forecast the residential customer count as the former method significantly overforecast in years 2011-2012 (by 662 and 2,092 customers respectively.) An opportunity for improvement occurred as the population series for the FBC direct service area (excluding CoK) was made available in early 2013 by BC Stats. Table E2-5 compares the performance of these two methods. Not only does the new method outperfom on the 2011-2012 counts, it also shows reasonably gradual recovering of the customer growth in the next few years from the current slow customer growth (only 433 in 2012).

Table E2-5: Comparisons of Forecasting Methods for the Residential Customer Count without CoK

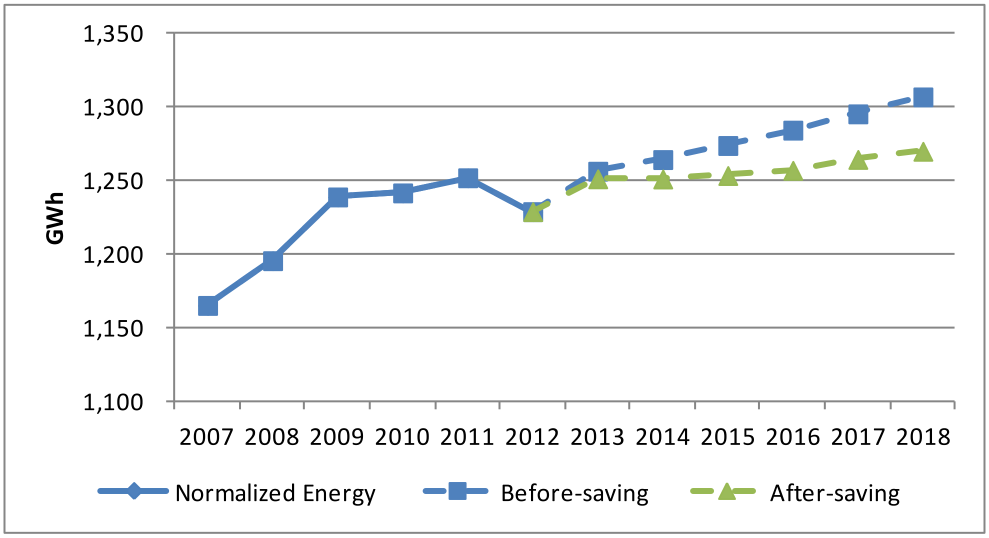
Year	Actual Year-end Customer Count	Regression on the Provincial Housing Starts	Regression on the FBC Population	Regression on the Provincial Housing Starts	Regression on the FBC Population
2007	93,647	91,389	93,233	(2,258)	(414)
2008	95,502	95,581	96,200	79	698
2009	96,565	96,410	97,356	(155)	791
2010	97,883	98,058	97,585	175	(298)
2011	98,795	99,309	98,216	514	(579)
2012	99,228	100,394	99,030	1,166	(198)
Mean Absolute Deviation (2011-2012)				840	389
Forecast				**Growth**	
2013		100,753	99,768	1,525	540
2014		102,331	100,487	1,579	719
2015		104,076	101,288	1,744	801
2016		105,906	102,142	1,830	854
2017		107,724	103,044	1,819	902
2018		109,550	103,966	1,826	921

Table E2-6 and Figure E2-3 show that the forecast before-saving and after-saving loads with slight increases.

Table E2-6: Residential Before and After-Saving Loads without CoK (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Normalized/ Before-saving	1,165	1,196	1,239	1,242	1,252	1,229	1,257	1,265	1,275	1,285	1,297	1,308
After-saving							1,251	1,251	1,254	1,257	1,264	1,270

Figure E2-3: Residential Before and After Saving Loads without CoK

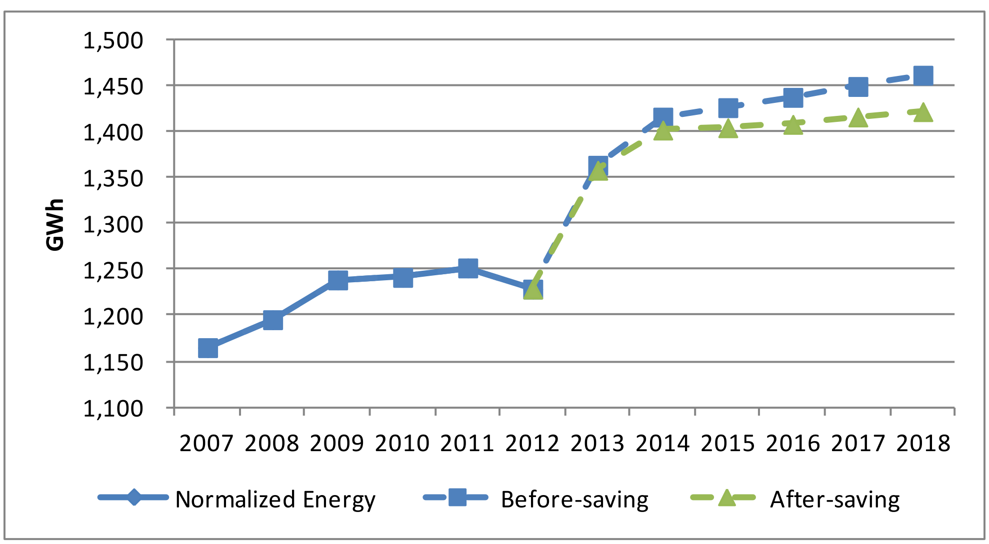


Finally, the integration of the CoK residential load gives the load forecast as follows.

Table E2-7: Residential Before and After-Saving Loads with CoK (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Normalized/ Before-saving	1,165	1,196	1,239	1,242	1,252	1,229	1,364	1,416	1,427	1,438	1,450	1,462
After-saving							1,359	1,402	1,405	1,409	1,417	1,422

Figure E2-4: Residential Before and After-Saving Loads with CoK



3.2 COMMERCIAL

The expected before-saving Commercial load in year *t* was forecast based on the provincial GDP supplied by the CBOC. The relationship was estimated from the following equation.

$$\text{Before-saving Load}_t = b_0 + b_1 * GDP_t + b_2 * \text{Princeton Event}_t$$

where

- Princeton Event_t is a binary variable for the PLP integration event in 2007
- Coefficients b_0, b1, and b_2 are obtained from an OLS regression analysis on the 2000 to 2012 data

Table E2-8: Commercial Load on GDP without CoK

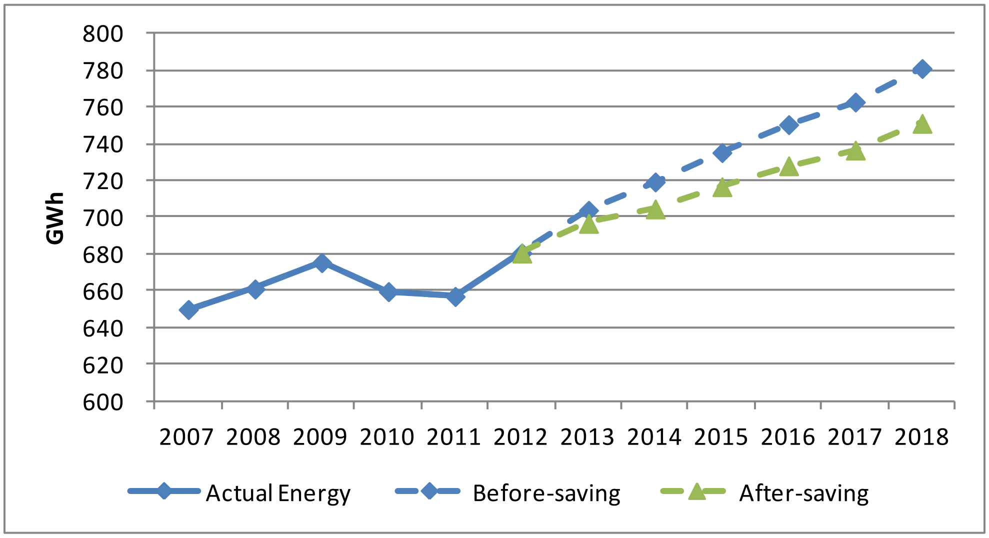
Number of Data	13	p-value
Intercept b_0	115,323	0.24
GDP b_1	3.57	0.00
Princeton Event b_2	-45,275	0.02
Adjusted R-sq	0.95	
F statistic		0.00
Durbin-Watson	1.80	Passed

Savings for this load class were from DSM and rate-driven impacts. Table E2-9 and Figure E2-5 display the before and after-saving loads.

Table E2-9: Commercial Before and After-Saving Loads without CoK (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Before-saving	650	661	675	660	657	681	704	719	735	751	763	781
After-saving							697	705	717	728	737	751

1 **Figure E2-5: Commercial Before and After Saving Loads without CoK**



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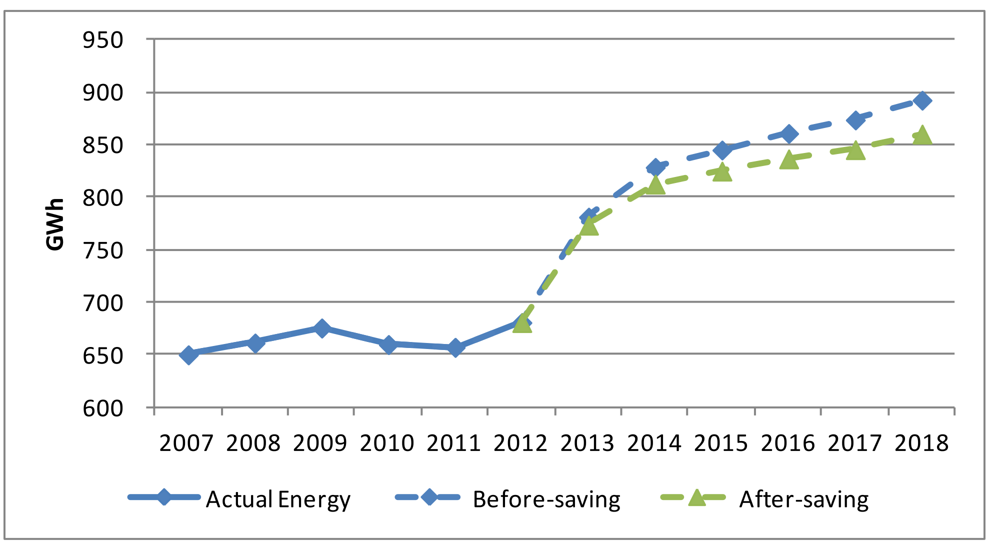
3 Finally, the integration of the CoK commercial load gives the load forecast as follows.

4 **Table E2-10: Commercial Before and After-Saving Loads with CoK (GWh)**

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Before-saving	650	661	675	660	657	681	781	829	845	861	874	893
After-saving							773	813	825	837	845	860

5 **Figure E2-6: Commercial Before and After Saving Loads with CoK**



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3.3 WHOLESALE

Prior to the filing of the 2012-2013 RRA in 2011, the Company forecast its wholesale load using the results of load surveys from all wholesale customers. The response rate was always 100 percent, and FBC then summed over the Wholesale customers' forecasts to come up with the before-saving wholesale load forecast. The main assumption in this approach is that in the near to medium-term, the Wholesale customers have the best knowledge of their service territory's load with respect to their customer mix, load behaviors, development projects with associated energy requirements, etc. For the 2012-2013 RRA, the Company was unable to use this approach because of the unavailability of the forecast for the City of Kelowna, which was a major component of the Wholesale forecast (accounting for around one third of the load.)

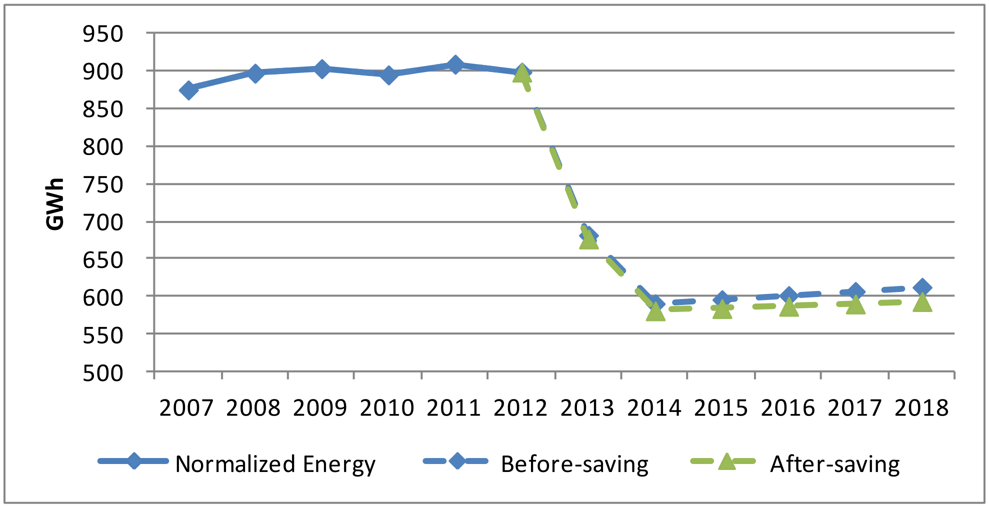
The integration of CoK into FBC direct service effective March 31, 2014 resolved this problem, and FBC resumed its past approach of seeking individual load forecasts for 2013-2018 from the Wholesale customers.

The table below summarizes the Wholesale customers' normalized load (including CoK load up to Q1 2013) and their before-saving load forecast for 2013-2018, as well as the whole class before and after-saving forecasts.

Table E2-11: Wholesale Load (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
BCH Lardeau	9	7	6	9	8	6	8	8	8	8	8	8
BCH Kingsgate	3	3	4	3	3	5	4	4	4	4	4	4
City of Grand Forks	41	41	41	41	41	41	41	41	42	42	42	43
City of Nelson	85	106	109	90	88	80	89	90	91	92	93	94
City of Penticton	347	342	345	341	344	341	346	349	352	355	358	362
District of Summerland	98	91	77	97	96	95	98	99	100	101	102	103
City of Kelowna	292	308	323	314	329	332	96	-	-	-	-	-
Before-saving	**875**	**898**	**904**	**895**	**910**	**899**	**682**	**591**	**596**	**602**	**607**	**613**
After-saving							**677**	**581**	**584**	**587**	**590**	**594**

Figure E2-7: Wholesale Load with CoK (GWh)



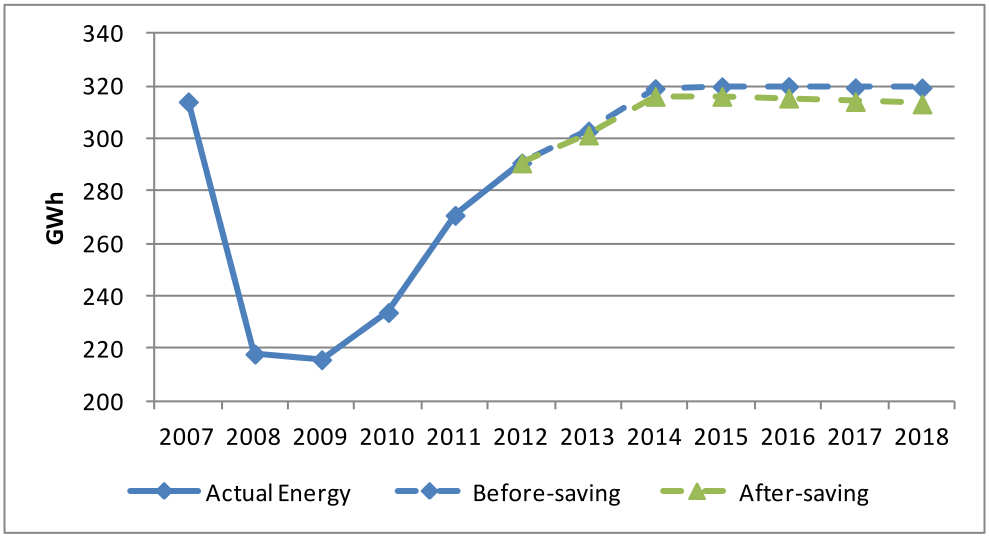
3.4 *INDUSTRIAL*

For the 2014-2018 period, the before-saving industrial load (excluding CoK) in year *t* is the sum of forecasts supplied by the current FBC 39 individual customers. These customers were counted at the beginning of 2013 and then assumed to stay in business for the entire forecasting period. For each customer, its self load forecast in each year was used if it responded to the load survey. Otherwise, its load was forecast by escalating its preceding year's load with the CBOC forecast GDP growth rates for the industrial sector that it is in. The majority of the FBC industrial customers responded to the surveys (72 percent of customers accounting for 79 percent of 2012 load.)

Table E2-12: Industrial Before and After-Saving Loads without CoK (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Before-saving	314	218	216	234	271	291	303	319	320	320	319	319
After-saving							301	316	316	315	314	313

Figure E2-8: Industrial Load without CoK (GWh)

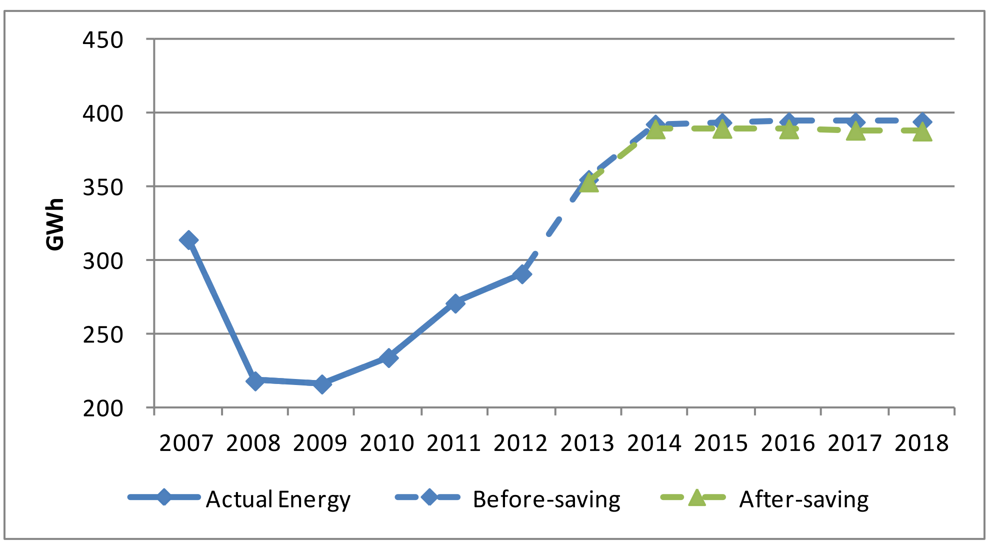


Loads with the CoK integration are as follows.

Table E2-13: Industrial Before and After-Saving Loads with CoK (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Before-saving	314	218	216	234	271	291	355	393	394	394	394	394
After-saving							353	389	390	389	389	388

Figure E2-9: Industrial Load with CoK (GWh)



3.5 *LIGHTING*

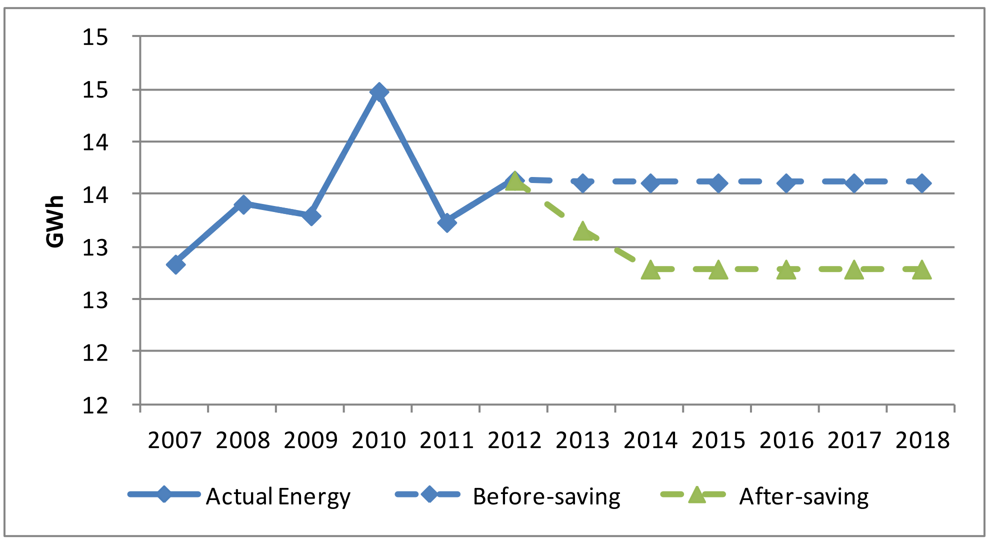
The before-saving street lighting forecast for 2014 was based on a 5-year trend analysis of lighting loads from 2008 to 2012. It was then assumed for all other years in the forecasting period.

Before and after-saving loads with the new method are given below.

Table E2-14: Street Lighting Before and After-Saving Loads (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Before-saving	13	13	13	14	13	14	14	14	14	14	14	14
After-saving							13	13	13	13	13	13

Figure E2-10: Street Lighting Load (GWh)



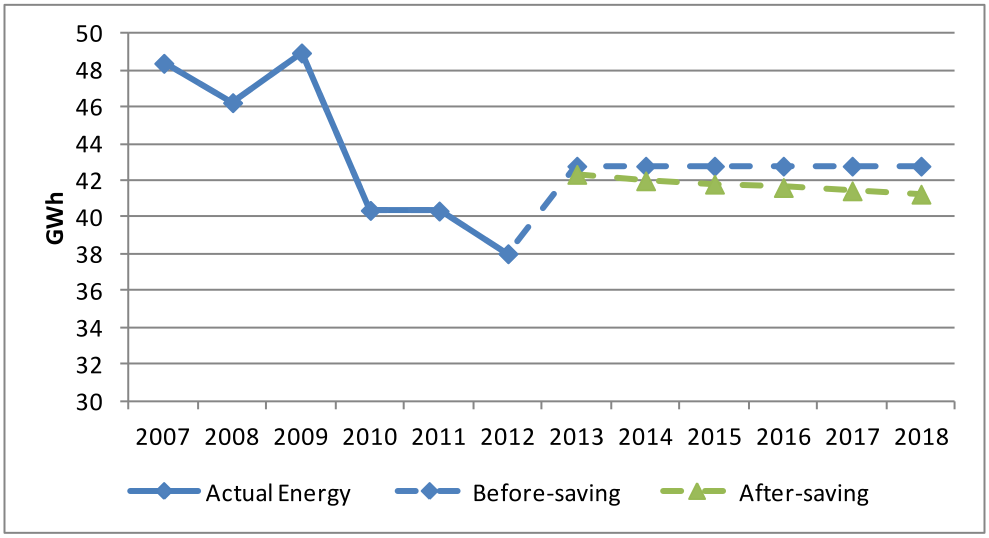
3.6 *IRRIGATION*

The before-saving irrigation load in 2014 was a simple 5-year average of actual loads in 2008-2012. It was then assumed for all other years in the forecasting period.

Table E2-15: Irrigation Before and After-Saving Loads (GWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Actual/Before-saving	48	46	49	40	40	38	43	43	43	43	43	43
After-saving							42	42	42	42	41	41

Figure E2-11: Irrigation Load (GWh)



3.7 COK LOAD FORECAST

CoK load consists of three main load classes namely residential, commercial, and industrial. Due to unavailability of CoK past load information (the Company only successfully obtained information of the past three years from a third-party service company), it was not possible to forecast individual load sectors and then sum them up to obtain the total load for CoK. Therefore, CoK load was forecast as a whole from which individual load classes were derived.

The Company expects to see CoK's before-saving load growth rate of around 0.5% in the near future. This load growth is close to CoK's 2012 actual load growth of 0.4% and when combined with CoK savings, produces an almost flat growth for CoK after-saving load (see Table C.8-1.) This is consistent with the Company's perspective of CoK load growth in the 2012 CoK Application that has been approved by the BCUC. If CoK remained as a FBC wholesale customer, this before-saving load growth rate would give a forecast that, when summed together with the Wholesale customers' forecasts, would give consistent results with the forecast produced by the previous regression method in the 2012-2013 RRA to forecast of the Wholesale load including CoK.

To allocate the net load to the load classes, the Company checked CoK load shares from 2010 to 2012. The historical load compositions turned out to be quite consistent, and the forecast mix is determined as 3-year averages of (45.4%, 32.6%, 22.0%) for the residential, commercial, and industrial loads respectively. CoK loads are summarized in the table below.

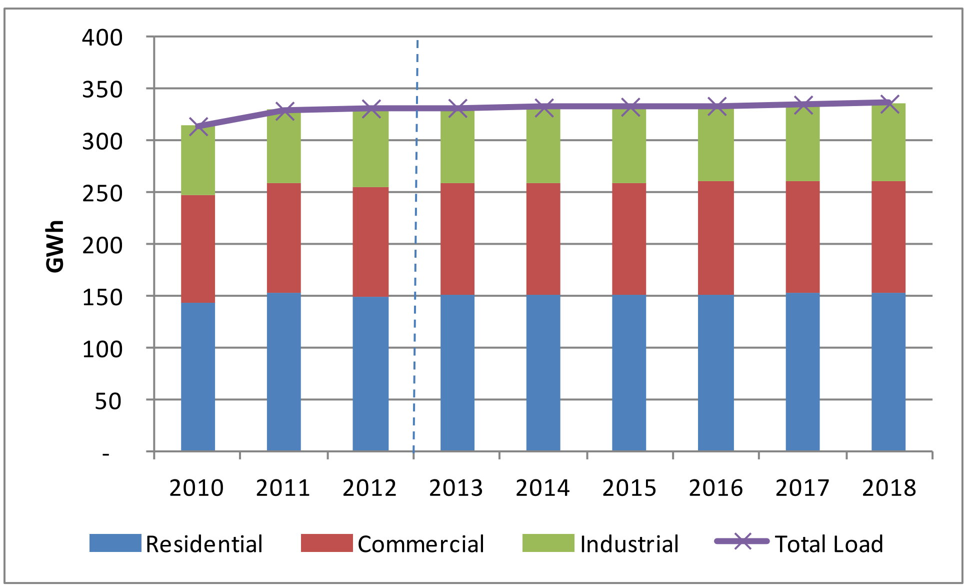
Savings for the COK include DSM and rate-driven impacts for all load classes and RCR, CIP and AMI for the residential class.

Table E2-16: CoK Energy (GWh)

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Normalized/ Before-saving	314	329	332	333	335	337	338	340	342
Residential	143	154	150	151	152	153	154	154	155
Commercial	105	105	106	109	109	110	110	111	111
Industrial	67	71	76	73	74	74	74	75	75
After-saving				332	332	333	334	335	336
Residential				151	151	151	152	152	152
Commercial				108	108	108	108	109	109
Industrial				73	73	74	74	74	75

Figure E2-12 displays CoK after-saving loads.

Figure E2-12: COK Load (GWh)



The CoK integration does not result in any change of the net load. It just reallocates CoK load from the wholesale sector to the residential, commercial, and industrial classes. As a result, there will be a decrease in the wholesale load in 2013, which is entirely offset by increases in the other three load classes. The full-year impacts are first observed in 2014.

3.8 DSM AND OTHER SAVINGS

Tables E2-17 and E2-18 display DSM by load class (excluding DSM already embedded in historical loads) for the current FBC system with the CoK integration and for the CoK itself respectively.

TableE2-17: DSM with CoK (GWh)

	2013	2014	2015	2016	2017	2018
Residential	5.8	13.0	17.2	21.3	25.4	29.4
Commercial	6.1	13.5	17.6	21.7	25.7	29.6
Wholesale	3.5	7.8	10.2	12.6	14.9	17.2
Industrial	0.9	2.1	2.8	3.6	4.5	5.3
Lighting	0.4	0.8	0.8	0.8	0.8	0.8
Irrigation	0.4	0.7	0.9	1.0	1.2	1.4
Net DSM	17.1	37.8	49.5	61.0	72.5	83.8

Table E2-18: DSM for CoK (GWh)

	2013	2014	2015	2016	2017	2018
Residential	0.3	0.8	1.0	1.2	1.5	1.7
Commercial	0.4	0.9	1.2	1.5	1.8	2.1
Industrial	0.0	0.1	0.1	0.1	0.1	0.2
Net DSM	0.8	1.8	2.3	2.9	3.4	4.0

Besides DSM programs administered by the PowerSense group, the Company also has other saving programs including Residential Conservation Rate (RCR), Customer Information Portal (CIP), Advanced Metering Infrastructure (AMI), and rate-driven. RCR, CIP, and AMI are currently forecast for the residential class only, including CoK load after the integration. RCR, CIP, and rate-driven impacts are calculated as percentage of the corresponding before-saving load. The rate-driven impact of 0.3 percent is the product of the assumed elasticity of -0.05 and the forecast average rate increase of 5.9 percent in 2014-2018. This saving is independent of the RCR saving and applied to all rate classes. In the absence of specific information with regards to price elasticity as presented in the RCR application, FBC has applied the assumption of -0.05[7] elasticity made by BC Hydro. BC Hydro is considered as the closest utility to FBC in terms of its public policies, geographical proximity, customer mix and behavior, and its assumed price elasticity of -0.05 has been well defended in a testimony for the BCH LTAP 2008[8]. In the

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7 BCH 2012 IRP, App. 2A, p. 14, http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix36.pdf, accessed as of April 12, 2013.

8 http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/info/pdf/2008_ltap_appendix_e.pdf, accessed as of April 12, 2013

future, results from a study on the RCR control group conforming to the Commission’s decision on the RCR Application will provide the Company with more information on its price elasticity.

Table E2-19 shows the RCR, CIP, and rate-driven impacts in percentage of the before-saving load. Table E2-20 displays the values for the whole FBC system after the CoK integration and for the CoK.

Table E2-19: RCR, CIP and Rate-Driven Impacts as Cumulative Percentage of Before-saving Load

	2013	2014	2015	2016	2017	2018
RCR	-	0.22%	0.60%	0.98%	1.36%	1.74%
CIP	-	-	0.15%	0.30%	0.30%	0.30%
Rate-driven	0.2%	0.3%	0.3%	0.3%	0.3%	0.3%

Table E2-20: RCR, CIP and Rate-Driven Impacts with CoK (GWh)

	2013	2014	2015	2016	2017	2018
RCR	0.0	3.1	8.6	14.1	19.7	25.5
CIP	0.0	0.0	2.1	4.3	4.3	4.4
Rate-driven	6.8	9.7	9.8	9.9	10.0	10.1

Table E2-21: RCR, CIP and Rate-Driven Impacts for CoK (GWh)

	2013	2014	2015	2016	2017	2018
RCR	0.0	0.3	0.9	1.5	2.1	2.7
CIP	0.0	0.0	0.2	0.5	0.5	0.5
Rate-driven	0.3	0.4	0.5	0.5	0.5	0.5

AMI impacts, as taken from the Company’s AMI Application in July 2012, include two components with their offsetting impacts on the gross load:

- sales recovered from illegal grow-op sites, considered here as AMI savings with negative values, and
- loss reduction due to closing illegal grow-op sites, not considered here as savings but covered under losses with positive values.

Table E2-22: Sale Recovered by AMI (GWh)

	2013	2014	2015	2016	2017	2018
With CoK	3.2	6.3	10.2	14.6	20.5	23.9
COK	0.4	0.7	1.1	1.6	2.3	2.7

4. PEAK DEMAND FORECAST

Historical monthly peak load data for ten years (2003-2012) were escalated by historical gross load growth rates and then averaged to obtain monthly peaks under normal weather condition. Zellstoff Celgar load was excluded from the historical data since it was forecast separately. Seasonal peaks were used for both the winter and the summer. The twelve monthly peaks, as well as the seasonal peaks, were then escalated by the annual load growth rates in the forecast period to produce forecast monthly peaks. Zellstoff Celgar's expected monthly peak of 16 MW was finally added to these values to obtain the before-saving peak forecast. The winter peak and the summer peak are usually assumed to replace monthly peaks in December and July respectively.

The after DSM peak forecast was found by subtracting DSM capacity saving forecast, which is supplied by the DSM group, from the before DSM peak forecast for each month in each year.

Table E2-23: Before-saving Expected Peak Forecast (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
2013	694	621	569	499	453	493	571	558	463	529	638	691	748	581
2014	704	630	577	506	459	499	579	565	469	536	647	700	757	590
2015	711	636	583	511	464	504	585	571	474	542	653	707	764	595
2016	718	642	588	516	468	509	591	576	478	547	659	714	771	601
2017	724	648	594	520	472	514	596	582	483	552	665	720	779	606
2018	732	655	600	526	477	519	602	588	488	557	672	728	786	613

Table E2-24: After-saving Expected Peak Forecast (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Winter	Summer
2013	694	620	568	497	451	490	569	554	459	525	633	686	743	579
2014	699	625	572	500	454	494	574	559	463	530	640	694	750	584
2015	704	629	576	504	457	497	578	563	466	534	645	699	756	588
2016	709	633	580	507	460	500	582	567	468	537	649	704	761	592
2017	714	637	584	510	462	503	585	570	471	540	653	709	767	595
2018	720	642	588	513	466	507	590	574	474	544	659	715	772	600

5. CONCORDANCE WITH THE LOAD FORECAST TECHNICAL COMMITTEE'S RECOMMENDATIONS

The Company has taken necessary steps in order to conform to the recommendations to improve future load forecasts set by the Load Forecast Committee (LFC) in November 2011. Summaries are given below (the section numbers in parentheses refer to the sections in the LFC Technical Report dated November 25, 2011.)

1. To review its current methodologies for each customer class (Sections 11 – 16)

FBC Action: Necessary steps taken.

The Company checked the existing forecasting method with updated parameters for each load class and proposed appropriate changes to the residential customer count, the wholesale load, and the lighting load classes. Please refer to Recommendation 8 for further detail.

2. To review its methodology related to the inclusion of the DSM forecast (Section 3)

FBC Action: Necessary steps taken.

The Company has decided to keep using the implicit DSM integration method in the 2012-2013 RRA. This method forecasts before-DSM load with DSM embedded into loads and only considers impacts of new DSM programs that have not been embedded in the load. This is different from the explicit integration method, which removes all DSM impacts in the historical load, forecasts the before-DSM load totally free from DSM, then subtracting DSM impacts from both historical and new programs.

The Company has kept this implicit method for two reasons:

- This is the most commonly practiced method in the power industry (used by around 75% utilities according to the latest surveys[9]);
- The Company does not have historical cumulative DSM numbers broken down into load classes on a monthly basis. This is a necessary DSM format for the explicit method if weather normalization is on a monthly (or seasonal) basis.

3. To obtain and test sub-provincial data inputs for forecasting (Section 6)

FBC Action: Necessary steps taken.

9 Hydro One survey as reported in the testimony of Ahmad Faruqui, an energy expert on DSM integration methods in March 2013 (see Schedule 1, p.16) http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-Rate-Case-2013/Vol-1-7-of-11-Faruqui-Economic-Energy-Eff-Impacts-Sales-Forecasts-Rebuttal.pdf

The Company has facilitated BC Stats with geographical information in its production of the population series for the FBC direct service area (excluding CoK.) This new series has enabled FBC to change for a better method to forecast the residential customer count.

The Company could not obtain the GDP forecast customized for its direct service area as the CBOC had already informed the Company that due to limited resources, it would only consider a request for this series if BC Hydro continued its service with the CBOC. Unfortunately, BC Hydro has ceased this service with the CBOC. Nevertheless, forecasting with the provincial GDP data by the CBOC in the past has been giving good results, and it seemed unnecessary for the Company to seek a customized GDP series for the moment.

4. *To investigate whether it is possible and appropriate to recognize long-term climate change in its load forecast*

FBC Action: Necessary steps taken.

Investigations on the data specific to the FBC service area did not give statistically significant results to proceed with necessary procedures to explicitly address long-term climate changes in the load forecast. Section 2 gives more detail on this subject. Note also that this forecast is for the short term 2014-2018.

5. *To review the Company's treatment of price elasticities in its load forecast, including a comparison of the price elasticity used by FortisBC's natural gas affiliate.*

FBC Action: Necessary steps taken.

Please refer to section 3.8 for more details. For the moment, price elasticity is not used explicitly as a direct input in gas forecasting. After numerous reviews on this topic, it was concluded that short run residential price elasticity has a no material impact on the gas demand. This finding is consistent with the American Gas Association ("AGA") estimated price elasticity study[10].

6. *To work with Wholesale customers to obtain individual load forecasts for review in the preparation of FortisBC's Wholesale forecast*

FBC Action: Necessary steps taken.

Please refer to section 3.3 for more details.

7. *To target customer-supplied forecasts for at least two-thirds of the Industrial surveyed load*

FBC Action: Necessary steps taken.

Please refer to section 3.4 for more details.

[10] Response to BCUC 2.4.1 for 2012-2013 RRA.

8. To provide greater detail around the validation of the load forecast methodologies. This will include tests that demonstrate the proposed load forecast methodology for each rate class is validated and reasonable against alternative methods. For any methodology changes from previous filings, there will be accurate side-by-side comparisons of the previous versus new methodology and a detailed explanation to support the new methodology presented

FBC Action: Necessary steps taken.

The Company proposed methodological changes regarding the forecast of:

- The residential year-end customer count: A direct forecasting customer count using regression on the population for the FBC direct service, which is supplied by the BC Stats, replaced the previous forecasting customer count growth using the provincial housing starts supplied by the CBOC. The motivation was the overforecasting issues with the customer count growth method. Validation on historical loads in 2011-2012 showed better a performance of the new method. For further information, refer to the discussion in section 3.1, particularly Table E2-5.
- The wholesale load class: The use of the wholesale customers' load forecasts was resumed upon the CoK integration (section 3.3.) The table below shows consistency between the wholesale load forecast, including COK, by the previous regression on the provincial GDP and the sum of the current wholesale load (from the load surveys) and COK load (at the before-saving growth rate of 0.5 percent.)

Table E2-25: Comparison of the Wholesale Load Forecast Methods (GWh)

	2013	2014	2015	2016	2017	2018
Previous Regression	917	924	931	938	944	952
Proposed Sum	919	926	933	940	947	954

9. To pursue opportunities for collaboration and coordination with FortisBC Energy Inc. regarding the provision of Demand Side Management initiatives and load forecasting activities, which could benefit ratepayers.

FBC Action: Necessary steps taken.

Both electric and gas load forecasting are now administered from a single load forecasting group. The forecast analysts are sharing methodologies and data where possible. In addition we are currently investigating the benefits of combining all the modelling functions into a single expanded version of the "Forecasting Information System" (FIS). FIS has been in use for gas forecasting for more than a decade and is widely accepted by the BCUC. The analysis will determine the pros, cons and costs of incorporating the electric forecast model into FIS. If successful this is expected to lead to increased staff efficiencies and more consistent methodologies.

Appendix E3

PROBABILITY FORECASTING SYSTEM PLANNING

1. LOAD FORECASTING – USE OF "1 IN 20" VS "1 IN 10" YEAR LOAD FORECASTS

FBC prepares load forecasts for two reasons: one (a "top-down" forecast) for Resource Planning purposes, and another (a "bottom-up" forecast) for System Planning purposes.

The Resource Planning system load forecast is used to ensure that FBC has sufficient energy and capacity resources (which may be from either physical generation or contracted power purchases) to meet the system demand for all hours of the year. This forecast is based on weather-normalized, historical total system load values. For this reason, it is considered to be a "top-down" forecast. It considers only the aggregate customer load and makes no attempt to regionalize or allocate energy usage within the service area. This is because for Resource Planning purposes the specific location of the source of production or the point of consumption is not relevant. This forecast is considered to represent the "expected" or "most-likely" prediction of energy and capacity for the period that it covers, also known as a "1 in 2" or 50% probability forecast. In other words, half the time the actual load will be higher than forecast. As it is weather-normalized, the forecast does not make specific allowances for weather extremes or unforeseen load growth. The forecast is used in Resource Planning studies to determine if there will be sufficient resources available in the future or if FBC needs to obtain additional energy or capacity resources – either through the construction of new generation or through new power purchase agreements. This forecast is not otherwise used for FBC infrastructure planning purposes.

In contrast to this, the System Planning group also develops forecasts of the expected peak demand for FBC's distribution feeders and substations. This forecast is based on historical actual loads and is used for planning sustaining and growth capital projects. The methodology uses the highest peak of the last five years of load data to drive an extrapolation of future peak loads. Area forecasts are derived by summing the forecast loads on individual distribution feeders and then applying appropriate load-diversity reduction factors (which represent the fact that all feeders do not typically peak at exactly the same time). Since this forecast is determined using individual feeder loadings instead of the total system load, it is considered a "bottom-up" forecast. Further, unlike the Resource Planning forecast described above, the System Planning forecast inherently takes into account load extremes (typically due to temperature extremes) as it is based on historical peak readings. Indeed, it is essential that this forecast considers extreme loading conditions to ensure that FortisBC has sufficient transmission and distribution capacity to meet the instantaneous customer demand for all hours of the year. The forecast is used in steady-state and contingency planning studies to determine if there is a need to increase the transmission, substation or distribution system capacity by constructing additional infrastructure. FBC has not assigned a specific probability or accuracy to this forecast but notes that it is based on only the most recent five years of historical load data.

During the preparation of the 2012 Integrated System Plan, the Resource Planning and System Planning groups met to consider a method to reconcile the two forecasts for validation purposes. To that end, the Resource Planning group developed an additional “1 in 20” (95 percent probability) system load forecast. In this case, the actual load would be equal or less than the forecast in 19 of 20 years. It was felt that this forecast best represented potential load excursions due to weather extremes. Further, when the two groups compared the two forecasts (the Resource Planning “1 in 20” forecast and the totalized System Planning coincident peak forecast) that there was reasonable agreement between the two. This provided reasonable certainty that the underlying forecasting methodologies were sound. The use of the “1 in 20” forecast was also discussed in the response to BCUC IR 2.3.1 (Losses) attached (FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan).

Beyond this validation, the 1 in 20 forecast has not been directly used in determining the timing of the capital projects over the PBR Period. The timing for these projects has been determined using the System Planning distribution load forecast – which is not a “1 in 20” forecast. Instead, as noted above, it is based on historical peak loads within the last five years. While there is inherent uncertainty in any forecast, FBC considers this methodology to be the most appropriate method for determining the timing of the proposed capital projects. For this reason, the choice of a “1 in 20” or “1 in 10” forecast has no effect on the timing of the project projects.

Although the forecasts do not determine the timing of capital projects, a comparison of the 1-in-20 and 1-in-10 forecasts is provided below.

	1-in-20		1-in-10	
	SUMMER PEAK (MW)	WINTER PEAK (MW)	SUMMER PEAK (MW)	WINTER PEAK (MW)
2013	684	908	658	853
2014	694	922	667	861
2015	701	931	673	869
2016	707	939	679	875
2017	713	947	685	884
2018	719	957	691	892
2019	726	964	697	897
2020	730	971	701	904
2021	736	978	707	911
2022	741	985	712	917
2023	746	992	717	924
2024	751	1000	721	931
2025	757	1007	727	937
2026	762	1014	732	944
2027	767	1021	737	950
2028	772	1028	742	957
2029	778	1035	747	963
2030	783	1042	752	970
2031	788	1049	757	976
2032	793	1056	762	983
2033	798	1063	766	990

1-in-10 vs. 1-in-20	
SUMMER PEAK (MW)	WINTER PEAK (MW)
-26	-55
-27	-61
-28	-62
-28	-64
-28	-63
-28	-65
-29	-67
-29	-67
-29	-67
-29	-68
-29	-68
-30	-69
-30	-70
-30	-70
-30	-71
-30	-71
-31	-72
-31	-72
-31	-73
-31	-73
-32	-73

3.0 Reference: System Planning Forecasts
Exhibit B-7, BCUC 1.6.2, Table BCUC IR1.6.2; BCUC 1.229.2
1-in-20 Peak Forecast

3.1 As the industry practice appears to more consistently use a 1-in-10 risk level, please provide Table BCUC IR1.6.2 showing the summer and winter "1-in-10" peak load forecasts, and provide the comparison with the "1-in-20" results.

Response:

FortisBC offers the following clarifications with respect to the 1-in-20 peak forecast:

1. The forecast is not used for resource planning (i.e. for power purchases);
2. The forecast is not used directly for system capital planning.
3. The forecast is used only for benchmarking the existing distribution planning forecast. The distribution planning forecast does not inherently contain a quantifiable risk index (as it is constructed from the "bottom up" using historical, individual feeder load data). By comparing the 1-in-20 forecast to the distribution planning forecast, FortisBC is then able to confirm that the distribution planning forecast (and hence system infrastructure) can accommodate potential load increases due to reasonably extreme weather variations.
4. All capital projects were driven solely by the distribution planning forecast; no project timing changes resulted from the use of the 1-in-20 forecast.

Notwithstanding the above, FortisBC also does not agree that industry practice is standardizing around a specific risk index for system planning purposes. There are currently no standards, mandatory or other, that prescribe the risk level and confidence bands of a load forecast. Local conditions in the economy and weather vary significantly in different jurisdictions, making the application of uniform risk standards impractical. For example, a 95% confidence band will be wider in jurisdiction A vs. B, if weather patterns in A are more variable than in B. Several utilities (Bonneville Power, PacifiCorp, ISO New England and others) compute confidence bands for 90% and 95% confidence (1-in-10 and 1-in-20 risk levels). BC Hydro employs Monte Carlo methods to compute a 90% confidence band, indicating there is a 10% probability that the actual peak load will exceed the forecast peak load in a particular year. Similarly, the PJM interconnection employs a 90% confidence level. A large geographic jurisdiction, such as PJM, Bonneville, ISONE, will generally have a lesser variance due to extreme weather, as non-uniform weather conditions will mitigate the total effect. Smaller areas, such as FortisBC, are exposed to a greater relative weather risk. The objective of the 1-in-20 load forecast at FortisBC is to provide system planners with a benchmark level that quantifies the risk of the transmission plan. Transmission adequacy is extremely important, as shortages in transmission cannot be mitigated in the short term except with customer outages.

Appendix F1

AMENDED AND RESTATED MUTUAL SHARED SERVICES AGREEMENT

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 COST ALLOCATION MODEL (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:

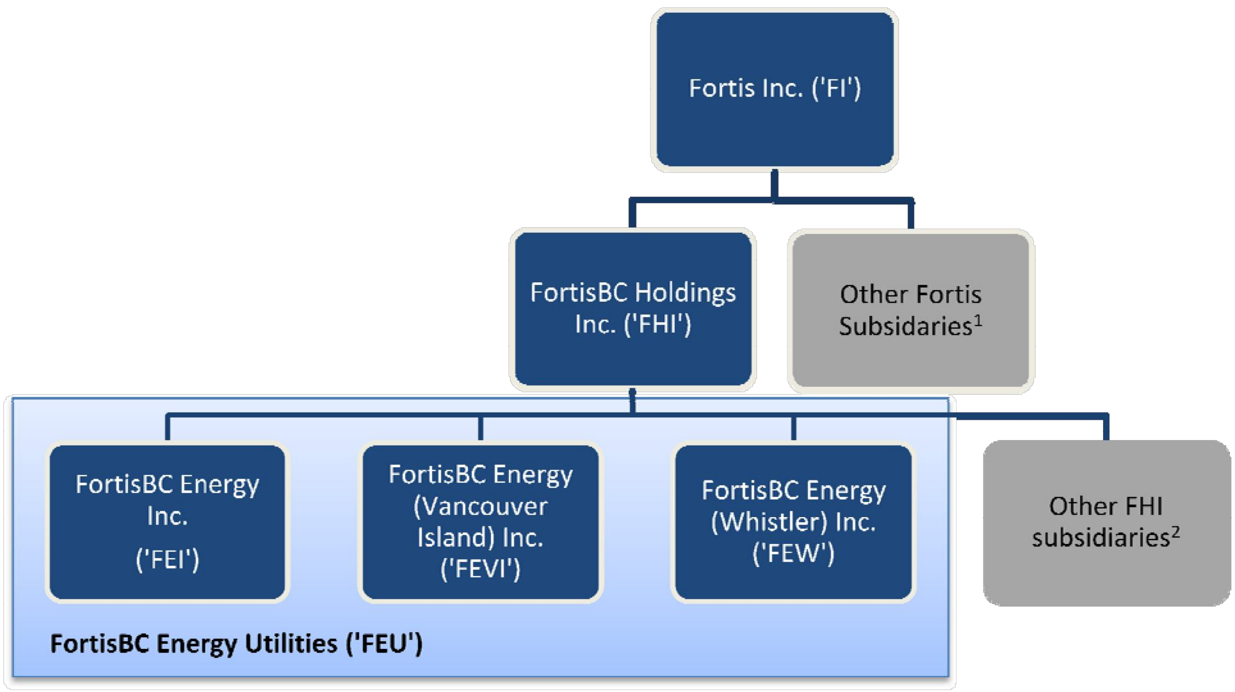
- **Section 1: Executive Summary** - Includes a brief discussion of KPMG's review approach and summary of findings.
- **Section 2: Purpose of Report** - Outlines the structure of the report and provides a brief explanation of each section.
- **Section 3: Background** - Provides background on the structure 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:
    - o Compared the cost allocator(s) to historic cost allocators;
    - o 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;
    - o 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;
    - o 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
    - o 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:
    - o Reconciled cost pools details to FI and FHI's 2013 budget figures from its 2012-2013 RRA.
    - o For a sample of individuals in each cost pools, agree their roles to job descriptions or employee organizational charts;
    - o Validated the mathematical accuracy of cost allocations and ensured that the allocators are consistent with the allocators noted in Phase 3; and
    - o 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>
</table>
</td></tr>
</table>

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.

Appendix F3

OVERHEAD CAPITALIZATION METHODOLOGY REVIEW (KPMG)

KPMG

FortisBC Inc.

Overhead Capitalization Methodology Review

June 28, 2013

Table of Contents

1. Executive Summary

KPMG was retained by FortisBC Inc. ("FBC" or "the Company") to assist with their overhead capitalization study (the "Study"). The purpose of the Study is to review a) the overhead capitalization methodology and resulting overhead capitalization rate and b) the direct overhead loading methodology and the resulting capitalized costs. This study was conducted 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 FBC as the percentage of Operations and Maintenance ("O&M") costs, related to capital activity, which have not been directly charged to capital. "Direct overhead loading costs" are defined as project specific Transmission and Distribution ("T&D") capital costs which have not been directly charged to specific projects, but have been allocated using an alternate methodology.

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 FBC 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 Electric 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.*

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' regulators. 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.

KPMG's findings on the overhead capitalization rate and direct overhead loading are as follows:

Overhead capitalization rate:

In order to provide an objective and reasonable basis of determining overhead capitalization rate, FBC undertook a capital cost allocation study. Two methodologies were used for the examination of the overhead capitalization rate – a Survey-based Model and a Mathematical Model. The Study utilized the BCUC approved 2013 FBC O&M budget (the "2013 Budget") figures pursuant to BCUC order G-110-12. The O&M costs which are allocated to capital through the overhead capitalization rate are net of direct overhead loading costs.

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.

KPMG finds the FBC Survey-based capital cost allocation methodology, as detailed in Section 7 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). These methodologies are 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 FBC, 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 O&M cost, is estimated to be approximately **15 percent**.

In the absence of future significant regulatory, accounting and organizational changes, the application of this overhead capitalization rate in future periods may continue to be appropriate.

Direct overhead loading:

This study examined FBC's direct overhead loading methodology, which captures project specific T&D capital costs that have not been directly charged to capital projects, due to the administrative burden required to do so.

KPMG finds the FBC direct overhead loading methodology, as detailed in Sections 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities, as examined in the evaluation criteria discussed below. These methodologies are consistent with FBC's internally generated evaluation criteria and available accounting guidance.

Based on the results of the direct overhead loading methodology, a total 2013 Budget of **$4.7 million** of capital costs have been estimated and approved.

In the absence of future significant regulatory, accounting and organizational changes, the application of this direct overhead loading methodology in future periods may continue to be appropriate.

2. Purpose of Report

2.1 Project Scope

FBC has been asked by the BCUC to undertake a study related to the capitalization of overhead. This has been requested in Directive No. 21, page 152 of BCUC Order G-110-12 issued as a result of the FBC 2012-2013 Revenue Requirements Application. The Directive in Order G-110-12 with respect to capitalized overhead was as follows:

"For the next revenue requirements application, FortisBC is directed to provide an external audit opinion on the appropriateness of its capitalized overhead methodology. Further, if International Financial Reporting Standards (IFRS) is pursued in the next application, the Company is directed to perform a new study based on the accounting policy adopted at that time."

In addition, Directive No. 23 of Order G-110-12 has requested the following with respect to "direct overhead loading".

"Recognizing there is a need for more granular information and a closer examination of the current methodology, the Commission Panel approves the application of direct overhead as proposed by FortisBC for the current test period only. The Commission Panel directs FortisBC to ensure the direct overhead loading methodology is commented upon as part of the external audit opinion which is directed in Section 5.2.2.5 (i) Capitalized Overhead. In addition, the Commission Panel directs FortisBC in the next RRA to provide a more fulsome explanation as to the appropriateness of the direct overhead loading methodology and to include a full reconciliation and justification."

This report has examined the appropriateness of the capitalization of overhead costs which have not been directly charged to capital in response to Directive No. 21 and the appropriateness of the direct overhead loading methodology in response to Directive No. 23 as noted above. Within the context of the study, it is important to note that capitalized overhead should be distinguished from both costs which are charged directly to capital and from direct overhead loading.

- "Direct charges" are capital related 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.
- "Direct overhead loading" is defined as project specific T&D capital costs which have not been directly charged to specific projects but have been allocated using an alternate methodology.

Both direct charges and direct overhead loading are removed from O&M costs which, when multiplied by the capitalization rate determined under either the Mathematical and Survey-based Models, determine the amount of capitalized overhead.

"Capitalized overhead" therefore reflects those costs that relate to capital projects but that have not been specifically identified with or charged directly to any individual capital project, either through direct charges or through the direct overhead loading process.

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 FBC has 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 FBC 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 FBC under the U.S. GAAP financial reporting framework. In addition, following Directive 23, this study will also examine the direct overhead loading methodology applied by FBC.

The basis of this 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 FBC;
- Reviews the capital overhead cost allocation methodology applied by FBC;
- Assesses the direct overhead loading methodology applied by FBC;
- Assesses the reasonableness of the activities allocated to capital under the direct overhead loading and capitalized overhead methodologies;
- Assesses the reasonableness of the cost drivers and allocation basis under these models; and
- Presents the resulting direct overhead loading cost and the overhead capitalization rates.

2.3 Scope Limitations

This section provides details of the limitations of this Study. These are as follows:

Management responsibility:

FBC's capitalization methodology 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.

KPMG engagement:

Our engagement is to comment on the reasonableness of the direct overhead loading and capital overhead cost allocation methodology, in the context of FBC'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 direct overhead loading or the capital overhead cost allocation methodology, associated costs or the resulting capitalization amount or 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 FBC's Study. However we have outlined the steps undertaken to assess the accuracy of the underlying data in Sections 5 and 8.6.

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 FBC management, the Audit and Risk Committee, and Board of Directors. It is understood that this report will be distributed by FBC 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 available regulatory guidance including BCUC's

Uniform System of Accounts Prescribed for Electric Utilities and FERC's *Uniform System of Accounts.*

- **Section 5**: **KPMG Approach** - Provides an explanation of KPMG's approach to assessing FBC's capital cost allocation methodology including the criteria used by KPMG during our analysis. This scope of the evaluation was agreed between KPMG and FBC 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: FBC Direct Overhead Loading Methodology and Results** - Provides a high level summary of the components of the direct overhead loading methodology and results.
- **Section 7: FBC Overhead Capitalization Methodology and Results** - Provides a high level summary of the components of the overhead capitalization methodology and results.
- **Section 8: KPMG Evaluation** - Provides KPMG's findings as to the reasonableness of the overhead capitalization and direct overhead loading 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.

FBC 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

In its 2006 Revenue Requirements Application, the Company submitted a new overhead capitalization methodology based on the principles of activity based costing to calculate the amount of overhead to be capitalized. The Company reached a Negotiated Settlement Agreement that was approved by the Commission in Order G-58-06. This Order approved the capitalization rate for 2006 and the Performance Based Regulation (PBR) term (2007 – 2009 inclusive) and agreed to review the methodology at the conclusion of the PBR term. The PBR term was extended in 2008 for the years 2009–2011 inclusive. An overhead capitalization rate of **20 percent** was agreed for the PBR term.

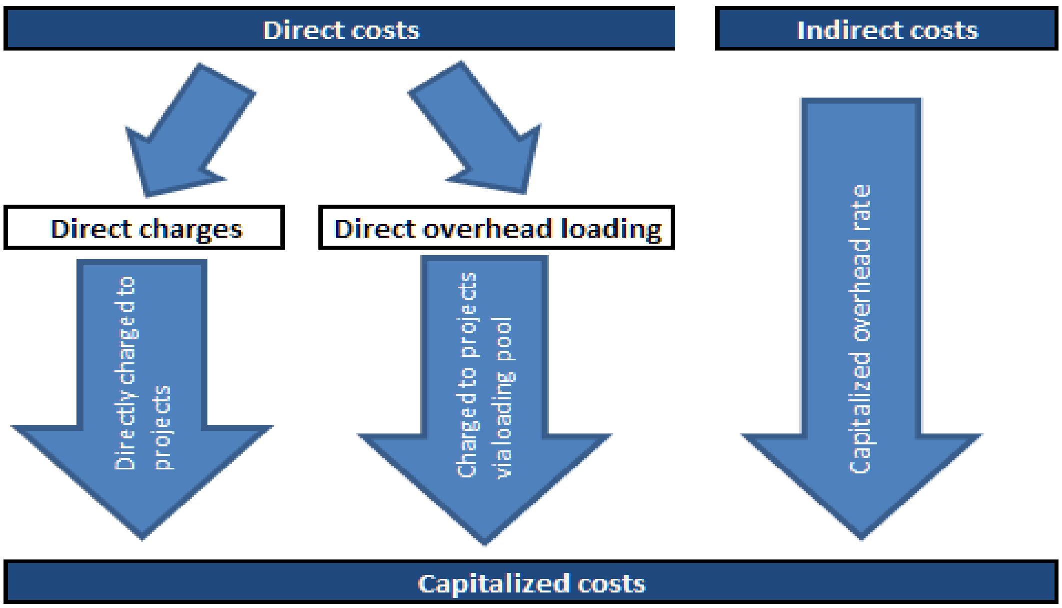
In 2011, the Company submitted its 2012–2013 Revenue Requirements Application to BCUC. The Application applied the same methodology as was submitted in 2006 and that was applied in the years 2006 to 2011 inclusive. The methodology was approved for the 2012-2013 term in Order G-110-12 and an overhead capitalization rate of **20 percent** was approved. However, BCUC also directed the Company to provide an external opinion on the appropriateness of its capitalized overhead methodology in the Company's next revenue requirements application.

In the same Decision, the Commission also instructed the Company to ensure that the Direct Overhead Loading methodology was commented on by an external party.

3.3 Background on Capital Cost Allocation Process

FBC allocates costs to capital projects through three mechanisms: direct charges to capital; direct overhead loading and capitalized overhead. This is illustrated in the following diagram:

Diagram 1: Capital cost allocation overview



For the direct overhead loading, FBC charges a recovery of supervisory and administrative costs that are not directly charged to specific capital projects but are directly associated with T&D capital projects. The purpose of the direct overhead loading is to allocate costs that relate to T&D capital projects specifically rather than having those costs included in the corporate capitalized overhead and allocated to Generation or other non-T&D capital projects. This methodology was introduced in the 2004 Revenue Requirements Application. A primary reason for this approach is due to the administrative burden associated with charging labour time and costs to individual projects. Instead, some direct costs are charged to a direct overhead loading pool. A mechanism is then used to charge the cost to individual projects on a prorated basis. Although it is possible to direct charge every cost to capital projects, this allocation mechanism is a much more efficient approach. A more detailed explanation of the process is found in Section 6 of this report.

4. Financial reporting framework

4.1 FBC Capitalization Policy

FBC follows the available U.S. and regulatory accounting guidance. FBC 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 Electric 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 Electric 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 FBC adopts should apply this basic principle.

4.4 Summary

The common principle and underlying methodologies employed by FBC for capitalizing costs related to capital activities that have not been directly charged to capital projects reflects a consistent approach under U.S. 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-based model approach, and also the mathematical model approach. KPMG also discussed with management the process undertaken, the nature of the costs and underlying documentation applied by management to determine the direct overhead loading cost pool. These are discussed further in Sections 6 and 7. 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 FBC with senior representatives from the operating and corporate support areas. The purpose of this step was to gain an understanding of the specific activities within FBC that may be related to capital. This step also provided KPMG with a good understanding of FBC'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 FBC's capital overhead cost allocation methodology was consistent with U.S. GAAP. A summary of the sources of our research is provided in Appendix C.
- **Step 4: Assessed the reasonableness of FBC's capital overhead cost allocation methodology.** In this step, we assessed the alignment between FBC'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, mathematical and direct overhead loading models against FBC'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 models 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 U.S. 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 direct overhead loading results against previously approved amounts;
  - Comparison of the results of the Survey-based Model against the Mathematical Model;
  - Compared with the results with previously approved capitalization rates; and
  - Comparison against other Canadian and U.S. utilities as observed through a review of regulatory filings in various jurisdictions.

6. Direct Overhead Loading Methodology and Results

In this Section we summarize the direct overhead loading methodology and the approach used to complete the study. Our work plan was developed in collaboration with FBC management.

6.1 Direct Overhead Loading Methodology

The following was applied to determine the direct overhead loading methodology by the Company:

6.1.1: Develop and document criteria for the direct overhead loading methodology based on guiding principles.

Management developed guiding principles for the direct overhead loading methodology and applied the following commonly used cost driver assessment principles when evaluating which cost driver should be used to allocate a cost.

	Internal FBC 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: Assessment of labour and non-labour costs. Each department estimates the amount of time by position and all non-labour related expense that should be charged to T&D projects via the direct overhead loading methodology. All of the costs are totalled to determine the direct overhead loading cost pool. Labour cost is determined based on standard labour rates multiplied by the numbers of estimated hours which are allocated to the direct overhead loading pool.

6.1.3: Compilation of data. Management compiled the results of the assessment of labour and non-labour costs in order to determine the total direct overhead loading pool.

6.1.4: Credit to departmental costs. These costs are removed from the departmental costs to which they relate prior to the determination of the capitalized overhead rate. The capitalized overhead rate is examined in Section 7.

6.2 Explanation and Results of Direct Overhead Loading Methodology

Under the direct overhead loading methodology, the Company performed a detailed analysis of the estimated capital related cost for each of the departments who performed work for T&D projects. This was determined by estimating the total time to be charged to capital projects on an employee basis or individual cost basis. For instance, Foreman X has a total of 1,600 available hours for the year. It was determined that 1,200 of those hours are T&D capital related.

In the case of labour costs, the specific amount of capital related time to be capitalized either through direct charges, or through direct overhead loading, is then estimated. For example, for the 1,200 hours of Foreman X, it was determined that 1,080 hours are estimated to be recorded to capital through direct charges. However, 10% of these hours, or 120 hours, would not be charged to specific projects and would be allocated to the direct overhead loading pool as the hours were capital related, but due to the associated administrative burden, were not charged to specific projects.

Having allocated the number of hours, these hours are multiplied by a labour cost rate, which reflects the costs of salary and related benefits.

For non-labour costs, the costs are generally either charged directly to projects, or if not, they are allocated to the direct overhead loading cost pool by management's estimated percentage that reflects the element which is related to capital.

As the direct overhead loading pool reflects costs which are primarily related to the T&D group and is not a corporate overhead allocation, there are a limited number of departments which are accounted for through this process.

Table 1 below shows the build-up of the direct overhead load pool based on the 2013 Budget. The table shows that a total of $4.7 million of overhead costs were allocated to the direct overhead pool and were therefore capitalized.

Table 1: Direct overhead loading results

Department	Function	2013 Direct Overhead Cost ($000s)
Operations - Okanagan	Management and Supervisory time	920
Operations - Kootenay	Management and Supervisory time	360
Project Management Office	Scheduling and administrative support	590
Engineering	Engineering and cost estimating	320
System Planning	T&D system planning & engineering	700
Environment, Health & Safety	Reporting, auditing project work.	60
Line Construction	Management and Supervisory time	370
Finance	Accounts payable	80
Procurement & Materials Handling	Supply chain support	150
Distribution Engineering	Capital engineering, design and cost estimating	120
Engineering Standards	T&D Standards development & maintenance.	160
System Control	System monitoring & communication	340
Station Capital	Supervisory & administrative support	140
Asset Management	Asset management planning & support	360
	Total	**4,670**

The total amount which has been capitalized under the direct overhead loading methodology is removed from O&M costs which have been used to determine the overhead capitalization rate in the Survey and Mathematical Models discussed in Section 7.

6.3 Comparison of Results with Prior Actual Direct Overhead Amounts

The direct overhead loading capitalized, which was determined by the direct overhead loading methodology, is **$4.7 million** for the 2013 Budget.

The methodology applied is consistent with the methodologies of 2011 and 2012, which resulted in actual direct overhead loadings of $5.4 million and $4.5 million respectively.

In the absence of future significant regulatory, accounting and organizational changes, the application of the direct overhead loading methodology may continue to be appropriate in future periods.

7. Overhead Capitalization Methodology and Results

In this Section we summarize the overhead capitalization methodology and the approach used to complete the study of FBC's overhead capitalization rate. Our work plan was developed in collaboration with FBC management and was designed to provide a supportable basis for the capitalization methodology.

FBC has examined two methodologies to determine the overhead capitalization rate – the "Survey Model" (based on inquiries and other supplemental information with business units) and the "Mathematical Model". These models are examined in Sections 7.2 and 7.3 respectively.

7.1 Capital Overhead Cost Methodology

The following methodology was applied to determine the capital overhead capitalization rate by the Company:

7.1.1: Develop and document criteria for capital cost allocation based on guiding principles.

Management developed guiding principles for the capital cost allocation methodology and applied commonly used cost driver assessment principles when evaluating which cost driver should be used to allocate a cost. These criteria are the same criteria applied in the evaluation of cost drivers for the direct overhead loading process, as presented in Section 6.1.

7.1.2: 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 FBC. The departments are summarized in Table 2 in Section 7.2.1.

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.

7.1.3: 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 2.

7.1.4: Survey Model - Comparison with previous interviews results. The results of the current interviews were also compared to the results of the previously approved BCUC capitalization rates. See results per Table 5.

7.1.5: Mathematical Model. FBC 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 7.3 below.

7.1.6: 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 7.5.

7.1.7: 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.

7.1.8: 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.

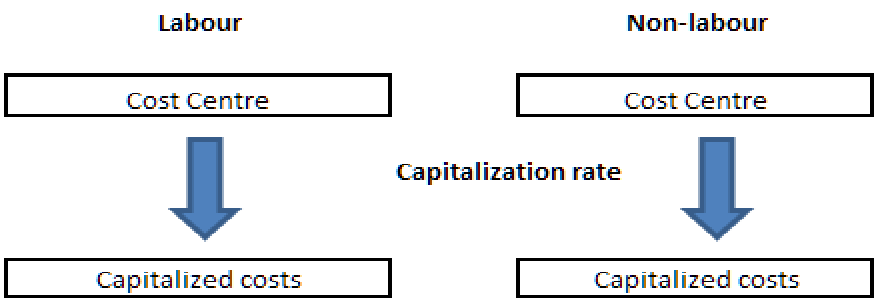
7.2 Explanation and Results of Survey Methodology

Under the Survey Model, the Company interviewed department heads and senior managers within the corporate functions and business units listed in Table 2. Management sought to understand and identify those company departments that support, either directly or indirectly, capital projects at FBC.

The purpose of this step was to gain an understanding of the specific activities within FBC that may be eligible to have costs allocated to capitalized activities. This step also provided KPMG with a good understanding of FBC'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 either directly, or through the direct overhead loading, as discussed in Section 6. That is, this residual is the O&M costs after direct charges performed by departments have been made to capital projects and after direct overhead loading charges for T&D. 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 2: 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 direct overhead loading and does not reflect the percentage of O&M costs which have been charged to capital through direct methods.

7.2.1 Survey Model Results

The results of this methodology suggested an overhead capitalization rate of approximately **15 percent**. Table 2 below shows the build-up of this rate for the FBC departments. As can be seen in Table 2, the larger departmental capitalization rates are Information Systems, Engineering Services and Operations Support. The total indirect capital related cost capitalized under this model is $8.5 million.

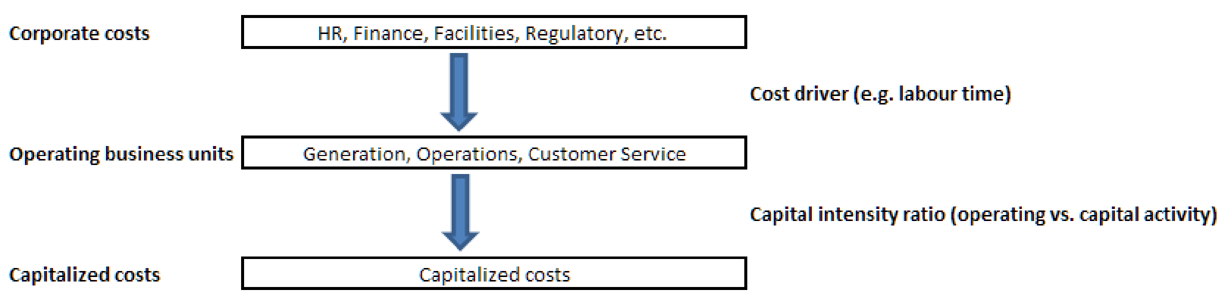
Table 2: Results of Survey Model (2013)

Department	Total Cost ($000s)	Indirect Capital Related ($000)	Capitalization Rate (%)
Generation	2,492	-	0.0%
Operations	20,817	3,563	17.1%
Customer Service	7,541	-	0.0%
Communications & External Relations	1,469	114	7.7%
Energy Supply	1,124	56	5.0%
Information Systems	2,974	954	32.1%
Engineering Services	2,791	890	31.9%
Operations Support	1,252	362	28.9%
Facilities	3,466	322	9.3%
Environment, Health & Safety	953	238	25.0%
Finance & Regulatory Services	4,271	1,123	26.3%
Human Resources	1,874	296	15.8%
Governance	2,373	149	6.3%
Corporate	4,225	465	11.0%
Totals	**57,621**	**8,531**	**14.8%**

7.3 Explanation and Results of Mathematical Model Methodology

FBC 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 and after direct overhead loading to capital projects. The process is illustrated as follows:

Diagram 3: Mathematical Model illustration



The details of the two-step process are as follows:

Step A: 100% allocation of corporate costs into the three FBC operating business units

The various corporate functions of the Company are allocated to the three operating business units which they support (Generation, Operations 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 Generation, Operations and Customer Service employee count in 2013;
- Total expenditures - total expenditure on O&M and capital; and
- Labour time estimate - representing approximate time spent supporting each business unit.

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 $1.9 million are allocated 23.3 percent (97 of 416 employees) or $0.4 million to Generation, 60.1 percent or $1.1 million to Operations and 16.6 percent or $0.4 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 Generation, Operations 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 and direct overhead loading to capital projects in Generation, Operations and Customer Service), undergo no further allocation to capital activities as the capital intensity ratio determines the capital related element for each of the business units. In the Survey-based approach, the business units are reviewed for allocation to capital in the same manner as corporate costs. For example, under the Survey Model (as shown in Table 2), Operations have a $3.6 million charge to capital; however, in the Mathematical Model (as shown in Table 4) the Operations costs do not get allocated as an individual group.

7.3.1 Mathematical Model Results

The results of this methodology suggested an overhead capitalization rate of approximately **17 percent**.

The corporate functions, their drivers and the resulting allocations between the business units for 2013 are summarized in Table 3 below.

Table 3: Determination of Corporate Support Levels by Operating Unit (2013)

		Percent Allocated to		
Department	Driver	Generation	Network Services	Customer Service
Communications & External Relations	Labour time estimate	16.5%	35.3%	48.2%
Information Systems	Labour time estimate	20.0%	40.0%	40.0%
Facilities	Employee count	23.3%	60.1%	16.6%
Environment, Health & Safety	Employee count	23.3%	60.1%	16.6%
Finance & Regulatory Services	Total expenditure	15.0%	55.7%	29.3%
Human Resources	Employee count	23.3%	60.1%	16.6%
Governance	Total expenditure	15.0%	55.7%	29.3%
Corporate	Total expenditure	15.0%	55.7%	29.3%

The capital intensities of the operating business units are: 72 percent for Generation, 57 percent for Operations and 7 percent for Customer Service. The capital intensity ratios are determined using the methodology described in Step B above. For example, of the $0.4 million of Human Resources costs representing support to Generation, 72 percent or $0.3 million would relate to capital work. In total, of the $1.9 million of O&M Expense for Human Resources, $1 million is forecast to be allocated by way of capitalized overhead for Generation, Operations and Customer Service, which compares to $0.3 million under the Survey-based Model in Table 2.

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 4, 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 $9.8 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 4: Application of Unit Factors to Calculate Capitalized Overhead (2013)

Capital Intensity Ratio	72%	57%	7%			
	$000 Allocated to					
Department	Generation	Operations	Customer Service	Capital Related ($000s)	Total Cost ($000s)	Capitalization Rate (%)
Communications & External Relations	174	295	50	519	1,469	35.4%
Information Systems	428	678	83	1,190	2,974	40.0%
Facilities	582	1,187	40	1,809	3,466	52.2%
Environment, Health & Safety	160	327	11	498	953	52.2%
Finance & Regulatory Services	461	1,357	87	1,905	4,271	44.6%
Human Resources	315	642	22	978	1,874	52.2%
Governance	256	754	49	1,059	2,373	44.6%
Corporate	456	1,342	87	1,885	4,225	44.6%
Generation					2,492	
Operations					20,816	
Customer Service					7,541	
Energy Supply					1,124	
Engineering Services					2,791	
Operations Support					1,252	
TOTALS	2,832	6,582	429	9,843	57,621	17.1%

7.5 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 previously approved BCUC overhead capitalization rate for the Company.

Table 5: Comparison between Models and previously BCUC approved overhead capitalization rate

Current study		
Survey Model	**Mathematical Model**	**Previously Approved Rate by BCUC**
15 %	**17%**	**20%**[1]

The results of the models show that the Survey-based Model produces a lower overhead capitalization rate than the Mathematical Model. This is the result of the high capital intensity ratios under the Mathematical Model within the business units, in particular, the Generation group, where 72% of all allocated corporate support costs are capitalized. This causes a greater level of overhead capitalization compared to the Survey-based model for the corporate support functions. These rates exclude direct overhead loading.

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 more appropriate capitalization rate is approximately 15 percent.

[1] This rate excludes the impact of direct overhead loading.

7.6 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 FBC 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 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 U.S. ranged from 7.33% to <50% with a median of 19%[2].

[2] http://www.hydroone.com/RegulatoryAffairs/Documents/EB-2012-0031/Exhibit%20C/C1-07-02.pdf

8. KPMG Evaluation

8.1 Overview of Evaluation Conducted

KPMG finds the FBC direct overhead loading and survey-based capital cost allocation methodology, as detailed in Sections 6 and 7 of this report, to be a reasonable basis for capitalization of costs related to capital activities, as examined in the evaluation criteria discussed below. These methodologies are consistent with FBC'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 8 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 FBC that may be related to or directly attributable to capital. Section 8.6 of this report details KPMG's review coverage of FBC's O&M costs assessed as eligible for capitalization. This was based on attendance at select FBC business group survey interviews and review of allocation calculations prepared by FBC.

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.

8.2 Commentary on Direct Overhead Loading Methodology

The direct overhead loading rate background is discussed in Section 3.3 of this report. The direct overhead loading cost pool is determined through a process of labour and cost estimation for the amount of time and expense which should be charged to T&D projects, which have not been directly charged. Once this estimation process has been completed, it is removed from the O&M cost pool which is used in determining the capitalized overhead rate.

The T&D cost allocation basis which is being used to allocate costs into the direct overhead loading cost pool is similar to the allocation bases which are discussed below under Section 8.5 for the cost allocation overhead model. That is, an estimation of time (or cost) by FBC management is used as a basis for the purpose of the allocation. As these costs are removed from the O&M pool this allocation process functions in a similar manner to direct charges to specific capital projects.

This direct overhead loading process does not result in a duplication of the level of overhead which is capitalized, as the evaluation of the capitalized overhead rate is conducted with these direct overhead loading costs excluded from the remaining corporate cost pool being evaluated.

KPMG finds that the process to allocate costs to the direct overhead loading pool prior to the capitalized overhead rate determination should not impact the overall capitalized overhead being recorded, as the evaluation conducted for capitalized overhead has been performed with these direct overhead loading costs having been excluded.

8.3 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 (noted per Section 6.1) in order to be able to evaluate the appropriateness and reasonableness of the direct overhead loading and capital overhead methodology, which are described in Section 6 and 7 of this report respectively.

8.3.1 Reasonability of the Evaluation Criteria Used to Assess FBC Cost Allocation Methodology

In Step 4 KPMG reviewed the internally generated Evaluation Criteria used by FBC to assess the cost allocation methodology. Table 6 provides a summary of these Evaluation Criteria principles that are consistent with Management's assessment principles as described in Section 6.1.

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.

8.3.2 Reasonability of a) the Survey Model, b) the Mathematical Model and c) the direct overhead loading methodologies against the internally generated Evaluation Criteria of FBC

In Step 4 KPMG also assessed FBC's capital cost allocation methodology against FBC's internal criteria as outlined in Section 6.1 of this Study. These assessment criteria are provided in the table below.

Table 6: Evaluation of Capital Overhead Allocation Methodology

		Assessment		
Evaluation Criteria	**Explanation**	**Direct overhead loading**	**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.	✓	✓	✓

		Assessment		
Evaluation Criteria	**Explanation**	**Direct overhead loading**	**Mathematical Model**	**Survey Model**
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.	✓✓	✓	✓✓
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 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			

Direct overhead loading model

KPMG finds that the direct overhead loading methodology which allocates direct capital charges to T&D capital projects is consistent with previously approved rate filings and consistent with FBC's internally generated criteria for overhead capitalization.

Survey and Mathematical Model

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.

8.4 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) Project specific costs not directly charged to individual projects

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 costs which have not been direct charged to projects due to time/cost constraints. The costs which typically comprise the direct overhead loading costs are of such a nature, for T&D costs.

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 Generation, Operations and Customer Service), overhead costs are allocated to capital as a result of the non-project specific and direct oversight costs within these groups. No indirect overhead is capitalized in the Customer Service group (under the Survey-based model) as this group directly charges any applicable costs to capital.

Certain activities are difficult to directly relate to capital, including for example, Information Systems and Human Resources as they are removed from actually performing the capital work and represent support functions; however FBC 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.

8.5 Evaluation of Cost Drivers used to Allocate Costs to Capital

In Step 6 KPMG analyzed the nature of the drivers used by FBC to allocate costs to capital projects. The cost drivers under the direct overhead loading methodology, Mathematical Model and the Survey-based Model are different and are evaluated separately below.

8.5.1 Direct overhead loading

Under the direct overhead loading process, the direct overhead pool is determined differently for labour and non-labour costs. The allocation is based on the following:

- **Labour Time Estimate**

  For the labour cost component of departments which are subject to direct overhead loading, 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. The estimate factors into account the amount of time which will be direct charged, with the direct overhead loading hours being the residual.

KPMG finds the allocation basis applied to determine the capital related component for labour is consistent with the internally generated Evaluation Criteria established by FBC.

- **Budgeted Cost Amount**

  For the non-labour cost component of departments which are subject to direct overhead loading, the allocation of non-labour costs was performed based on management's estimate of the costs which are related to capital activities.

KPMG finds the allocation basis applied to determine the capital related component for non-labour is consistent with the internally generated Evaluation Criteria established by FBC.

8.5.2 Survey-based Model

Under the Survey-based 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 FBC 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 7.2.1.

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 FBC.

- **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 FBC.

8.5.3 Mathematical Model

KPMG assessed the reasonability of the drivers used to allocate overhead costs to the business units. Under this model, the corporate costs, noted in Table 3, 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 Generation, Operations 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 FBC.

- **Total Expenditure**

  For certain corporate functions, noted in Table 3, 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 FBC.

- **Labour time estimate**

  FBC has determined that a number of corporate functions noted in Table 3, 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 FBC.

8.6 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 in this report, all figures which have been applied in all three models (Survey, Mathematical and the direct overhead loading model) relate to the 2013 Budget.

KPMG performed the following procedures:

1. **<u>Assessment of underlying cost population and cost resources</u>**
   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. **<u>Assessment of allocation bases (cost drivers)</u>**

   In conjunction with understanding the allocation bases, KPMG traced the allocation bases to source calculations. As three models were used, the procedure differed slightly.
   a. For the direct overhead loading process:
      i. We held discussions with management to review the cost allocations which had been applied;
      ii. We re-performed the calculations prepared by management of the direct overhead cost pool.
   b. 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 Generation, Network Operations and Customer Service.

c. For the Survey Model:
    i. We verified total expenditures to the 2013 Budget figures;
    ii. We attended interview discussions with department managers where estimated labour cost time was determined. Specifically, we attended interviews related to departments which comprised approximately $7 million out of the $8.5 million of costs allocated to capital.
    iii. We re-performed the calculations prepared by management of the capitalized overhead rate.

3. Other regulatory filings

An external survey was conducted by FBC 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.

FBC 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 FBC 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 7: Comparison to industry findings

Utility	Jurisdiction	Accounting Framework	Overhead Rate
Heritage Gas	Nova Scotia	U.S. GAAP	59.2%[3]
Enbridge Gas	New Brunswick	U.S. GAAP	44.8%
Enbridge Gas	Ontario	U.S. GAAP	19.8%
AltaGas	Alberta	U.S. GAAP	16%
Union Gas	Ontario	U.S. GAAP	15%
Hydro One Networks Inc.	Ontario	U.S. GAAP	9%
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 FBC. It is noted that the rates for FBC 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 FBC.

These procedures performed do not constitute an audit of the capitalization cost allocation methodology or allocated capitalization percentage of O&M costs.

[3] 2010 actual

8.7 Assessment of the resulting capitalization rates

In Step 8 KPMG assessed the methodology and resulting values utilized in the Survey-based model against FBC's proposed capital cost allocation methodology.

As described in Section 8.6 of this report, certain procedures were conducted to assess the accuracy of FBC's underlying 2013 budgeted costs and allocation bases used to calculate the allocation of costs to capital within the model.

KPMG finds the FBC direct overhead loading process and Survey-based model and the underlying costs to be consistent with the cost allocation methodologies and evaluation criteria as proposed by FBC and guidance related to U.S. GAAP.

Based on the results of the Survey Model, the estimated overhead capitalization rate is approximately 15 percent.

Based on the results of the direct overhead loading model, the estimated direct overhead loading pool is $4.7 million.

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 U.S. 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 it was 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 U.S. 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 FBC'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	Operating, Supervision and Miscellaneous; Tools,	6.8% of gross O&M based on the 2013	http://www.pub.nf.ca/applications/NP2

Canadian Utilities				
Utility	**Accounting Standard**	**Overhead Cost Elements**	**Capitalization Rate**	**Reference**
	effective January 1, 2012	Equipment, Safety Clothing and Uniforms; Accounting; Printing and Stationery; Employees' Welfare; HR Planning and Administration; Human Resource Services; and Company Pension Plan.	Forecast.	012Capital/files/applic/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 reported 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[4]:

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 U.S. 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.

[4] 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.

Other sources:

- BCUC *Uniform System of Accounts Prescribed for Electric Utilities*
- FERC *Uniform System of Accounts*

Appendix F4

DEFERRED CHARGES

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Energy Policy	Demand Side Management	G-123-98; G-58-06	Captures the costs of FBC's PowerSense programs and initiatives to promote energy efficiency for customers	15 years proposed. See Appendix H2.
Energy Policy	On-Bill Financing (OBF) Pilot Program	G-163-12	A non rate base deferral account capturing the costs of the OBF Pilot Program. Pursuant to Order G-163-12 FBC will transfer the balance of this account to rate base effective January 1, 2015.	15 years proposed. See Section D4.4.2.
Energy Policy	On-Bill Financing (OBF) Participant Loans	G-163-12	A non rate base deferral account capturing the costs of the OBF Participant Loans. FBC is requesting approval to transfer the balance of this account as at December 31, 2014 to rate base effective January 1, 2015.	10 years. See Section D4.5.2
Revenue and Power Supply Variances	Rate Stabilization Deferral Mechanism (RSDM)	Requested	Establishes an amount of revenue to be utilized for the purpose of mitigating rate variability over the period 2014 – 2018.	5 years proposed: see Section D4.3.1.
Revenue and Power Supply Variances	Power Purchase Expense Variance	G-110-12	Captures variances between forecast and actual power purchase expense and water fees.	1 year
Revenue and Power Supply Variances	Revenue Variance	G-110-12; C-4-13	Captures variances in sales revenue , including from the City of Kelowna acquisition, the majority of which are attributable to weather related load variances, customer usage rate variances and customer count load variances.	1 year

Appendix F4
FBC Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Revenue and Power Supply Variances	Generic Cost of Capital Revenue Requirements Impact	requested	Captures the effect on interim 2013 rates of the reduction in benchmark Return on Equity effective January 1, 2013, and potential further adjustments arising from a decision in Stage 2 of the proceeding.	2 years proposed. See Section D4.3.4
Non-controllable	Pension & Other Post-Retirement Benefits Expense Variance	G-110-12	Captures the variance between actual pension and OPEB expense and the amount forecast in rates	EARSL proposed. See Section D4.4.4
Non-controllable	Prepaid Pension Costs and OPEB Liability	G-110-12	Captures the difference between the actuarially determined expense and the contributions paid by the Company.	Life of the employee future benefits.
Non-controllable	US GAAP Pension and OPEB Transitional Obligation	G-110-12	Recognizes the transitional obligation of pensions and OBEBS on transition to US GAAP effective January 1, 2012.	12 years.
Non-controllable	Insurance Expense Variance	Requested	Captures the variance between actual insurance expense and the amount forecast in rates.	1 year proposed. See Sections C4.16.1 and D4.3.5
Non-controllable	Interest Expense Variance	Requested	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 proposed. See Sections D1.1.5 and D4.3.6
Non-controllable	Tax Variance	Requested	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 proposed. See Sections D2.4.1 and D4.3.7
Non-controllable	Property Tax Variance	Requested	Captures the variance between actual property taxes and the amount forecast in rates.	3 years proposed. See Sections D-2.2.31

Appendix F4
FBC Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Preliminary and Investigative	Preliminary and Investigative Charges	Uniform System of Accounts Section 183	Costs incurred in determining the feasibility of projects for utility services. Upon commencement of the projects, the costs are transferred to the capital project. For regular capital projects the costs are included in rate base. For projects subject to CPCN approval costs are excluded from rate base.	n/a
Preliminary and Investigative	Kelowna Bulk Transformer Capacity Addition (KBTCA) Project	G-110-12	Preliminary and feasibility costs associated with the KBTCA Project. Project is delayed beyond 3 years of deferred expenditures and costs will be amortized into rates.	1 year. See Sections C5.3.3 and D4.5.2
Regulatory Compliance	2014 - 2018 PBR Application	G-110-12	Captures costs related to the 2014 – 2018 PBR application and 2014 revenue requirements.	5 years proposed. See Section D4.4.3
Regulatory Compliance	2014 – 2018 Annual Reviews	Requested	Captures costs of Annual Reviews for setting of rates during the PBR Period.	1 year proposed. See Section D4.3.9
Regulatory Compliance	BC Hydro Application for a Power Purchase Agreement with FBC	Requested	Captures costs of participation in BC Hydro's application for approval of a new Power Purchase Agreement with FBC.	1 year proposed. See Section D4.3.3.
Regulatory Compliance	BCUC Generic Cost of Capital Proceeding	G-23-13	Captures the costs related to the GCOC Proceeding Phase 1 and Phase 2. See Section D3 for further discussion.	2 years proposed. See Section D4.4.~~5~~8
Regulatory Compliance	BCUC Inquiry into the MRS Program	G-23-13	Captures costs of participation in the BCUC review of the BC Mandatory Reliability Standards program.	1 year proposed. See Section D4.4.~~6~~9.
Regulatory Compliance	Kettle Valley Expenditure Review	G-23-13 G-47-13	Captures costs incurred in the review of the Kettle Valley Distribution Source Project	1 year proposed. See Section D4.4.~~7~~10.
Regulatory Compliance	Transmission Customer Rate Design	G-188-11: G-202-12: G-23-13	Captures costs of to develop new rate schedules for self-generating customers, transmission customers, and a standby rate for Celgar. To be discontinued	1 year proposed. See Section D4.4.~~8~~11.
Regulatory Compliance	City of Kelowna Acquisition Legal and Regulatory Costs	C-4-13	Captured closing, regulatory process and legal costs to a maximum of $0.5 million To be discontinued	1 year requested. See Section D4.4.12

Appendix F4
FBC Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Other	Earnings Sharing Mechanism (ESM) Deferral	Requested	Captures the customer portion of Earnings Sharing for return to or recovery from customers in the subsequent year	1 year proposed. See Section D4.3.2
Other	Right of Way Reclamation (Pine Beetle Kill)	G-147-07	Captures the costs of the 2008 ROW expenditures from Mountain Pine Beetle damage.	10 years
Other	2012 Integrated System Plan - Engineering	G-110-12	Captures the engineering costs for preparing FBC's 2012 long term Integrated System Plan	5 years
Other	2014 – 2018 Capital Expenditure Plan	G-110-12	Captures the engineering costs of preparing FBC's 2014 – 2018 Capital Expenditure Plan.	2 years proposed. See Section D4.4.13.
Other	2012 Mandatory Reliability Standards Audit	G-23-13	Captures the cost of the 2012 WECC Audit of FBC's MRS program. To be discontinued	1 year proposed. See Section D4.4.~~9~~12.
Other	Mandatory Reliability Standards 2012 -2013 Incremental O&M Expense	G-23-13	Captures the cost of the incremental O&M incurred in 2012 and 2013 to maintain compliance with the BC MRS. To be discontinued.	1 year proposed. See Section D4.4.1~~0~~3.
Other	City of Kelowna Acquisition Customer Benefit	C-4-13	Captured the 2013 Customer Benefit resulting from FBC's purchase of the utility assets of the City of Kelowna, including an adjustment to the Revenue Variance account. To be discontinued.	1 year proposed. See Section D4.4.11.
Other	Deferred Debt Issue Costs	various	Captures fees for auditors, legal, dealers, filings, rating agencies and trustees as required for the issuance of debt.	Term of Debentures. See Section D4.5.9.
Residual	2011 Flow-Through and ROE Sharing Mechanism Adjustments	G-110-12	Captured flow-through and customer share of ROE mechanism for 2011.	1 year.
Residual	2012 Deferred Revenue	G-159-12 C-4-13	Deferred interim rate overcollection in 2012 due to timing of RRA decision	1 year.
Residual	Harmonized Sales Tax Removal/ Provincial Sales	G-110-12	Captured implementation and expense impacts of the reinstatement of BC PST.	1 year.

Appendix F4
FBC Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
	Tax Implementation			
Residual	Section 71 Filing (Waneta Expansion Power Purchase Agreement)	G-184-10	Captured legal, regulatory and other costs associated with the power purchase agreement	3 years. See Section D4.5.4.
Residual	Cost of Service and Rate Design Application	G-147-07; G-184-10	Captured incremental costs of FBC's 2009 Cost of Service Allocation and Rate Design Application	4 years
Residual	2012 - 2013 Revenue Requirements and 2012 Integrated System Plan	G-184-10; G-110-12	Captured incremental costs of regulatory process for FBC's 2012-13 RRA and 2012 ISP	2 years
Residual	2011 Revenue Requirement Application Costs	G-152-09	Captured incremental costs of 2011 revenue requirements application	1 year
Residual	Residential Inclining Block Rate	G-156-10; G-24-11	Captured costs of developing and regulatory review of FBC's Residential Conservation Rate	1 year.
Residual	Implementation of New Rate Structures	G-24-11; G-110-12	Captured costs of implementing new rate structures including expenditures to modify FBC's Customer Information System and bill formatting software.	1 year.
Residual	Irrigation Rate Payer Group Consultation and Load Research	G-156-10; G-110-12	Captured costs of undertaking load research related to FBC's irrigation customers	1 year.
Residual	Negotiation of new PPA between BC Hydro and FBC	G-193-08; G-110-12	Captures costs of negotiating a new PPA (RS 3808) with BC Hydro??	2 years. See Section D4.5.5
Residual	Right of Way Encroachment Litigation	G-193-08; G-110-12	Captures legal costs associated with an ongoing litigation matter with a land developer in Kelowna, British Columbia.	1 year. See Section D4.5.6
Residual	Trail Office Lease Cost	G-41-94; G-110-12	Captured legal and other fees associated with the lease of the Trail Office.	Extinguished in 2013. See Section D4.5.7.
Residual	Trail Office Rental to SD20	G-41-94; G-110-12	Prepaid rental and strata title for space in Trail Office.	Extinguished in 2013. See Section D4.5.8.

Appendix F4
FBC Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Residual	Princeton Light and Power Deferred Pension Credit	G-159-06	Transferred deferred account at merger of PLP with FBC	7 years.
Residual	US GAAP Conversion Costs	G-162-09; G-110-12	Captured the one-time conversion costs associated with the adoption of US GAAP during 2011.	2 years.
Residual	Joint Pole Use Audit, 2013	G-110-12	Captured 2013 costs of 5-year audit of joint pole use agreements	2 years.
Residual	Demand Side Management Study	G-184-10	Captured costs to complete the Residential and Commercial End-Use Surveys and to initiate a Conservation and Demand Potential Review	3 years.
Residual	Mandatory Reliability Standards Implementation	G-162-09; G-110-12	Captured initial compliance related to BC's new MRS program	3 years.
Residual	Revenue Protection	G-110-12	Captured costs of FBC's Revenue protection activities in 2011	1 year.

Appendix F5

2012 REGULATED TO EXTERNAL FINANCIAL STATEMENTS INCLUDING CGAAP RECONCILIATION

APPENDIX A
RECONCILIATION OF FINANCIAL STATEMENTS

STATEMENT OF EARNINGS, CORPORATE AND REGULATORY
YEAR ENDED DECEMBER 31, 2012

	Corporate US GAAP (external)	US GAAP Adjustment	Corporate Canadian GAAP	Regulated Adjustment	Regulated
			($000s)		
REVENUE					
Sale of power	285,019		285,019	(2,076)	282,943
Other	8,387		8,387	779	9,166
	293,406	-	293,406	(1,297)	292,109
EXPENSES					
Power purchase costs	75,999		75,999	-	75,999
Operating costs	73,294	-	73,294	(30,721)	42,573
Wheeling	-		-	4,813	4,813
Property taxes	-		-	13,912	13,912
Water fees	-		-	9,253	9,253
Depreciation and Amortization of Deferreds	48,509		48,509	79	48,588
	197,802	-	197,802	(2,664)	195,138
EARNINGS FROM OPERATIONS	95,604	-	95,604	1,367	96,971
OTHER INCOME	1,154		1,154	(1,050)	104
INTEREST EXPENSE	38,925		38,925	(38,925)	-
Long-term debt	-		-	38,422	38,422
Short-term debt	-		-	265	265
	38,925	-	38,925	(238)	38,687
REGULATORY INCENTIVE ADJUSTMENTS	-		-	781	781
EARNINGS BEFORE INCOME TAXES	57,833	-	57,833	(226)	57,607
INCOME TAXES	8,811		8,811	286	9,097
NET EARNINGS	**49,022**	**-**	**49,022**	**(512)**	**48,510**

Note: Minor differences due to rounding.

RECONCILIATION OF STATEMENT OF EARNINGS
CORPORATE TO REGULATORY

	($000s)
Sale of Power	285,019
Walden Power Partnership	(2,076)
Regulated	282,943
Other Revenue	8,387
Reclass Incentives and Flowthrough Adjustment	781
Walden Power Partnership	(2)
Regulated	9,166
Operating costs	73,294
Non-Regulated	(1,432)
Walden Power Partnership	(765)
Wheeling	(4,813)
Property taxes	(14,332)
Water fees	(9,379)
Regulated	42,573
Wheeling	-
Reclass from Operating costs	4,813
Regulated	4,813
Property Taxes	-
Reclass from Operating costs	14,332
Walden Power Partnership	(420)
Regulated	13,912
Water Fees	-
Reclass from Operating costs	9,379
Walden Power Partnership	(126)
Regulated	9,253
Depreciation and Amortization of Deferreds	48,509
Reclass from Amortization of Deferred Financing Costs	415
Non-Regulated Warfield Garage Expansion	(14)
Walden Power Partnership	(322)
Regulated	48,588

	($000s)
Other Income	1,154
Non-Regulated Interest Income	(8)
Walden Power Partnership Interest Income	(4)
Non-Regulated AFUDC - Equity Component	(1,038)
Regulated	104
Interest Expense	38,925
Reclass to Interest Expense - Long-term Debt	(38,422)
Reclass to Interest Expense - Short-term Debt	(265)
Reclass to Amortization of Deferred Financing Costs	(415)
Non-Regulated AFUDC - Debt Component	916
Walden Power Partnership	(140)
Non-Regulated Interest	(599)
Regulated	-
Interest Expense - Long-term Debt	-
Reclass from Interest Expense	38,422
Regulated	38,422
Interest Expense - Short-term Debt	-
Reclass from Interest Expense	265
Regulated	265
Regulatory Incentive Adjustments	-
Reclass Incentives and Flowthrough Adjustment	781
Regulated	781
Income Taxes	8,811
Non-Regulated	286
Regulated	9,097

Note: Minor differences due to rounding.

BALANCE SHEET, CORPORATE AND REGULATORY
AS AT DECEMBER 31, 2012

	Corporate US GAAP (external)	US GAAP Adjustment	Corporate Canadian GAAP	Regulated Adjustment	Regulated
			($000s)		
ASSETS					
Plant and Equipment & Intangibles	1,782,220	(259,363)	1,522,857	92,599	1,615,456
Less accumulated depreciation	(414,034)	43,031	(371,003)	(24,820)	(395,823)
	1,368,186	(216,332)	1,151,854	67,779	1,219,633
Other Assets	6,685	(158)	6,527	5,761	12,288
Regulated Assets	285,079	(138,395)	146,684	(146,684)	-
Non-Rate Base Assets	-	-	-	161,152	161,152
	291,764	(138,553)	153,211	20,229	173,440
Goodwill	220,718	(219,509)	1,209	(1,209)	-
Current Assets		-			
Cash	1,762	-	1,762	(598)	1,164
Accounts receivable	39,834	-	39,834	1,680	41,514
Prepaid expenses	957	-	957	(28)	929
Other assets	398	-	398	(398)	-
Inventory	469	-	469	-	469
Regulated assets	6,327	-	6,327	(6,327)	-
Deferred income taxes	647	-	647	(647)	-
	50,394	-	50,394	(6,318)	44,076
TOTAL ASSETS	**1,931,062**	**(574,394)**	**1,356,668**	**80,481**	**1,437,149**
CAPITAL AND LIABILITIES					
Capitalization					
Shareholder's Equity					
Common shares	523,615	(321,764)	201,851	(21,729)	180,122
Retained earnings	186,081	102,255	288,336	4,865	293,201
Total Shareholder's Equity	709,696	(219,509)	490,187	(16,864)	473,323
Long-Term Debt					
Secured debentures	25,000	-	25,000	-	25,000
Unsecured debentures	600,000	-	600,000	-	600,000
Term bank loans and other	34,977	-	34,977	-	34,977
Debt Issue Costs	-	(5,201)	(5,201)	5,201	-
Total Long-Term Debt	659,977	(5,201)	654,776	5,201	659,977
Contributions in Aid of Construction	-	-	-	97,671	97,671
Capital Lease and Finance Obligations (non-rate base)	312,395	(287,326)	25,069	462	25,531
Pension and other post-employment benefits (non-rate base)	80,532	(61,591)	18,941	-	18,941
Asset Retirement Obligation (non-rate base)	2,785	-	2,785	-	2,785
Other Liability	874	-	874	(874)	-
Regulated Liability - Long-term	6,963	-	6,963	(6,963)	-
Deferred Income Taxes (non-rate base)	110,339	-	110,339	(137)	110,202
Deferred Income Taxes	-	-	-	418	418
	513,888	(348,917)	164,971	(7,094)	157,877
Current Liabilities					
Accounts payable and accrued liabilities	41,776	(767)	41,009	(1,105)	39,904
Current portion of debt	925	-	925	(925)	-
Current Portion of Capital Lease Obligation	462	-	462	(462)	-
Regulated liability	1,969	-	1,969	(1,969)	-
Income taxes payable	260	-	260	799	1,059
Accrued interest	-	-	-	7,338	7,338
Deferred income taxes	2,109	-	2,109	(2,109)	-
Bank loans	-	-	-	-	-
	47,501	(767)	46,734	1,567	48,301
TOTAL CAPITAL AND LIABILITIES	**1,931,062**	**(574,394)**	**1,356,668**	**80,481**	**1,437,149**

Note: Minor differences due to rounding.

RECONCILIATION OF BALANCE SHEET
AS AT DECEMBER 31, 2012

ASSETS	($000s)
Plant and Equipment & Intangibles (US GAAP)	1,782,220
Brilliant Power Purchase Agreement Lease	(252,826)
Trail Office Building Lease	(6,537)
Plant and Equipment & Intangibles (CGAAP)	1,522,857
Contributions in Aid of Construction	147,743
Non-Regulated Warfield Garage Expansion	(246)
Capital Lease Asset (non-rate base)	(28,110)
Asset Retirement Obligation (non-rate base)	(2,943)
Walden Power Partnership	(23,845)
Regulated	1,615,456
Accumulated Depreciation (US GAAP)	(414,034)
Brilliant Power Purchase Agreement Lease Accum Depn	39,926
Trail Office Building Lease Accum Depn	3,105
Accumulated Depreciation (CGAAP)	(371,003)
Contributions in Aid of Construction Accum Depn	(50,072)
Kettle Valley Accum Depn Adjustment	835
Non-Regulated Warfield Garage Expansion Accum Depn	113
Capital Lease Accum Depn (non-rate base)	8,445
Asset Retirement Obl. Accum Depn (non-rate base)	1,782
Walden Power Partnership Accum Depn	14,077
Regulated	(395,823)
Other Assets (Deferred Charges) (US GAAP)	6,685
Reclass Prepaid Pension Asset	5,043
Reclass to Debt Issue Costs	(5,201)
Other Assets (Deferred Charges) (CGAAP)	6,527
Reclass to Accounts Receivable	(1,484)
Reclass from Regulated Assets - Current	6,327
Reclass from Regulated Assets - Long-term	5,523
Reclass from Debt Issue Costs	4,418
Reclass from Other Liability	(874)
Reclass from Regulated Liability - Long-term	(6,180)
Reclass from Regulated Liability - Current	(1,969)
Regulated	12,288
Regulated Assets - Long-term (US GAAP)	285,079
Pension & OPEB Funded Status Adjustment	(63,244)
Pension & OPEB Transitional Asset	(4,157)
Brilliant Power Purchase Agreement Lease	(63,059)
Trail Office Building Lease	(7,935)
Regulated Assets - Long-term (CGAAP)	146,684
Reclass to Other Assets (Deferred Charges)	(5,523)
Non-Rate Base Reg Assets	(141,161)
Regulated	-
Non-Rate Base Assets	-
Other Post-Retirement Benefits Regulated Asset	18,941
BTS Lease Costs Regulated Asset	5,865
Deferred Income Tax Regulated Asset	110,202
Asset Retirement Obligation Regulated Asset	1,624
Advanced Metering Infrastructure (AMI) Costs Reg Asset	2,650
Kettle Valley Prudency Review Costs Reg Asset	1,879
Subtotal Non-Rate Base Reg Assets	141,161
Kettle Valley Accum Depn Adjustment	(835)
Capital Lease Asset (non-rate base)	28,110
Capital Lease Accum Dep (non-rate base)	(8,445)
Asset Retirement Obligation (non-rate base)	2,943
Asset Retirement Obl. Accum Depn (non-rate base)	(1,782)
Regulated	161,152
Goodwill (US GAAP)	220,718
Pushdown Adjustment	(219,509)
Goodwill (CGAAP)	1,209
Non-Regulated	(1,209)
Regulated	-
Cash	1,762
Walden Power Partnership	(598)
Regulated	1,164
Accounts Receivable	39,834
Reclass from Deferred Charges	1,484
Reclass from Current Other Assets	398
Non-Regulated	(133)
Walden Power Partnership	(69)
Regulated	41,514
Prepaid Expenses	957
Walden Power Partnership	(28)
Regulated	929
Other Assets - Current	398
Reclass to Accounts Receivable	(398)
Regulated	-
Regulated Assets - Current	6,327
Reclass to Deferred Charges	(6,327)
Regulated	-
Deferred Income Tax Asset	647
Reclass to Long-term DIT Liability	(647)
Regulated	-

CAPITAL AND LIABILITIES	($000s)
Common Shares (US GAAP)	523,615
Pushdown Adjustment	(321,764)
Common Shares (CGAAP)	201,851
Non-Regulated	(21,729)
Regulated	180,122
Retained Earnings (US GAAP)	186,081
Pushdown Adjustment	102,255
Retained Earnings (CGAAP)	288,336
Non-Regulated	4,865
Regulated	293,201
Debt Issue Costs (US GAAP)	-
Reclass from Other Assets (Deferred Charges)	(5,201)
Debt Issue Costs (CGAAP)	(5,201)
Reclass to Other Assets (Deferred Charges)	4,418
Non-Regulated (effective interest method)	783
Regulated	-
Contributions in Aid of Construction	-
Reclass from Plant and Equipment	147,743
Reclass from Accumulated Depreciation	(50,072)
Regulated	97,671
Capital Lease and Finance Obligations (US GAAP)	312,395
Brilliant Power Purchase Agreement Lease	(275,959)
Trail Office Building Finance Obligation	(11,367)
Capital Lease Obligation (non-rate base) (CGAAP)	25,069
Reclass from Current	462
Regulated	25,531
Pension and Other Post-Employment Benefits (US GAAP)	80,532
Reclass Prepaid Pension Asset	5,043
Pension & OPEB Funded Status Adjustment	(63,244)
Pension & OPEB Transitional Asset	(4,157)
Reclass from Accounts Payable and Accrued Liabilities	767
Pension and Other Post-Employment Benefits (non-rate base) (CGAAP)	18,941
Other Liability	874
Reclass to Other Assets (Deferred Charges)	(874)
Regulated	-
Regulated Liability - Long-term	6,963
Non-Regulated (effective interest method)	(783)
Reclass to Other Assets (Deferred Charges)	(6,180)
Regulated	-
Deferred Income Taxes (non-rate base)	110,339
Reclass from DIT Asset	(647)
Reclass from Current DIT Liability	2,109
Walden Power Partnership DIT Liability	(1,181)
Princeton Light & Power Regulated DIT Liability	(418)
Regulated	110,202
Deferred Income Taxes	-
Princeton Light & Power Regulated DIT Liability	418
Regulated	418
Accounts Payable and Accrued Liabilities (US GAAP)	41,776
Reclass to Pension and Other Post-Employment Benefits	(767)
Accounts Payable and Accrued Liabilities (CGAAP)	41,009
Reclass to Accrued Interest	(7,338)
Intercompany Accounts	6,824
Non-Regulated	(480)
Walden Power Partnership	(111)
Regulated	39,904
Current Portion of Debt	925
Walden Power Partnership	(925)
Regulated	-
Current Portion of Capital Lease Obligation	462
Reclass to Long-term	(462)
Regulated	-
Regulated Liability - Current	1,969
Reclass to Deferred Charges	(1,969)
Regulated	-
Income Taxes Payable	260
Non-Regulated Income Tax Receivable	799
Regulated	1,059
Accrued Interest	-
Reclass from Accounts Payable	7,338
Regulated	7,338
Deferred Income Taxes - Current	2,109
Reclass to Long-term DIT Liability	(2,109)
Regulated	-

Note: Minor differences due to rounding.

Appendix G

SUMMARY 2014 TO 2018 FINANCIAL SCHEDULES

Summary 2014 to 2018
Financial Schedules

July 2013

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REVENUE REQUIREMENTS OVERVIEW

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	Sales Volume (GWh)	3,240	3,258	3,276	3,295	3,318
2	Rate Base	1,226,737	1,257,107	1,282,570	1,298,617	1,307,066
3	Return on Rate Base	7.13%	6.98%	7.01%	7.01%	7.02%
4						
5	**REVENUE DEFICIENCY**			($000s)		
6						
7	**POWER SUPPLY**					
8	Power Purchases	87,814	116,380	134,204	136,716	140,322
9	Water Fees	10,057	10,532	10,479	10,688	10,902
10		97,871	126,913	144,683	147,404	151,224
11	**OPERATING**					
12	O&M Expense	61,386	61,744	60,960	62,378	63,302
13	Capitalized Overhead	(12,277)	(12,349)	(12,192)	(12,476)	(12,660)
14	Wheeling	5,224	4,856	4,952	5,050	5,208
15	Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
16		46,751	46,621	45,939	47,198	48,030
17	**TAXES**					
18	Property Taxes	15,903	16,329	16,612	16,975	17,290
19	Income Taxes	9,241	4,738	3,896	6,818	9,544
20		25,144	21,067	20,508	23,793	26,834
21	**FINANCING**					
22	Cost of Debt	42,607	41,742	42,925	43,545	43,861
23	Cost of Equity	44,899	46,010	46,942	47,529	47,839
24	Depreciation and Amortization	57,773	56,067	58,217	60,557	62,877
25		145,279	143,819	148,085	151,631	154,576
26						
28	Flow Through Adjustments	(14,207)	-	-	-	-
29	Rate Stabilization	22,567	(2,430)	(10,112)	(7,100)	(2,925)
30		8,360	(2,430)	(10,112)	(7,100)	(2,925)
31						
32	**TOTAL REVENUE REQUIREMENT**	323,405	335,990	349,102	362,926	377,740
33						
34	**LESS: REVENUE AT APPROVED RATES**	312,923	325,111	337,798	351,194	365,502
35	**REVENUE DEFICIENCY for Rate Setting**	10,482	10,879	11,304	11,732	12,237
36						
37	**RATE INCREASE**	**3.30%**	**3.30%**	**3.30%**	**3.30%**	**3.30%**

Note: minor differences due to rounding.

SCHEDULE 1 – UTILITY RATE BASE

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
				($000s)		
1	Plant in Service, January 1	1,718,111	1,804,278	1,873,922	1,934,325	1,995,295
2	Net Additions	86,167	69,644	60,403	60,969	58,097
3	Plant in Service, December 31	1,804,278	1,873,922	1,934,325	1,995,295	2,053,392
4						
5	Add:					
6	CWIP not subject to AFUDC	7,678	8,384	8,536	7,304	7,390
7	Plant Acquisition Adjustment	11,912	11,912	11,912	11,912	11,912
8	Deferred and Preliminary Charges	(2,530)	(454)	10,047	15,868	16,602
9						
10		1,821,339	1,893,764	1,964,821	2,030,379	2,089,295
11	Less:					
12	Accumulated Depreciation					
13	and Amortization	467,919	509,998	558,319	608,697	660,838
14	Contributions in Aid of Construction	102,414	105,538	108,608	111,664	114,620
15		570,333	615,536	666,927	720,361	775,458
16						
17	Depreciated Rate Base	1,251,006	1,278,228	1,297,894	1,310,018	1,313,837
18						
19	Prior Year Depreciated Utility Rate Base	1,229,392	1,251,006	1,278,228	1,297,894	1,310,018
20						
21	Mean Depreciated Utility Rate Base	1,240,199	1,264,617	1,288,061	1,303,956	1,311,928
22	Add:					
23	Allowance for Working Capital	2,184	2,399	2,400	2,606	2,702
24	Deferred Opening Balance Adjustment	(3,801)	201	-	-	-
25	Adjustment for Capital Additions	(11,845)	(10,110)	(7,891)	(7,945)	(7,564)
26						
27	**Mid-Year Utility Rate Base**	**1,226,737**	**1,257,107**	**1,282,570**	**1,298,617**	**1,307,066**

Note: minor differences due to rounding.

SCHEDULE 2 – EARNED RETURN

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
1	SALES VOLUME (GWh)	3,240	3,258	3,276	3,295	3,318
2						
3				($000s)		
4						
5	ELECTRICITY SALES REVENUE	323,405	335,990	349,102	362,926	377,740
6						
7	EXPENSES					
8	Power Purchases	87,814	116,380	134,204	136,716	140,322
9	Water Fees	10,057	10,532	10,479	10,688	10,902
10	Wheeling	5,224	4,856	4,952	5,050	5,208
11	Net O&M Expense	49,109	49,395	48,768	49,902	50,641
12	Property Tax	15,903	16,329	16,612	16,975	17,290
13	Depreciation and Amortization	57,773	56,067	58,217	60,557	62,877
14	Other Income	(7,582)	(7,630)	(7,781)	(7,755)	(7,819)
15	Flow-Through Adjustments	(14,207)				
16	Rate Stabilization	22,567	(2,430)	(10,112)	(7,100)	(2,925)
17	UTILITY INCOME BEFORE TAX	96,747	92,490	93,763	97,892	101,243
18	Less:					
19	INCOME TAXES	9,241	4,738	3,896	6,818	9,544
20						
21	EARNED RETURN	87,506	87,752	89,867	91,074	91,699
22	RETURN ON RATE BASE					
23	Utility Rate Base	1,226,737	1,257,107	1,282,570	1,298,617	1,307,066
24	Return on Rate Base	7.13%	6.98%	7.01%	7.01%	7.02%

Note: minor differences due to rounding.

SCHEDULE 3 – INCOME TAX EXPENSE

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
				($000s)		
1	UTILITY INCOME BEFORE TAX	96,747	92,490	93,763	97,892	101,243
2	Deduct:					
3	Interest Expense	42,607	41,742	42,925	43,545	43,861
4						
5	ACCOUNTING INCOME	54,139	50,749	50,838	54,348	57,382
6						
7	Deductions					
8	Capital Cost Allowance	67,932	72,036	70,987	68,606	67,010
9	Capitalized Overhead	12,277	12,349	12,192	12,476	12,660
10						
11	Incentive & Revenue Deferrals	(8,360)	2,430	10,112	7,100	2,925
12	Financing Fees	707	558	881	881	563
13	Pension Contribution	10,586	10,804	9,019	7,561	6,922
14	Other Post Employment Benefit (OPEB) Contribution	721	788	860	934	1,014
15	All Other (net effect)	885	916	894	827	834
16		84,749	99,881	104,945	98,384	91,929
17						
18	Additions					
19	Amortization of Deferred Charges	6,888	3,535	3,280	3,492	3,659
20	Pension Expenses	8,342	7,379	6,407	5,559	4,833
21	Other Post Employment Benefit (OPEB) Expenses	3,958	4,067	4,185	4,312	4,448
22	Depreciation	50,886	52,532	54,938	57,065	59,219
23		70,073	67,513	68,809	70,428	72,158
24						
25	TAXABLE INCOME	39,464	18,380	14,702	26,392	37,612
26						
27	Tax Rate	25.0%	25.0%	25.0%	25.0%	25.0%
28						
29	Taxes Payable	9,866	4,595	3,676	6,598	9,403
30	Prior Years' Overprovisions/(Underprovisions)	(805)	-	-	-	-
31	Deferred Charges Tax Effect	180	143	220	220	141
32						
33	**REGULATORY TAX PROVISION**	9,241	4,738	3,896	6,818	9,544

Note: minor differences due to rounding.

SCHEDULE 4 – COMMON EQUITY

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
				($000s)		
1	Share Capital	180,122	195,122	195,122	195,122	195,122
2	Retained Earnings	294,496	311,395	317,405	324,347	331,876
3						
4	COMMON EQUITY - OPENING BALANCE	474,618	506,517	512,527	519,469	526,998
5						
6	Less: Common Dividends	(28,000)	(40,000)	(40,000)	(40,000)	(45,000)
7						
8	Add: Net Income	44,899	46,010	46,942	47,529	47,839
9	Shares Issued	15,000	-	-	-	-
10						
11	COMMON EQUITY - CLOSING BALANCE	506,517	512,527	519,469	526,998	529,837
12						
13	SIMPLE AVERAGE	490,568	509,522	515,998	523,234	528,418
14						
15	Adjustment for Shares Issued	3,842	-	-	-	-
16	Deemed Equity Adjustment	(3,715)	(6,679)	(2,970)	(3,787)	(5,592)
17						
18	COMMON EQUITY - AVERAGE	490,695	502,843	513,028	519,447	522,826

Note: minor differences due to rounding.

SCHEDULE 5 – RETURN ON CAPITAL

		Forecast 2014	Forecast 2015	Forecast 2016	Forecast 2017	Forecast 2018
				($000s)		
1	Secured and Senior Unsecured Debt	736,658	690,000	747,671	765,000	765,000
2	Proportion	60.05%	54.89%	58.29%	58.91%	58.53%
3	Embedded Cost	5.69%	5.62%	5.51%	5.50%	5.50%
4	Cost Component	3.42%	3.08%	3.21%	3.24%	3.22%
5	Return	41,952	38,758	41,213	42,065	42,065
6						
7	Short Term Debt	(616)	64,264	21,871	14,170	19,240
8	Proportion	-0.05%	5.11%	1.71%	1.09%	1.47%
9	Embedded Cost	-106.41%	4.64%	7.83%	10.44%	9.33%
10	Cost Component	0.05%	0.24%	0.13%	0.11%	0.14%
11	Return (including fees)	655	2,984	1,713	1,480	1,796
12						
13	Common Equity	490,695	502,843	513,028	519,447	522,826
14	Proportion	40.00%	40.00%	40.00%	40.00%	40.00%
15	Embedded Cost	9.15%	9.15%	9.15%	9.15%	9.15%
16	Cost Component	3.66%	3.66%	3.66%	3.66%	3.66%
17	Return	44,899	46,010	46,942	47,529	47,839
18						
19	TOTAL CAPITALIZATION	1,226,737	1,257,107	1,282,570	1,298,617	1,307,066
20	RATE BASE	1,226,737	1,257,107	1,282,570	1,298,617	1,307,066
21						
22	Earned Return	87,506	87,752	89,867	91,074	91,699
23						
24	RETURN ON CAPITAL	7.13%	6.98%	7.01%	7.01%	7.02%
25	RETURN ON RATE BASE	7.13%	6.98%	7.01%	7.01%	7.02%

Note: minor differences due to rounding.

Appendix H

DEMAND SIDE MANAGEMENT

FORTIS BC™

Demand Side Management

July 2013

Table of Contents

1. INTRODUCTION

This Appendix outlines FBC's request pursuant to section 44.2 of the *Utilities Commission Act* (UCA) for acceptance of Demand-Side Management (DSM) expenditures for the period from 2014 to 2018. The funding request outlined in this Appendix is supported by the 2014-2018 DSM Plan (DSM Plan), which is found in Attachment H1. The DSM Plan provides details on each of the FBC program areas and individual DSM programs, including cost-effectiveness test results. The DSM funding request is also supported by the FBC 2012 Semi-Annual DSM Year-End Report included as Attachment H2. The Annual Report describes the results of FBC's 2012 PowerSense programs, many of which FBC is proposing to continue. In sum, FBC's evidence in this Application demonstrates that the proposed DSM expenditures are cost effective and in the public interest.

The 2014-2018 DSM expenditure filing reflects a marked reduction in the Long Run Marginal Cost (LRMC) (see Section 2.3), which is used in the Total Resource Cost (TRC) Benefit/Cost evaluation of DSM measures and programs. Fewer measures, and in some cases programs, are now cost-effective as defined by the Demand-Side Measures Regulation[1] (the DSM Regulation). The result is a reduced DSM expenditure request for the 2014-2018 filing period as compared to the 2012-13 approved Plan. The lower program expenditure level will result in lower average customer rates over the test period by between 0.3 percent and 0.5 percent annually, and approximately 1.6 percent over the 2014 – 2018 PBR period, compared to continuing at the approximate level of expenditures previously approved.

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: DSM Plan and Funding Request

[1] Demand-Side Measures Regulation 326/2008 [includes B.C. Reg. 228/2011 amendments (effective Dec. 8, 2011)]

Attachments:

2. BACKGROUND

2.1 *LEGAL FRAMEWORK*

FBC is filing the DSM expenditure 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 DSM Plan, all proposed activity qualifies as "demand side measures" as defined under the *Clean Energy Act* (CEA)[2]. 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 all (or a part of) the expenditure schedule if it considers the schedule, or a part of it, to be in the public interest. . 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 applicability 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.

The first two considerations are addressed in following sections. The consideration of “adequacy”, as defined in the Demand Side Measures Regulation (DSM Regulation), is discussed in Section 2.4 below. The consideration of cost-effectiveness of the expenditure schedule is addressed in Section 6.1 farther on.

2.2 CONSISTENCY WITH BRITISH COLUMBIA ENERGY OBJECTIVES

British Columbia’s energy objectives are defined and set out in section 2 of the CEA. The applicable energy objectives and how FBC’s proposals support those objectives are set out in the table below.

Table H-1: BC’s Energy Objectives Met by FBC DSM Activity

Energy Objective	FBC DSM Portfolio
(b) to take demand-side measures and to conserve energy…	FBC’s DSM proposals are designed to implement cost-effective (as defined by the DSM Regulation) demand-side measures.
(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;	FBC supports pilot projects of new DSM technologies, and the DSM Plan allows new measures to be incented if B/C ratio is positive.

[2] Clean Energy Act [SBC 2010] Chapter 22 Definitions 1. (1)

Energy Objective	FBC DSM Portfolio
(h) to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;	FBC does not have a fuel switching program at this time.
(i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;	The Rossland Energy Diet was a pilot in community energy engagement, that has been expanded to the regionally-based Kootenay Energy Diet.

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 2012 LTRP submitted in June of 2011.[3] The 2014-2018 DSM Plan and the proposed expenditures are consistent with the methodology used in the 2012 LTRP, and the Commission's directives[4] regarding the plan.

The 2012 LTRP and the associated 2012 Long Term DSM Plan[5] were predicated on a levelized market price of $84.94/MWh. Since then, the Company has determined the LRMC has declined to $56.61/MWh (see attachment H4). The number and breadth of DSM measures and programs that pass the Total Resource Cost test, has diminished commensurate with the lower LRMC. The current LRMC, coupled with other non-program conservation drivers, e.g. Residential Conservation Rate, resulted in the 2014-2018 DSM Funding Request that follows in Section 5.1.

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) 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; and

d) an education program for students enrolled in post-secondary institutions in the public utility's service area.

[3] FortisBC 2012 Integrated System Plan Volume 2
[4] BCUC Order G-110-12.
[5] FortisBC 2012 Integrated System Plan Volume 2

The Company addresses each of these adequacy provisions below. More details on each program will be found in the DSM Plan.

2.4.1 Low Income Programs

The Low Income Program is specifically designed to meet the needs of the Company's low income customers, in collaboration with the FEU[6] and BC Hydro and Power Authority (BCH or BC Hydro), that are of no cost or low cost to low income participants.

The Low Income Program portfolio includes Energy Saving Kit (ESK), direct-install lighting measures, and the new Energy Conservation Assistance Program (ECAP). Continued investment in this Program Area is planned moving forward.

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 Commercial Lighting offers, the Building Improvements Program (New and Retrofit), WaterSavers (low-flow showerheads) and the Commercial Energy Assessment Program.

2.4.3 Education Programs

FBC, in collaboration with FEU, funds a variety of education programs for K-12 students enrolled in schools in its service area 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.

There are also a number of initiatives specifically targeting post-secondary students, encouraging them to learn and apply their knowledge of energy conservation through interactive and fun competitions.

[6] Comprised of FortisBC Energy Inc., FortisBC Energy Inc. Fort Nelson Service Area, FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc.

3. RESPONSE TO COMMISSION DIRECTIVES

The Company believes it has met the directives listed in the 2012-2013 RRA Decision in Order G-110-12. Table H-2 below addresses each of the directives related to DSM and briefly describes how the Company has complied with these directives including, references to where further information on this compliance can be found.

Table H-2: FBC Meets Commission Directives

Directive Reference (s)	Commission Directives to FBC	Compliance Undertaken	Response Reference (s)
Directive 47, 2012-13 RRA Decision	The Commission Panel rejects FortisBC's proposed M&E Plan in its current form as it fails to ensure that all programs are evaluated.	A new M&E Plan has been written and is filed as part of this RRA	Section 7.1 and Attachment H3 of this application.
Directive 50, 2012-13 RRA Decision	The Commission Panel therefore approves FortisBC's transfer of a maximum of 25 per cent of the budget amount from one existing program area or sector to another existing program area or sector without prior approval of the Commission.	Approval obtained (post) for the 2012 Residential underspend and the Commercial overspend.	BCUC Order G-110-12.
Directive 51, 2012-13 RRA Decision	The Commission Panel directs FortisBC to include in its semi-annual DSM reports and in future DSM filings with the Commission, a short summary of progress on integration among utilities.	Said reports now include an integration status report.	Attachment H2: 2012 Semi-Annual DSM Report s4 (p3).

4. HISTORICAL EXPENDITURE LEVELS

For historical reference, Table H-3 shows the planned and actual DSM expenditures since 2008, the year in which the Commission granted the Company approval to increase DSM activity. The 2012 Semi-Annual DSM Report provided in Attachment H2 shows (as do prior annual reports) that DSM spending in each of these years has been cost effective.

Table H-3: Plan and Actual DSM Expenditures Since 2008

DSM Expenditures since 2008

2008		2009		2010		2011		2012	
Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual
2,355	2,683	3,667	3,464	3,952	3,712	7,842	5,907	7,731	7,300

5. DSM PLAN AND FUNDING REQUEST

The DSM Plan covers the DSM funding request for 2014-2018 for FBC for previously approved Sectors and Program Areas: Residential (including Low Income), Commercial, Supporting Initiatives, Planning and Evaluation, and Industrial.

A five year funding approval is being requested in order to establish certainty in the market that FBC will be able to offer the programs listed in the DSM Plan over an extended period. This will allow external parties such as contractors, manufacturers and other program partners to better support DSM initiatives knowing that they will be established for the long term. It will also enable FBC to take advantage of program momentum and it will spare DSM resources from extensive regulatory work so they can dedicate their time to program development and operation.

Many of the programs in this DSM Plan are continuations of previously-approved programs that FBC is currently running, and has reported on in its previous Semi-Annual DSM Reports. The DSM Plan provides program details and projected cost-effectiveness results for the FBC's proposed portfolio of DSM Program Area activity for 2014 – 2018.

5.1 *FUNDING REQUEST BY PROGRAM AREA*

FBC's 2012 Actual, 2013 Approved and the 2014 Plan expenditures in each of the Sectors or Program Areas are outlined in the table below:

Table H-4: FBC DSM Expenditures - 2012 Actual, 2013 Approved and 2014 Plan

Program Area	2012 Actual		2013 Approved		2014 Plan		TRC	TRC incl mTRC
	Savings	Cost	Savings	Cost	Savings	Cost		
Programs by Sector	*MWh*	$(000s)	*MWh*	$(000s)	*MWh*	$(000s)	B/C ratio	
Residential	12,757	2,564	16,946	3,944	5,800	1,037	1.2	1.3
General Service	17,892	3,020	11,980	2,085	6,200	1,134	1.4	1.7
Industrial	937	173	2,580	364	800	148	2.8	2.8
Sub-total Programs:	**31,586**	**5,757**	**31,506**	**6,393**	**12,800**	**2,319**	**1.4**	**1.5**
Supporting Initiatives		816		725		190		
Planning & Evaluation		728		760		492		
Total (incl. Portfolio spend):		7,300		7,878		3,001	**1.2**	**1.4**

The 2015 through 2018 plan years are patterned on the 2014 Plan. Details for the years 2014–2018 are found in the DSM Plan.

5.2 *PREVIOUSLY APPROVED PROGRAMS*

The programs listed in the 2014 DSM Plan are largely continuations of existing programs that were approved in the 2012-13 RRA and accepted as part of 2012 ISP filing. Table H-5 lists all of the programs in the DSM Plan categorized as "Approved for 2012-2013", even if modified in some form. Further details, descriptions and approximate timelines for each program listed in Table H-5 can be found in the DSM Plan

Table H-5: Programs Classified as Previously Approved or New

Program Area	DSM Plan 2014 - 2018 Programs	Approved for 2012-2013
Residential	Home Improvement (Building Envelope) Program	X
	Heat Pump Program	X
	ENERGY STAR® Water Heater Program	X
	Water Savers (Low-Flow Fixtures)	X
	ENERGY STAR® Residential Lighting	X
	New Home Program	X
	Financing Pilot	X
Commercial	Commercial Lighting Program	X
	Building & Process Improvement Program	X
	Product Rebate Program	X
	Commercial Energy Assessment Program	X
Industrial	Industrial Efficiency Program	X
Low Income	Energy Savings Kit	X
	Energy Conservation Assistance Program	X
	Direct Install Lighting	X
Conservation Education & Outreach	Public Awareness Program	X
	School Education Program	X

5.3 *PLAN FLEXIBILITY AND ADJUSTMENT*

This DSM 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 Company operates. Due to the length of the period the DSM Plan covers, FBC requires the 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 Company proposes that program funding transfer rules follow the same process as was directed by the Commission for the 2012-13 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 per cent 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 per cent 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 per cent of that approved Program Area, prior Commission approval would be required.

In addition, the Company proposes that it 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, benefit/cost test requirements, and has not been previously rejected by the Commission.

This new funding transfer rule will allow the FBC 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. FBC will continue to comply with all cost-effectiveness tests, reporting and other requirements for these new programs.

5.4 *DSM GUIDING PRINCIPLES*

The 2012 DSM Plan was created using the following guiding principles:

1. The DSM Plan will be customer focused by offering a range of measure choices within programs that address the key end-uses of the principal customer rate classes;
2. The DSM Plan will be cost effective by including only those measures, with the exception of prescribed measures, which have a TRC Benefit Cost ratio greater than unity on a portfolio basis;
3. The DSM Plan will be inclusive of best practices in terms of program design, implementation, marketing, outreach, monitoring and evaluation; and
4. The DSM Plan will be compliant with the applicable sections of the UCA and CEA including DSM Regulations thereunder.

FBC continues to be guided by these principles in designing and carrying out the 2014-2018 DSM Plan.

6. COST EFFECTIVENESS APPROACH

6.1 *COST-EFFECTIVENESS UNDER THE DEMAND-SIDE MEASURES REGULATION*

FBC's proposed DSM portfolio for the 2014-18 funding period is cost-effective according to the currently approved approach to determining cost-effectiveness. As shown in the DSM Plan, 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 DSM Plan also meets the requirements of the provincial DSM Regulation. FBC submits that the current approach to determining the cost-effectiveness of its DSM programs is comprehensive, benefits customers and should be carried forward through the 2014-18 PBR period.

The relevant parameters set out in the DSM Regulation are summarized below. Other considerations for determining the cost-effectiveness of the Company's 2014-18 DSM Plan are covered in the remainder of Section 6 below.

6.1.1 Portfolio-Level Analysis

Section 4(1) of the DSM 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. FBC maintains that portfolio-level analysis remains the appropriate level of cost-effectiveness testing.

In its Decision on the FBC's 2012-13 RRA[7] the Commission approved the assessment of cost-effectiveness on an overall portfolio basis, as long as the DSM portfolio meets a combined TRC/MTRC of unity (1.0) or greater. There are several reasons to continue with the portfolio approach going forward:

- According to Sections 4(4) and 4(5) of the DSM Regulation, the Commission must, at a minimum, use the portfolio approach in assessing the cost effectiveness of "specified demand-side measures"[8] and "public awareness programs".[9]
- A portfolio approach to cost-effectiveness analysis promotes FBC's goal of making DSM accessible to all customers. Residential programs often have difficulty passing the 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

[7] Decision and Order G-44-12 p. 174. .

[8] "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.

[9] 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 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.

portfolio approach might result in fewer DSM programs being available to residential and low-income customers.

For these reasons, the currently-approved portfolio approach remains appropriate for determining the cost effectiveness of DSM activities. For information purposes, FBC will continue to report on individual DSM program cost-effectiveness results in its Annual Reports, and individual program cost-effectiveness projections are also provided in the 2014-2018 DSM Plan.

6.1.2 Total Resource Cost (TRC) Test

The TRC "Test" is generally expressed as a ratio of the Benefits of a DSM Measure divided by the Measure's cost, including the utility's program costs. The Benefits, also known as "avoided costs", are primarily the present value of the Measure's energy savings, over its effective life, valued at the LRMC levelized price (see Attachment H4).

According to Section 4(2) of the DSM 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 modified TRC (MTRC) test (see Section 6.1.3). 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. The DSM Regulation also includes special consideration for specified measures (Section 4(4)) and low income programs (Section 4(2)).

The cost-effectiveness of a specified DSM 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.[10] FBC has included specified demand-side measures within its Residential and Supporting Initiatives Program Areas.

A DSM intended specifically to assist residents of low-income households to reduce their energy consumption (which would include the activities within the FBC's Low Income Program) the Commission must use, "in addition to any other analysis the Commission considers appropriate," the TRC test and consider the benefit of the DSM to be 130 percent of its value. FBC has applied this approach in the cost-effectiveness analysis of the Low Income programs presented in the 2014-2018 DSM Plan.

6.1.3 Modified Total Resource Cost Test

Amendments to the DSM Regulation in 2011 included the addition of subsection 4(1.1) allowing for the use of the MTRC for up to 10 per cent of the electricity DSM portfolio, excluding specified demand-side measures. FBC manages its activities to stay within this MTRC Cap. The MTRC includes two key components: the use of a BC "clean" new resource in determining avoided

[10] For a more detailed description of specified demand-side measures see Section 1 of the British Columbia Demand-Side Measures Regulation.

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 BC Clean resources

For the purposes of calculating the MTRC, the DSM Regulation states:

> *s4(1.1)(b) subject to subsection (1.3), the avoided electricity cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is*
>
> *(i) in the case of a demand-side measure of FortisBC Inc., an amount that the commission is satisfied represents FortisBC Inc.'s long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia*

In the 2012-13 RRA filing this value was defined as BC Hydro's long run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia. At the time the value used in the MTRC calculation was $112/MWh. 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 Semi-Annual Year-end DSM Report.

6.1.3.2 Inclusion of Non-Energy Benefits (NEBs)

Section 4(1.1)(c) of the DSM 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 per cent adder to the benefits side of the MTRC calculation. FBC uses the 15 per cent NEB adder in its MTRC calculations for the DSM Plan.

6.2 *ELEMENTS OF THE STANDARD COST BENEFIT TESTS*

While the TRC and MTRC continue to be the cost-effectiveness tests that FBC is putting forward for determining the portfolio cost-effectiveness, the Company has also historically reported on a range of other standard cost-effectiveness tests used by the industry. The standard cost-effectiveness tests are the TRC, the Ratepayer Impact Measure (RIM), the Utility Cost Test (UCT)[11] and the Participant Cost Test (PCT) calculations at the program, Program Area (or sector) 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.

[11] Referred to as Program Administrator Cost Test in the California Manual

6.2.1 Net-to-Gross (NTG) Ratio: Spill-over[12] and Free Riders

Historically, the way in which the FBC calculated NTG 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. Additionally FBC has included “spill-over” effects, where known, in the NTG which is a recognized approach that is used by other utilities including BC Hydro.[13] As “spill-over” is the conceptual opposite of “free riders”, including both effects presents a more complete and balanced view of program impacts.

FBC intends to continue evaluating and quantifying spill-over effects on a program-by-program basis. Where adequate estimates are developed or acquired based on the results of an evaluation, free rider and spill-over effects would be accounted for in the NTG ratio as appropriate.

6.2.2 Attribution of Savings from the Introduction of Regulation

According to Section 4(1.4) of the DSM 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 DSM 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 FBC’s proposed portfolio outlined in the DSM 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 Company intends 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. FBC is seeking the Commission’s endorsement of the concept for reporting purposes. It is the intent of FBC 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 DSM Annual Report.

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[12] Spillover effects involve non-participants who acquired an energy conservation measure (ECM), and who did not receive an incentive, but were influenced by the operation of the utility’s DSM program

[13] 2012-2013 RRA Exhibit B-9, BCUC IR 1.210.2.

7. EVALUATION, MEASUREMENT & VERIFICATION

FBC considers Evaluation, Measurement and Verification (EM&V) to be an important aspect of the overall DSM program lifecycle. Over time the Company will evaluate all programs, with comprehensive, impact, process and/or market reviews at appropriate times in the program life cycles. The evaluation results will inform program design, and key reports will be shared with stakeholders and the Commission. Three key aspects of the Company's EM&V activities are addressed in the following discussion: the 2013-15 Evaluation Plan, the Company's EM&V Framework and attribution rules for claiming energy savings from multi-utility programs.

7.1 *MONITORING AND EVALUATION PLAN*

Attachment H3 contains the Company's 3 Year Evaluation Plan, covering the 2013 to 2015 period for its M&E activities, including evaluations for process, impact, and communications, as well as measurement and verification activities for its current and planned DSM programs. Overall planning & evaluation (P&E) expenditures reported in Section 5.1 include costs for EM&V activities. The total proposed expenditure for program evaluation activities to be conducted from 2013 to 2015 is approximately $815 thousand. The proposed budget aligns with the Company's EM&V Framework and industry general practice[14] for budget spending on M&E activities, representing 7.9 per cent of the Company's total DSM portfolio expenditure.

7.2 *EM&V FRAMEWORK*

The FEU, in conjunction with FBC, 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 (to FEU Companies) in their 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 Companies are finalizing the EM&V Framework in 2013, taking into consideration input from FBC, and feedback received from the Energy Efficiency and Conservation Advisory Group

[14] California Evaluation Framework. June 2004. TecMarket Works.

(EECAG) and its evaluation partners. The EM&V Framework will be updated periodically to meet any new industry standards and best practices that may be adopted from time to time.[15]

7.3 ATTRIBUTION RULES FOR MULTI-UTILITY PROGRAMS

At the direction of the BCUC in its decision on FEI's 2012-13 RRA the FEU has developed 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 attributing the savings within the respective service areas, in regards to the two public electric utilities. Only FEU, to the best of the Company's knowledge, has claimed or reported the natural gas savings and resulting emission reductions. Going forward, FBC will continue to work in developing more comprehensive attribution rules in cooperation with BC Hydro and the FEU Companies so that reporting of the benefits of combined programs is maximized while avoiding the potential for double counting of energy savings.

[15] 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 *AMORTIZATION PERIOD*

In its Special Direction to the BCUC regarding BC Hydro's 2012-14 RRA, the provincial government authorized BCH to increase its DSM amortization period to 15 years, which the BCUC approved[16].

Based on the 2014-2018 DSM Plan, the weighted average measure life is 15.9 years for all DSM programs.

Table H-6: Effective Measure Lifetime (EML) Weighted by Plan Cost

1	**Program Area**	**Plan Savings (MWh)**	**Plan Cost, $(000s)**	**EML (years)**
2		**2014 - 2018**	**2014 - 2018**	
3	**Programs by Sector**			
4	Residential	28,116	5,165	18.0
5	General Service	32,040	5,974	14.7
6	Industrial	4,000	760	9.9
7	**Total**	**64,156**	**11,899**	**15.9**
8	**Residential Programs**			
9	Building Envelope	9,405	1,508	25
10	Heat Pumps	2,765	805	20
11	Lighting	9,987	822	12
12	New Home	490	342	30
15	Water heating	2,275	541	11
16	Low Income & Rental	3,194	1,147	12
18	**Total**	**28,116**	**5,165**	**18.0**
19	**General Service Programs**			
20	Lighting	17,835	2,784	11
21	BIP	13,205	3,025	18
24	Irrigation	1,000	165	10
25	**Total**	**32,040**	**5,974**	**14.7**
26	**Industrial Programs**			
28	Ind Efficiency	4,000	760	10
29	**Total**	**4,000**	**760**	**9.9**

16 Order G-77-12A, page 4:
(vi) A change in the amortization period from 10 to 15 years effective April 1, 2011, for all past and future DSM expenditures included in the DSM regulatory account is approved.

FBC seeks approval to increase its DSM amortization period from ten to fifteen years to follow suit with BC Hydro. A longer amortization period results in steady and manageable rate increases for customers and provides FBC with the opportunity to continue requesting DSM funding envelopes that adequately support customer energy efficiency needs.

8.2 REQUEST FOR CHANGE IN DSM REPORTING PERIOD

FBC currently files semi-annual reports on its DSM activities, a reporting schedule which is inconsistent with the reporting requirements for other BC utilities, including the FEU and BC Hydro, and which is administratively burdensome. FBC therefore proposes to submit DSM reports on an annual, year-end, basis, consistent with the FEU and BC Hydro.

Attachment H1

2014-2018 DEMAND SIDE MANAGEMENT (DSM) PLAN

2014-2018 Demand Side Management (DSM) Plan

June 21, 2013

FortisBC Inc.

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1. DEMAND SIDE MANAGEMENT

Demand Side Management (DSM) or energy efficiency programs have been offered to FBC customers since 1989 and are available to all customers served by FBC and its wholesale customers of Grand Forks, Nelson Hydro, Penticton, and Summerland.

The 2014-18 DSM Plan is a modified extension of the 2012-13 DSM Plan, which received approval via Commission Order G-110-12. The 2014-18 DSM Plan programs, and expenditures, are reduced commensurate with the advent of the lower Long Run Marginal Cost (LRMC) of $56.61/MWh. The LRMC affects the Total Resource Cost test by reducing the benefit of power purchase reductions, which in turn makes fewer demand-side management programs and measures economic as prescribed by the Demand-Side Measures Regulation (DSM Regulation).

Planned DSM expenditures are $3.0 million in 2014 with modest escalation in the subsequent years 2015-18 inclusive. The 2013 approved DSM expenditure was $7.8 million nominal (before tax effect). All figures in the DSM Plan are nominal..

The 2014-18 DSM plan portfolio includes programs for the residential, commercial, industrial and irrigation customer classes and is intended to capture economic potential savings over the long term, as identified in the 2013 CPR update. There are also portfolio-level expenditures for supporting initiatives, and planning and evaluation.

The 2014-18 DSM Plan was also developed in the context of the DSM Regulation, as discussed in Appendix H. It includes programs that are mandated to meet the adequacy provisions of the 2011 DSM Regulation, namely measures for rental and low income customers, education (elementary and secondary) and post-secondary schools .

Table H1-1 below is a summary table of the proposed 2014-18 DSM energy savings, expenditures by sector, portfolio level and totals (gross and net of tax), and the Total Resource Cost (TRC) Benefit/Cost ratios for 2014-18 by program sector and overall.

Table H1-1a: 2014-18 DSM Plan Expenditures

Program Area	2014 Plan Cost	2014 TRC	2014 TRC incl mTRC	2015 Plan Cost	2016 Plan Cost	2017 Plan Cost	2018 Plan Cost
		B/C	B/C				
Programs by Sector	$(000s)	ratio	ratio	$(000s)	$(000s)	$(000s)	$(000s)
Residential	1,037	1.2	1.3	1,081	1,008	1,015	1,024
General Service	1,134	1.4	1.7	1,166	1,195	1,223	1,256
Industrial	148	2.8	2.8	150	152	154	156
Sub-total Programs:	**2,319**	**1.4**	**1.5**	**2,397**	**2,355**	**2,392**	**2,436**
Supporting Initiatives	190			190	190	190	190
Planning & Evaluation	492	-	-	500	509	518	527
Total (incl. Portfolio spend):	3,001	**1.2**	**1.4**	3,087	3,054	3,100	3,153

Note: the alternative Benefit/Cost ratios (UCT, RIM, PCT) by program, sector and portfolio are shown in the Summary Table H1-7 at the end of the 2014-18 DSM Plan.

Table H1-1b: 2014-18 DSM Plan Savings

Program Area	2014 Plan Savings	2015 Plan Savings	2016 Plan Savings	2017 Plan Savings	2018 Plan Savings
Programs by Sector	*MWh*	*MWh*	*MWh*	*MWh*	*MWh*
Residential	5,800	5,783	5,615	5,511	5,407
General Service	6,200	6,304	6,408	6,512	6,616
Industrial	800	800	800	800	800
Total Programs:	**12,800**	**12,887**	**12,823**	**12,823**	**12,823**

1.1 RESIDENTIAL SECTOR PROGRAMS

The DSM Plan focuses on the opportunities in residential energy retrofits, addressing major end-uses (space heating, hot water and lighting) where the majority of economic potential resides. The following tables outline the list of residential programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each incentive program and the primary delivery mechanisms follows the Tables.

Table H1-2a: Residential Program Expenditures

Program	2014			2015	2016	2017	2018
	Plan Cost	TRC	TRC incl mTRC	Plan Cost	Plan Cost	Plan Cost	Plan Cost
	$(000s)	B/C ratio		$(000s)	$(000s)	$(000s)	$(000s)
Building Envelope	295	1.1	1.3	299	301	305	308
Heat Pumps	158	1.1	1.1	159	161	163	164
Lighting	176	1.4	1.4	171	164	158	153
New Home	67	0.6	1.2	68	68	69	70
Water heating	99	1.6	1.9	103	108	112	119
Low Income & Rental	242	0.8	0.8	281	206	208	210
Residential sub-Total	**$ 1,037**	**1.2**	**1.3**	**$ 1,081**	**$ 1,008**	**$ 1,015**	**$ 1,024**

Table H1-2b: Residential Program Savings

Program	2014	2015	2016	2017	2018
	Plan Savings	Plan	Plan	Plan	Plan
	MWh	*MWh*	*MWh*	*MWh*	*MWh*
Building Envelope	1,881	1,881	1,881	1,881	1,881
Heat Pumps	553	553	553	553	553
Lighting	2,136	2,067	1,997	1,928	1,859
New Home	98	98	98	98	98
Water heating	425	440	455	470	485
Low Income & Rental	707	744	631	581	531
Residential sub-Total:	**5,800**	**5,783**	**5,615**	**5,511**	**5,407**

1.1.1 Building Envelope

The major component of the Home Improvement Program (HIP) is building envelope improvements (insulation and air sealing). Program delivery will be primarily through partnerships with utility partnerships, encouraging customers to obtain an EnerGuide energy assessment, and will focus on a “whole house” approach. Individual components of the program like heat pumps and Energy Star appliances and lighting may also be marketed separately, as described below.

Complementary to the monetary rebates offered, the On-Bill Financing (OBF) pilot continues in the South Okanagan until November 2014, and commences in Kelowna in January 2014. Elsewhere the Company has arranged low cost, off-bill financing through regional credit unions for the Kootenay Energy Diet.

1.1.2 Heat Pump Program

With its temperate winters and hot summers, the FBC service area is an ideal climate for energy efficient heat pumps. The program will continue with incentives for owners to upgrade electric heating systems to air source heat pumps. As an alternative to a direct financial incentives, FBC will also provide low-interest loans for qualifying customers at a below market interest rate (4.9 percent).

To ensure customers continue to attain high efficiencies from their heat pump technology, a heat pump tune-up promotion will continue.

1.1.3 Residential Lighting Program

It is estimated that 21 percent of all electrical use within the FBC service area is attributed to lighting. To help build market transformation and improve customer participation in lighting incentive programs, FBC will continue its partnership with BC Hydro and retailers to provide “instant rebates” at the point of purchase. Rebates will be provided for speciality Energy Star rated CFLs, LED lamps and hard-wired luminaires.

1.1.4 New Home Program

To encourage whole home energy efficiency via performance path, the ENERGY STAR® label for houses, built to 15 percent better than the BC building code, will be promoted. Energy Star rated appliances and lighting are integral requirements to qualifying for the Energy Star designation.

To further promote new home ratings, FBC will offer incentives for energy evaluations. Incentives for the most efficient heating and cooling technologies (heat pumps) will continue to be offered as a product option.

1.1.5 Water Heating

Approximately 50 percent of FBC customers’ water is heated with electricity. To encourage efficient water heating, FBC will continue to offer rebates for the installation of heat pump water heaters for customers with electrically heated water. Low flow showerheads will be distributed via Energy Saving Kits and other channels.

1.1.6 Low-Income Households Program

FBC will continue to provide low income households with Energy Saving Kits and distribute them directly to qualified customers, primarily through low-income service providers like food banks and low-income housing groups. Other complementary funding sources, e.g. provincial government, will be accessed where available to cover enabling costs, e.g. installation allowances.

In collaboration with BC Hydro (BCH) and the FortisBC Energy Utilities (FEU), FBC will provide a direct installation program which includes the basic and some extended energy conservation measures. The Energy Conservation Assistance Program (ECAP) will employ screening tools to determine which measures are appropriate and cost effective for each application. It is expected the measures will primarily be insulation of ceilings, basements and draft-proofing, as well as ENERGY STAR® lighting products. Energy Star bathroom fan(s) may be installed to address ventilation concerns.

A direct-install lighting program will be continued for common area lighting, such as corridors, stairwells, and lobbies, as well as supplying ENERGY STAR® screw-in lighting products for in-suite installation.

1.1.7 Rental Accommodation Programs

The Commercial Lighting and Building Improvement Program (BIP) is available to property managers and rental agencies to upgrade rental properties. Walk-through audits or 3rd party Energy Assessments for MURB (multi-unit residential buildings) will be offered in collaboration with FEU. Cost effective measures, such as insulation, heating equipment, and energy efficient lighting will be identified and incentives offered through the aforementioned programs.

Energy Savings Kits will be provided to qualified low-income renters.

1.1.8 Residential Behavioural Program

PowerSense messaging to encourage customers in adopting energy-efficient behaviours, (for example, the use of clotheslines) will continue using economic channels.

1.2 *COMMERCIAL SECTOR PROGRAMS*

Program offers for the Commercial sector will be focused on the economic opportunities in Commercial Lighting and Building Improvement Program. .

The following table outlines the list of commercial programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each program and the primary delivery mechanisms follows.

Table H1-3a: Commercial Program Expenditures

Program	2014 Plan Cost	2014 TRC	2014 TRC incl mTRC	2015 Plan Cost	2016 Plan Cost	2017 Plan Cost	2018 Plan Cost
	$(000s)	B/C ratio		$(000s)	$(000s)	$(000s)	$(000s)
Lighting	510	1.7	2.0	535	557	579	603
BIP	592	1.1	1.5	598	605	611	619
Irrigation	32	2.1	2.1	33	33	33	34
Commercial sub-Total	**$ 1,134**	**1.4**	**1.7**	**$ 1,166**	**$ 1,195**	**$ 1,223**	**$ 1,256**

Table H1-3b: Commercial Program Savings

Program	2014 Plan Savings	2015 Plan	2016 Plan	2017 Plan	2018 Plan
	MWh	*MWh*	*MWh*	*MWh*	*MWh*
Lighting	3,359	3,463	3,567	3,671	3,775
BIP	2,641	2,641	2,641	2,641	2,641
Irrigation	200	200	200	200	200
Commercial sub-Total	**6,200**	**6,304**	**6,408**	**6,512**	**6,616**

1.2.1 Commercial Lighting

Incentives for lighting measures are varied, with the rebate limited to achieving a two-year payback on incremental cost. Most lighting incentives will be applied either through point-of-purchase through product rebates at authorized lighting wholesalers or through the Product Rebate portal. For specialty lighting, and larger complex retrofits, customers will be encouraged to contact PowerSense directly for a custom option rebate.

1.2.2 Building Improvement Program

Program assistance and financial incentives include a free assessment of the building and where a more detailed assessment is required, 50 percent of the cost of an approved study. FBC also will provide rebates towards the incremental cost of efficiency measures compared to standard “baseline” construction. The baseline for New Construction BIP is ASHRAE 90.1 as adopted by the provincial building code. The rebate amount is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost.

In addition, FBC will offer a suite of standardized fixed rebates for the most common heating, ventilation and air conditioning measures, pumps and motors, compressed air and refrigeration technologies through the Product Rebate portal.

1.2.3 Partners in Efficiency

FBC will continue to offer a “Partners in Efficiency” initiative for local governments and larger key account customers. In addition to the incentives offered in the form of rebates and energy assessments, PowerSense representatives will work closely with the qualifying customers to help determine the economics for energy efficiency upgrades to new and existing facilities, and street lighting.

1.2.4 Irrigation

Free walk-through audits, or third-party energy assessments, will be available to qualifying irrigation customers.

Product rebate incentives on energy-efficient irrigation system components (variable-speed drives, pumps etc.) will be offered through the Product Rebate portal.

1.3 *INDUSTRIAL SECTOR PROGRAMS*

The following tables outline the proposed industrial program, plan costs and savings, and the Benefit/Cost ratio on a TRC basis. A description of the Industrial Efficiency program and the primary delivery mechanisms follows.

Table H1-4a: Industrial Efficiency Expenditures

Program	2014			2015	2016	2017	2018
	Plan Cost	TRC	TRC incl mTRC	Plan Cost	Plan Cost	Plan Cost	Plan Cost
	$(000s)	B/C ratio		$(000s)	$(000s)	$(000s)	$(000s)
Ind Efficiency	148	2.8	2.8	150	152	154	156
Industrial sub-Total	**$ 148**	**2.8**	**2.8**	**$ 150**	**$ 152**	**$ 154**	**$ 156**

Table H1-4b: Industrial Efficiency Savings

Program	2014	2015	2016	2017	2018
	Plan Savings	Plan	Plan	Plan	Plan
	MWh	*MWh*	*MWh*	*MWh*	*MWh*
Ind Efficiency	800	800	800	800	800
Industrial sub-Total	**800**	**800**	**800**	**800**	**800**

1.3.1 Industrial Efficiency

FBC will continue to offer customized assistance and financial incentives for industrial customers to achieve increased efficiency. This will include free initial assessment of energy use, and where a more detailed assessment is required, 50 percent of an approved study’s costs. FBC also will provide rebates towards the incremental cost of efficiency measures compared to “baseline” technology (the rebate amount is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost per Schedule 90 of the FBC electric tariff).

Standardized product offers (for example, variable-speed air compressors) will be offered through the product rebate web portal.

1.4 *SUPPORTING INITIATIVES*

Supporting initiatives are important for the success of the DSM Plan because they provide the program support, educate (customers and students), build trade ally capacity and promote market transformations which are necessary to enable the potential savings that have been identified. The supporting initiatives, which complement the incentive-based programs listed beforehand, are characterized as portfolio level spending since they do not result in direct DSM savings.

The Tables H1-5 lists the components and plan expenditures for the 2014-18 budget years.

Table H1-5: Supporting Initiative Expenditures

Component	2014 Plan $(000s)	2015 Plan $(000s)	2016 Plan $(000s)	2017 Plan $(000s)	2018 Plan $(000s)
Public Awareness	100	100	100	100	100
Community Energy Planning	20	20	20	20	20
Trades Training	10	10	10	10	10
Education (schools)	50	50	50	50	50
Codes and Standards	10	10	10	10	10
Supporting Initiatives sub-Total	**$ 190**	**$ 190**	**$ 190**	**$ 190**	**$ 190**

1.4.1 Public Awareness

This component seeks to increase public awareness of energy efficiency and conservation matters, and educates customers in regards to the availability of DSM programs. To promote the Company's incentive programs, collateral such as brochures, posters, point-of-sale materials, business case reports and promotional items is required. Collateral and promotional items will be distributed to residential customers at trade shows and community events. It will also be provided to trade allies (electrical contractors, appliance retailers, heat pump contractors) for distribution to customers. The point-of-sale materials highlighting energy efficiency and conservation will be provided to wholesale and retail partners that sell energy efficiency equipment.

Targeted information campaigns with specific messaging about programs and energy efficiency may be purchased for trade magazines, newsletters and other industry focused information pieces.

1.4.2 Community Energy Planning

This element of Supporting Initiatives will be used to collaborate with local governments to improve the energy efficiency elements of zoning and applicable by-laws.

1.4.3 Trades Training

FBC provides sponsorships for training and support for a number of initiatives from the building trades and electrical non-profit trade organizations[1], as well as support for energy management planning training like Natural Resources Canada's "Spot the Savings" workshops. Committed to growing the energy efficiency knowledge amongst the trades, FBC will continue to provide this support.

1.4.4 Education Programs

Elementary Schools

FBC has long supported elementary, middle and high school energy conservation education initiatives through financial sponsorship of educational events (such as science fairs and tours) and programs (Environmental Mind Grind, Climate Change Showdown) and delivery of curriculum approved longer-term educational programs through non-profit organizations like the Elements Society's Destination Conservation program. FBC will continue to build on existing partnerships and seek additional opportunities in 2014-18.

[1] TECA (Thermal Environmental Comfort Association), SICA (Southern Interior Construction Association), CHBC (Canadian Home builders Association), BCSEA (BC Sustainable Energy Association), GeoExchangeBC, etc.

Post-Secondary

FBC continues to support energy efficiency training opportunities such as the Okanagan College “Home for Learning”, and providing guest lecturers upon request e.g. Selkirk College Environmental program.

PowerSense, in partnership with FEU, is also sponsoring the university and college focused “Do It in the Dark” and “Shut the Sash” programs.

1.4.5 Codes and Standards

A number of international and national organizations such as the Consortium for Energy Efficiency, the Canadian Standards Association, and Natural Resources Canada are working to set new efficiency standards for consumer electronics, appliances, and lighting products amongst other equipment and technologies. Similarly local, provincial and federal governments are setting policy and regulations to increase as-built energy efficiency performance or raise awareness (e.g. EnerGuide building ratings). FBC will support codes and standards policy development and research, through in-kind and financial co-funding arrangements.

1.5 *PLANNING AND EVALUATION*

Planning and evaluation of the DSM initiatives are required to properly plan and control the proposed DSM expenditures and ensure the energy savings targets are prudently met. This expenditure includes provisions for planning and evaluation staff, who perform project due diligence including savings verification. The P&E budget also includes external expertise and facilitating the DSM Advisory Committee.

The following table shows the major planning and evaluation cost elements and the plan cost for 2014-18 period.

Table H1-6: Planning and Evaluation Expenditures

Component	2014 Plan $(000s)	2015 Plan $(000s)	2016 Plan $(000s)	2017 Plan $(000s)	2018 Plan $(000s)
Salaries (loaded)	282	290	299	308	317
Office Expenses, incl training	40	40	40	40	40
Consulting Fees	65	65	65	65	65
M&E Reports	100	100	100	100	100
DSMAC	5	5	5	5	5
P&E sub-Total	**$ 492**	**$ 500**	**$ 509**	**$ 518**	**$ 527**

Updating the FBC DSM Plan at regular intervals ensures that new and emerging commercially available DSM measures are taken into account, avoided cost assumptions are updated and the appropriate program course corrections are made.

1.5.1 Monitoring and Evaluation

Attachment H3 contains FBC's Monitoring and Evaluation Plan over the 3-year period of 2013-2015, inclusive. This plan is necessary to ensure that the DSM program expenditures will yield the energy savings expected and that the programs are operating effectively. The Monitoring and Evaluation Plan recommends approximately two major program reviews and three process reviews be undertaken each calendar year.

Monitoring and Evaluation of energy efficiency programs provides internal and external accountability by reducing uncertainty in the estimates of energy and demand savings, and by determining the cost effectiveness of these programs compared to other energy resource options.

1.6 INTEGRATION WITH FEU'S ENERGY EFFICIENCY AND CONSERVATION (EEC) PROGRAM

FBC will continue to work towards full integration of the marketing and processing of FBC and FEU program offers for customer-facing components of program offers, especially in the shared service territory. The intent is to provide customers with "one-stop" information and program access via the website, other marketing collateral and face-to-face interactions.

FBC will also continue to collaborate with BC Hydro, the Ministry of Energy and Mines and NRCan whenever appropriate to design and promote programs that support market transformation.

Table H1-7: Summary Table of FBC 2014-18 DSM Plan

1	Program Area	Plan Savings (MWh/year)					Plan Cost $(000s)					Benefit/Cost Ratios				
2		2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	TRC	mTRC	Utility	Participant	RIM
3	**Programs by Sector**															
4	Residential	5,800	5,783	5,615	5,511	5,407	1,037	1,081	1,008	1,015	1,024	1.2	1.3	3.5	5.5	0.5
5	General Service	6,200	6,304	6,408	6,512	6,616	1,134	1,166	1,195	1,223	1,256	1.4	1.7	3.3	5.2	0.6
6	Industrial	800	800	800	800	800	148	150	152	154	156	2.8	2.8	5.7	13	0.7
7	**Sub-total Programs:**	**12,800**	**12,887**	**12,823**	**12,823**	**12,823**	**2,319**	**2,397**	**2,355**	**2,392**	**2,436**	**1.4**	**1.5**	**3.9**	**5.6**	**0.6**
8	Supporting Initiatives						190	190	190	190	190					
9	Planning & Evaluation						492	500	509	518	527					
10	Total (incl. Portfolio):						**3,001**	**3,087**	**3,054**	**3,100**	**3,153**	**1.2**	**1.4**	**3.7**		**0.6**
11	**Residential Programs**															
12	Building Envelope	1,881	1,881	1,881	1,881	1,881	295	299	301	305	308	1.1	1.3	4.8	5.0	0.5
13	Heat Pumps	553	553	553	553	553	158	159	161	163	164	1.1	1.1	2.4	5.7	0.5
14	Lighting	2,136	2,067	1,997	1,928	1,859	176	171	164	158	153	1.4	1.4	5.9	4.9	0.5
15	New Home	98	98	98	98	98	67	68	68	69	70	0.6	1.2	1.2	5.3	0.4
18	Water heating	425	440	455	470	485	99	103	108	112	119	1.6	1.9	2.1	18	0.4
19	Low Income & Rental	707	744	631	581	531	242	281	206	208	210	0.8	0.8	1.0	-	0.4
21	**Total**	**5,800**	**5,783**	**5,615**	**5,511**	**5,407**	**$ 1,037**	**$ 1,081**	**$ 1,008**	**$ 1,015**	**$ 1,024**	**1.2**	**1.3**	**3.5**	**5.5**	**0.5**
22	**General Service Programs**															
23	Lighting	3,359	3,463	3,567	3,671	3,775	510	535	557	579	603	1.7	2.0	3.4	9.2	0.6
24	BIP	2,641	2,641	2,641	2,641	2,641	592	598	605	611	619	1.1	1.5	3.1	4.0	0.6
27	Irrigation	200	200	200	200	200	32	33	33	33	34	2.1	2.1	7.3	6.3	0.6
28	**Total**	**6,200**	**6,304**	**6,408**	**6,512**	**6,616**	**$ 1,134**	**$ 1,166**	**$ 1,195**	**$ 1,223**	**$ 1,256**	**1.4**	**1.7**	**3.3**	**5.2**	**0.6**
29	**Industrial Programs**															
31	Ind Efficiency	800	800	800	800	800	148	150	152	154	156	2.8	2.8	5.7	13	0.7
32	**Total**	**800**	**800**	**800**	**800**	**800**	**$ 148**	**$ 150**	**$ 152**	**$ 154**	**$ 156**	**2.8**	**2.8**	**5.7**	**13**	**0.7**

Attachment H2

SEMI-ANNUAL DSM REPORT
YEAR ENDED DECEMBER 31, 2012

FortisBC Inc.

Semi-Annual DSM Report for the Year Ended December 31, 2012

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REPORT OBJECTIVE

This report provides highlights of FortisBC Inc.'s (FortisBC or the Company) Demand Side Management (DSM) programs for the year ended December 31, 2012. The report reviews the progress of FortisBC's PowerSense program in meeting the approved DSM Plan and incenting FortisBC's customers to improve their energy efficiency. The report also provides a summary of the progress on integration and collaboration of its DSM programs with other BC Utilities[1]. A summary of PowerSense program activities in 2012 is also presented, with a comparison of actual energy savings and costs to Plan, where applicable, and provides a statement of financial results including benefit/cost ratios. Finally, a summary of historical FortisBC DSM costs and energy savings for the past five years is included in Appendix B.

OVERVIEW OF RESULTS FOR THE YEAR ENDED DECEMBER 31, 2012

Energy efficiency savings for the year ended December 31, 2012 were 31.6 GWh, or 99 percent of the 32.0 GWh Plan. The commercial sector led performance, achieving more than 17 GWh of savings. Company costs incurred were $7,300,000 or 94 percent of the $7,731,000 Plan. Adding customer costs to the Company's program costs yields a Total Resource Cost (TRC) of $12,833,000 with an overall TRC benefit/cost ratio of 1.6. The method used to determine benefits is provided in the Financial Results section.

OVERVIEW OF PROGRAM ACTIVITIES

The four priorities PowerSense identified in early 2012 continued through to the end of the year. The priorities were: 1) existing program process improvements; 2) new program development; 3) continued partnership and program delivery collaboration with other BC utilities and municipal, provincial and federal governmental agencies; and 4) integration planning with FortisBC Energy Utilities' (FEU) Energy Efficiency and Conservation (EEC) department. The following section provides a brief overview of each priority and is concluded with a summary of the programs offered by PowerSense in 2012.

1. PROGRAM PROCESS IMPROVEMENT

Due to changing circumstances and expanded budgets, many programs required fine-tuning to improve efficiency and effectiveness. Therefore, process improvement was a focus for the whole of 2012. This included refining marketing strategies and improving marketing materials, as well as reinvigorating a number of major programs.

The FortisBC PowerSense brand was reaffirmed for use for both gas and electricity programs in the Shared Service Territory[2] (SST) and the PowerSense website redesign was started.

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[1] British Columbia Utilities Commission (BCUC or the Commission) Order G-110-12, Directive 51.

[2] The Shared Service Territory (SST) is where the service territory of FortisBC Energy Utilities' (comprised of FortisBC Energy Inc., FortisBC Energy Vancouver Island Inc. and FortisBC Energy Whistler Inc.) and the service territory of FortisBC Inc. overlap.

PowerSense also partnered with FEU's EEC to reach and actively engage contractors and trade organizations to help disseminate energy efficiency programs and PowerSense messaging.

Emphasis was placed on the commercial and industrial sector custom offer programs to improve monitoring, verification and evaluation, legal documentation and program structure to ensure that energy savings can be documented and verified consistently.

PowerSense received approval from the British Columbia Utilities Commission (BCUC or the Commission) in Order G-110-12 to procure an end-to-end DSM business process management platform. Business case scenarios and process mapping were undertaken to define the requirements for the new system.

2. NEW PROGRAMS

A number of new programs that broadened PowerSense's reach and product offerings were introduced in 2012. In the early part of the year, programs including a heat pump tune-up program, known as the TLC Heat Pump program, Irrigation Pumping, and Low-Income Lighting Direct Installation were introduced. The Reduce Your Use program was launched in mid-year to coincide with the introduction of the inclining block Residential Conservation Rate (RCR).

The Product Rebate Program and its companion On-Line Energy Assessment tool were introduced in the fall. The program was designed to help small to medium size businesses determine which energy efficiency improvements would suit their business and to provide them with easy access to a large set of prescribed rebates. Customers access the program via a custom-built online application form, which assists in addressing the issue of customer attribution. The online format provides a cost-effective means of reaching a more difficult to reach customer segment. The Product Rebate Program replaces the Wholesale Lighting Program, which was successful but had issues with customer attribution.

The On-Bill Finance pilot project, which is marketed as the Residential Energy Efficiency Loan Program, was mandated by the provincial government and provides loans of up to $10,000 to residential customers in the South Okanagan to make energy efficiency improvements to their homes. The loans are to be repaid on the customers' electricity bills over the next 10 years. This pilot program was launched in the fall and by the end of 2012 none of the customers who applied had successfully met the eligibility requirements. The stringency of the eligibility requirements will be reviewed as part of the assessment of the pilot project.

3. COLLABORATION

The successful collaboration with the British Columbia Ministry of Energy, Mines and Natural Gas' (the Ministry) LiveSmart BC residential and commercial programs continued. The small business lighting installation program FLIP (FortisBC/LiveSmart BC Lighting Incentive Program) garnered a large amount of savings for the commercial sector, as did the LiveSmart BC residential program for the residential sector. As the LiveSmart BC program structure and funding is changing for 2013, PowerSense worked closely with the Ministry, BC Hydro and EEC staff in 2012 to support and redesign the program.

PowerSense also worked with several municipal governments to conduct pilot projects using high-impact marketing strategies to encourage residents and small businesses to make energy efficiency improvements. The Rossland Energy Diet and Nelson Hydro Eco-Save programs were so successful that Natural Resources Canada (NRCan) and Columbia Basin Trust provided significant funding to test program scalability in 2013. PowerSense won the Climate and Energy Action Award for Public Sector Collaboration for the Rossland Energy Diet project.

PowerSense staff also provided expertise to the Cities of Kelowna and Penticton to help develop their Greenhouse Gas Emissions Reduction Plans. Similarly, they worked with First Nations in the region to secure extra funding and rebates and made design recommendations for efficiency improvement projects. An example of this collaboration is the Penticton Indian Band's unique super-efficient housing project, with seven EnerGuide 90[3] rated houses and one Passivhaus[4] under construction.

4. INTEGRATION

PowerSense worked together with the FEU EEC team to design a number of new dual-fuel programs in the SST, which were launched in the later part of 2012, including:

- The above-mentioned Product Rebate Program, which provides online access to prescriptive rebates for a range of electric and gas energy efficiency measures including lighting, pumps and motors, space heating and cooling,and hot water systems. The program will address the often underserved small to medium commercial sector and incorporates EEC's Commercial Boiler and Water Heater programs;
- A combined Contractor program to better communicate with the contractors that provide and install energy efficiency measures in the SST. Direct marketing to these important stakeholders will also help PowerSense reach more customers at the time when they are making buying decisions;
- The above-mentioned On-Bill Financing pilot project in the South Okanagan for low-interest loans up to $10,000 for both gas and electricity customers to install Energy Efficiency (EE) improvements in their homes; and
- The EEC and PowerSense New Home program measures were combined into a joint application process to serve gas and electric customers in the SST.

These efforts added to the list of existing jointly marketed programs: the Tap by Tap program (water-savings measures), Energy Star clothes washer rebate program, and Energy Saving Kits for low-income households. PowerSense and EEC also collaborated and shared costs on print materials, educational tools, community outreach and advertising campaigns in the SST. A cost-

[3] EnerGuide is an energy efficiency rating system for houses, where 0 is least efficient and 100 is most efficient, requiring no purchased energy. EnerGuide - http://oee.nrcan.gc.ca/residential/personal/16352

[4] Passivhaus is an energy efficiency standard for buildings that incorporates passive heating and cooling in the building design. Canada passive house website - http://www.passivehouse.ca/

sharing principles agreement was developed to ensure the appropriate allocation of costs for joint DSM projects[5].

POWERSENSE PROGRAMS OFFERED IN 2012

The following tables summarize the PowerSense program offerings and indicate program status and progress of integration with FEU's EEC programs.

Table 1 - Residential Programs 2012

Program and Measures	Status	Integrated with FortisBC Energy Utilities for combined offer
Energy Star Appliances	Ongoing	Yes[6] (clothes washers)
Energy Star Electronics	Ongoing	No (electricity only)
Energy Star Retail Lighting Rebate	Ongoing	No (electricity only)
Heat Pump (Air Source and Geo-Exchange)	Ongoing	No (electricity only)
TLC Heat Pump Maintenance	Enhanced	No (electricity only)
New Home ▪ Performance • EnerGuide Ratings 80/85 ▪ Prescriptive • Lighting • Appliances • Insulation • Heat pumps • NEW: Fireplaces (gas) • NEW: Hot water (gas)	Ongoing	In progress
Home Improvement (Retro-fit) • Windows and doors • Lighting • Appliances • Insulation • Heat pumps • Heat pump loan option • NEW: Fireplaces (gas) • NEW: Hot water (gas)	Ongoing	In progress

[5] For joint non-program specific projects, a customer base ratio is used to allocate costs depending on whether the project applies to the overall FEU service region (including FortisBC's service area) or to the SST only. For programs that are customer specific, the cost allocation is determined by number of participants and/or respective electricity and natural gas savings realized.

[6] Based on fuel source of hot water tank.

Program and Measures	Status	Integrated with FortisBC Energy Utilities for combined offer
LiveSmart BC (Retro-fit) • Windows and doors • Insulation • Heat pumps • Hot water	Ongoing	Yes
Reduce Your Use (energy assessments)	New	No (electricity only)
On-Bill Financing	New	Yes
Low Income – Direct Installation Lighting	Ongoing	No (electricity only)
Low Income – Energy Savings Kits	Ongoing	In progress
Rental and Low-Income Housing	In-Design	Yes
Supporting Initiatives	Ongoing	Yes (where appropriate)
Contractor program	New	Yes (where appropriate)
WaterSavers (Tap by Tap)	Enhanced	Yes

Table 2 - Commercial and Industrial Programs 2012

Program and Measures	Status	Integrated with FortisBC Energy Utilities for combined offer
Product Rebate Program • Lighting • Pumps and fans • Compressors • Refrigeration • HVAC • Boilers (gas) • Water Heaters (gas)	New	Yes
Building Improvement – New	Ongoing	No
Building Improvement – Retro-fit	Ongoing	No
Building Optimization	Ongoing	In progress
Partners in Energy	Ongoing	No
Energy Efficiency Studies	Ongoing	In progress
Industrial Efficiency	Ongoing	No
Irrigation Pumping	New	No (electricity only)
Green Motors (motor rewinds)	Ongoing	No (electricity only)

ENERGY SAVINGS BY SECTOR

The energy savings that PowerSense achieved in the year ended December 31, 2012, are shown in the table below.

Table 3 - Energy Savings by Sector

SECTOR	Plan	Actual	% of Plan
	GWh		Achieved
Residential	16.1	12.8	79%
Commercial	13.4	17.9	134%
Industrial	2.5	0.9	38%
Total Savings (GWh)	**32.0**	**31.6**	**99%**

Note: Minor differences due to rounding.

Overall PowerSense was just under the Plan goal of 32.0 GWh savings. Commercial sector energy savings were above Plan at 134 percent. Residential and Industrial sector energy savings were under Plan at 79 percent and 38 percent respectively. These results are discussed in more detail in the following sections.

DETAIL OF ENERGY SAVINGS

The following tables provide details on the DSM energy savings in each sector, including DSM activities in the service territories of the Municipal Wholesale customers.

Table 4 - Residential Energy Savings

RESIDENTIAL	Plan	Actual	% of Plan
	GWh		Achieved
Home Improvement Program	8.3	5.9	71%
Low Income	1.8	1.1	59%
Residential Lighting	2.5	2.6	103%
Heat Pumps	3.4	2.2	64%
New Home Program	0.1	1.0	1155%
Total Savings (GWh)	**16.1**	**12.8**	**79%**

Note: Differences due to rounding.

In the year ended December 31, 2012, the energy saving results from Residential programs were 79 percent of Plan. The New Home and Residential Lighting programs exceeded Plan. The Heat Pump, Home Improvement and Low Income programs fell short of forecast. Customer participation in the New Home program continues to exceed plan expectations. The point-of-purchase incentive campaign in March-April and October-November were effective and contributed to the success in Residential Lighting.

The LiveSmart BC collaboration resulted in 2.1 GWh of retrofit energy savings, which are recorded in the Heat Pump and Home Improvement (HIP) programs. Decreased customer uptake of the LiveSmart BC program was likely due in part to the cancellation of the federal ecoEnergy residential retrofit incentive program.

In 2012, the Low Income program distributed approximately 950 Energy Saving Kits (ESKs) and concluded the direct install lighting program in the Okanagan. By year end, auditing for the Kootenay phase of the direct install lighting program was well under way, with installations to be completed in the following year.

Table 5 - Commercial Energy Savings

COMMERCIAL	Plan	Actual	% of Plan
	GWh		Achieved
Lighting	7.4	14.3	193%
Building and Process Improvement	3.4	2.0	57%
Water Handling and Infrastructure	2.6	1.7	65%
Total Savings (GWh)	**13.4**	**17.9**	**134%**

Note: Minor differences due to rounding.

The Commercial sector recorded savings of 17.9 GWh, or 134 percent of Plan. The majority of these savings were realized through the Commercial lighting programs, which include both "at the counter" product rebates and custom lighting retrofits, such as those installed at a large department store, producing 0.3 GWh of savings. Another large component of the Commercial lighting programs was the FLIP direct installation program, a collaborative effort with the LiveSmart BC Business program. FLIP continued to be very popular in 2012 and contributed 3.7 GWh of savings.

Examples of Building and Process Improvement (BIP) projects include a district heating system at a post-secondary educational institution in the Okanagan (0.6 GWh savings) and insulation and heating system upgrades at a community recreation complex in the Kootenays (0.2 GWh savings).

The second half of a large water infrastructure project with an Okanagan municipality was concluded in 2012, which contributed 1.5 GWh of the savings in the Water Handling and Infrastructure program. The Irrigation Pumping program was launched in June and no savings were realized in 2012.

Table 6 - Industrial Energy Savings

INDUSTRIAL	Plan	Actual	% of Plan
	GWh		Achieved
Industrial Efficiency	2.3	0.9	41%
Integrated EMIS	0.2	0.0	0%
Total Savings (GWh)	**2.5**	**0.9**	**38%**

Note: Minor differences due to rounding.

The Industrial Programs achieved savings of 0.9 GWh, or 38 percent of the 2.5 GWh Plan. Although a number of industrial customers started major retro-fit projects in 2012, few of them were completed in 2012. As a result, the industrial sector's savings were below Plan. An example of an Industrial Efficiency project from 2012 is the installation of variable speed drives on process equipment at a Kootenay lumber mill resulting in 0.3 GWh of energy savings.

An example of an industrial project that was initiated in 2012 involves collaboration between EEC and PowerSense to co-fund an energy assessment for a sawmill in the South Okanagan to determine energy savings opportunities. This project will also involve the use of an Energy Management Information System (EMIS) that will enable the customer to manage both electricity and gas use.

The table below disaggregates the Wholesale DSM savings, which are included in the sector tables above.

Table 7 - Wholesale Energy Savings by Municipality

WHOLESALE ACTIVITY	GWh	MW	% of GWh*
Kelowna	3.4	0.5	60%
Penticton	0.8	0.1	15%
Summerland	0.5	0.2	10%
Grand Forks	0.1	0.02	3%
Nelson	0.8	0.1	13%
Total Savings (Wholesale)	**5.6**	**1.0**	**100%**

**Of savings attributable to the Wholesale class*

Note: Minor differences due to rounding

The total Wholesale energy savings, which were acquired within the service areas of the five municipal electric utilities served by FortisBC, were 5.6 GWh and 1.0 MW in 2012. The largest DSM savings results occurred within Kelowna and Penticton municipal utility service areas (the municipalities with the largest number of customers).

PROGRAM COSTS BY SECTOR

The table below presents the actual costs incurred in the year ended December 31, 2012, compared to the approved Plan. The percent of plan savings achieved is shown in the table for comparison purposes.

Table 8 - Costs by Sector

SECTOR/COMPONENT	Plan ($000s)	Actual	% of Plan Costs	% of Plan Savings
Residential	3,717	2,564	69%	79%
Commercial	2,199	3,020	137%	134%
Industrial	350	173	49%	38%
Supporting Initiatives	725	816	113%	-
Monitoring & Evaluation	303	303	100%	-
Planning & Admin	437	425	97%	-
Total	**7,731**	**7,300**	**94%**	**99%**

Note: Minor differences due to rounding.

Costs amounted to $7,300,000, or 94 percent of the 2012 Plan. A breakdown of utility program costs per sector or program component follows. Appendix A contains an additional breakdown of total program costs, including the customer portion of project costs.

DETAIL OF COSTS

The following tables provide details on the DSM program costs for each sector and component in the PowerSense portfolio.

Table 9 - Residential Costs

RESIDENTIAL	Plan ($000s)	Actual	% of Plan Achieved
Home Improvement Program	1,966	969	49%
Low Income	677	308	45%
Residential Lighting	328	337	103%
Heat Pumps	703	636	90%
New Home Program	43	314	731%
Total	**3,717**	**2,564**	**69%**

Note: Minor differences due to rounding.

The utility cost of Residential programs was $2,564,000, or 69 percent of Plan for 2012. The New Home program continues to be very successful and while the costs are over budget, they are commensurate with savings. Low uptake of energy efficiency renovations in existing homes contributed to expenditures below plan for the Home Improvement program. The Low Income program was also underspent, partly due to the fact that installations for the Low Income Direct Install Lighting program in the Kootenays were delayed into the beginning of 2013.

Table 10 - Commercial Costs

COMMERCIAL	Plan	Actual	% of Plan
	($000s)		Achieved
Lighting	1,157	2,152	186%
Building and Process Improvement	659	612	93%
Water Handling and Infrastructure	383	255	67%
Total	**2,199**	**3,020**	**137%**

Note: Minor differences due to rounding.

Commercial sector costs in 2012 amounted to $3,020,000 or 137 percent of Plan. While this is over budget, it is commensurate with the savings achieved in the Commercial sector, which were 134 percent of Plan. The largest cost component of Commercial programs was the Lighting program, which includes incentives paid through the LiveSmart BC FLIP collaboration. Incentives paid to Commercial Lighting program participants in 2012 amounted to $1,786,000 compared to $794,000 Plan, a variance of $992,000. The expenditures for Water Handling and Infrastructure are under budget, partially because it incorporates the Irrigation program. PowerSense launched the Irrigation program in June, but had low uptake from the irrigation rate class. In 2013 the program will be assessed to determine causes of low participation and the steps to be taken to improve it.

Table 11 - Industrial Costs

INDUSTRIAL	Plan	Actual	% of Plan
	($000s)		Achieved
Industrial Efficiency	323	163	51%
Integrated EMIS	27	10	36%
Total	**350**	**173**	**49%**

Note: Minor differences due to rounding.

Industrial sector costs incurred by the Company were $173,000 for the period, or 49 percent of Plan. The Industrial sector is characterized by large projects that generally occur less frequently than in other sectors. A couple of large projects were initiated in 2012 but were not completed by year end and thus, FortisBC incentive costs will not be incurred until project completion. Energy Management Information System (EMIS) software is a long-term program with up-front costs and savings that will be realized later in the process. In 2012 the Company committed to co-funding the EMIS software at an Okanagan lumber mill.

Portfolio level costs, which are not specifically associated with individual programs, include the following components: Supporting Initiatives, Monitoring and Evaluation, and Planning and Administration. These costs are summarized in the table below.

Table 12 - Portfolio Costs by Component

COMPONENTS	Plan	Actual	% of Plan
	($000s)		Achieved
Supporting Initiatives*	725	816	113%
Monitoring & Evaluation	303	303	100%
Planning & Administration	437	425	97%
Total	**1,465**	**1,544**	**105%**

**Including Conservation Culture*

Note: Minor differences due to rounding

The Supporting Initiative costs for 2012 were $816,000 or 113 percent of the $725,000 Plan. The Conservation Culture costs included in Supporting Initiatives were $360,000. Supporting Initiatives and Conservation Culture spending continues to drive community outreach and direct customer communication, which is a strong component of PowerSense programming. The three community ambassadors attended more than 200 community events and distributed clotheslines at over 80 locations. Whenever possible, outreach and community event sponsorship was done in collaboration with EEC.

The Earth Hour and Caught Hanging Out (clotheslines) promotions were expanded for 2012, and were once again well received. As part of Earth Hour, customers across the FortisBC service area sent in approximately 6,000 pledges, each committing to turn their lights off for one hour. This was more than triple the number of participants from 2011. The Caught Hanging Out campaign won the Natural Resources Canada ENERGY STAR Regional Utility of the Year award.

The Planning and Evaluation budget is separated into two main components: Monitoring and Evaluation (M&E), and Planning and Administration. M&E was on budget with costs of $303,000, or 100 percent of Plan. The Planning and Administration expenditure was $425,000, or 97% of Plan.

In Appendix A, Program Development costs are further broken out from the Planning and Administration costs.

FINANCIAL RESULTS

This section reviews the financial and benefit cost test results for 2012 and includes information about how the benefits were calculated for the Total Resource Cost test (TRC) and for the Modified Total Resource Cost test (MTRC)[7].

The table below presents the financial and benefit cost tests by program. It also includes the Planning and Evaluation costs, which are allocated to the programs by savings achieved.

Table 13 - Financial Results for Year Ended December 31, 2012 by Program

Program	Program Benefits	Utility Program Costs	Planning & Evaluation Costs			Customer Incurred Costs	Total Resource Costs	Benefits less Costs	Total Resource Benefit/Cost Ratio	
			Planning & Admin.	Monitoring & Eval.	Program Dev.					
	($000s)								TRC	MTRC
Residential										
Home Improvement	4,961	969	66	57	13	1,819	2,924	2,037	1.7	1.7*
Low Income	376	308	12	10	2	42	374	2	1.0	1.3**
Residential Lighting	1,063	337	29	25	6	181	577	485	1.8	1.8
Heat Pumps	1,774	636	24	21	5	1,050	1,735	39	1.0	1.5*
New Home Program	1,121	314	12	10	2	441	780	341	1.4	1.4
Residential Total	**9,295**	**2,564**	**143**	**122**	**29**	**3,532**	**6,390**	**2,905**	**1.5**	**1.6**
Commercial										
Lighting	7,737	2,152	159	137	32	1,044	3,525	4,212	2.2	2.2
Building and Process Improvement	1,689	612	22	19	4	607	1,264	425	1.3	1.3
Water Handling Infrastructure	1,433	255	19	16	4	261	555	877	2.6	2.6
Commercial Total	**10,858**	**3,020**	**200**	**172**	**41**	**1,912**	**5,344**	**5,514**	**2.0**	**2.0**
Industrial										
Industrial Efficiency	541	163	10	9	2	89	274	267	2.0	2.0
Integrated EMIS	-	10	-	-	-	-	10	(10)	-	- *
Industrial Total	**541**	**173**	**10**	**9**	**2**	**89**	**284**	**258**	**1.9**	**1.9**
Supporting Initiatives		816					816		-	-
Total	**20,694**	**6,572**	**353**	**303**	**72**	**5,533**	**12,833**	**7,861**	**1.6**	**1.7**

Note: Minor differences due to rounding.
** MTRC benefits used with some of the program measures.*
*** Low Income benefits increased by 30 percent.*

An overall total resource benefit/cost ratio of 1.6 was achieved in 2012. The benefit/cost ratios for the individual programs are also detailed in the table above. The Residential sector program performance resulted in a benefit/cost ratio of 1.5 and the Commercial sector achieved a benefit/cost ratio of 2.0 and the Industrial sector benefit/cost ratio was 1.9.

The Low Income program attained a benefit/cost ratio of 1.0, and with the 30 percent benefits lift as per the DSM Regulation, s4(2)(b), the benefit/cost ratio increased to 1.3.

Program benefits are calculated using the present value of avoided power purchase costs. For the TRC test, the present value of avoided power purchase costs is based on the long-term avoided power purchase cost[8] over the measure lifespan, plus a deferred construction expenditure factor. Total resource costs shown are a total of Company costs and customer

[7] As described in the Demand Side Management Regulation (326/2008 as amended in December 2011) of the *Utilities Commission Act*.

[8] As per the 2012-2013 Long Term Demand Side Management (DSM) Plan, approved by BCUC Order G-110-12, the long-term avoided power purchase cost is $84.94/MWh .

costs. The customer portion of costs are the incremental costs of new construction measures and the energy efficiency "portion" of retrofit measure costs.

The estimated modified total resource benefit/cost ratio is also shown in the table above. The benefits used in the MTRC were estimated using a long-term avoided power purchase cost[9] plus a fifteen percent adder for non-energy benefits (NEB), consistent with the Company's application of the DSM Regulation in its 2012-13 DSM Plan filed as part of the 2012 – 2013 Revenue Requirements Application and approved by Order G-110-12[10]. The MTRC benefits were estimated based on the following measures that were subject to the MTRC in the 2012 – 2013 RRA:

- Residential:
    - Building Envelope – windows;
    - Heat Pumps – geo exchange, air source conversion, and ductless; and
    - Appliances – freezers.
- Industrial:
    - Integrated – EMIS.

The MTRC benefits estimation does not include the commercial lighting – controls measure, as it was not feasible to separate it from the other commercial lighting measures in the program results.

The MTRC does not differ substantially from the TRC results. Overall, the benefit/cost ratio increased from 1.6 to 1.7 with the MTRC. The Residential benefit/cost ratio increased from 1.5 to 1.6. Most notably, the heat pump benefit/cost ratio increased from 1.0 to 1.5 with the use of the MTRC. Commercial and Industrial benefit/cost ratios were unaffected by incorporation of the MTRC.

The Company's DSM expenditure related to the measures that are subject to the MTRC was estimated to be $692,000 or 9.5 percent of total DSM expenditure, which is within the regulated MTRC impact cap.

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[9] As per the 2012-2013 Long Term Demand Side Management (DSM) Plan, approved by BCUC Order G-110-12, the long-term avoided power purchase cost is $111.96/MWh, for BC "clean" new resources.

[10] FortisBC 2012-2013 Revenue Requirements Application, Exhibit B-23, Oral Hearing Undertakings from March 8, 2012, Table 31-1.

APPENDIX A - DSM SUMMARY REPORT IN BCUC FORMAT

Table 14 - FortisBC Demand Side Management Summary Report for Year Ended December 31, 2012

Sector/Program	Utility Program Costs			Planning and Evaluation			Total	Customer	Total			Benefit/Cost Ratios				
	Direct Incentives	Direct Information	Program Labour	Planning & Admin.	Monitoring & Eval.	Program Dev.	Utility Costs	Incurred Cost	Resource Cost	Program Benefits*	Energy Savings	Total Resource	Modified Total Resource	Rate Impact	Uility Cost	Levelised Cost
	($000s)										MWh					¢/kWh
Residential																
Home Improvements Program	696	35	238	66	57	13	1,105	1,819	2,924	4,961	5,903	1.7	1.7	0.7	4.5	5.4
Low Income	199	10	98	12	10	2	332	42	374	376	1,054	1.0	1.3	0.5	1.1	8.9
Residential Lighting	225	41	71	29	25	6	397	181	577	1,063	2,599	1.8	1.8	0.7	2.7	5.6
Heat Pumps	450	38	148	24	21	5	686	1,050	1,735	1,774	2,161	1.0	1.5	0.6	2.6	8.9
New Home Program	217	18	79	12	10	2	338	441	780	1,121	1,040	1.4	1.4	0.7	3.3	6.7
Residential Total	**1,787**	**144**	**633**	**143**	**122**	**29**	**2,858**	**3,532**	**6,390**	**9,295**	**12,757**	**1.5**	**1.6**	**0.7**	**3.3**	**6.4**
Commercial																
Lighting	1,786	47	320	159	137	32	2,481	1,044	3,525	7,737	14,256	2.2	2.2	0.6	3.1	3.3
Building and Process Improvement	393	78	141	22	19	4	657	607	1,264	1,689	1,959	1.3	1.3	0.7	2.6	6.6
Water Handling Infrastructure	186	6	64	19	16	4	294	261	555	1,433	1,677	2.6	2.6	0.8	4.9	3.4
Commercial Total	**2,365**	**131**	**524**	**200**	**172**	**41**	**3,432**	**1,912**	**5,344**	**10,858**	**17,892**	**2.0**	**2.0**	**0.7**	**3.2**	**3.7**
Industrial																
Industrial Efficiency	102	4	57	10	9	2	185	89	274	541	937	2.0	2.0	0.8	2.9	4.4
Integrated EMIS	-	4	5	-	-	-	10	-	10	-	-	0.0	0.0	0.0	0.0	-
Industrial Total	**102**	**8**	**63**	**10**	**9**	**2**	**195**	**89**	**284**	**541**	**937**	**1.9**	**1.9**	**0.8**	**2.8**	**4.5**
Supporting Initiatives	-	515	301	-	-	-	816	-	816			-	-	-		-
TOTAL	**4,254**	**797**	**1,522**	**353**	**303**	**72**	**7,300**	**5,533**	**12,833**	**20,694**	**31,586**	**1.6**	**1.7**	**0.7**	**2.8**	**5.1**

Note: Minor differences due to rounding

** Benefits calculated using the long-term avoided power purchase cost of $84.94/MWh.*

APPENDIX B - HISTORICAL SUMMARY OF FORTISBC'S DSM COSTS AND ENERGY SAVINGS

Table 15 - Historical FortisBC DSM Costs and Energy Savings 2007- 2008

		1	2	3	4	5	6	7	8	9	10	11	12	13	14
		2007 (Actual)							**2008 (Actual)**						
		Spend ($000s)			Energy Savings (MWh)			TRC[3]	Spend ($000s)			Energy Savings (MWh)			TRC[3]
		Planned	Actual	Variance	Planned	Actual	Variance	(B/C)	Planned	Actual	Variance	Planned	Actual	Variance	(B/C)
1	**Residential**														
2	Home Improvements	98	78	20	500	500	-	1.5	135	62	73	385	331	(54)	0.8
3	Building Envelope[1]														
4	Heat Pumps	513	651	(138)	6,200	9,600	3,400	1.6	446	682	(236)	4,889	8,444	3,555	1.4
5	Residential Lighting	170	116	54	2,200	2,700	500	5.6	156	151	5	1,796	2,562	766	4.1
6	New Home Program	424	458	(34)	1,700	2,500	800	2.3	286	340	(54)	1,332	1,596	265	2.8
7	Appliances[1]														
8	Electronics[1]														
9	Water Heating[1]														
10	Low Income[1]														
11	Behavioural[1]														
12	*Residential Total*	**1,205**	**1,303**	**(98)**	**10,600**	**15,300**	**4,700**	**1.9**	**1,023**	**1,236**	**(213)**	**8,401**	**12,933**	**4,531**	**1.7**
13	**Commercial**														
14	Lighting	257	240	17	3,000	5,500	2,500	2.8	257	375	(118)	3,000	5,960	2,960	2.4
15	Building and Process Improvements	469	499	(30)	6,200	4,900	(1,300)	1.5	497	506	(9)	6,103	5,081	(1,022)	1.6
16	Computers														
17	Municipal (Water Handling)[2]														
18	Irrigation[2]														
19	*Commercial Total*	**726**	**739**	**(13)**	**9,200**	**10,400**	**1,200**	**2.0**	**754**	**881**	**(127)**	**9,103**	**11,042**	**1,939**	**1.9**
20	**Industrial**														
21	Compressed Air	37	30	7	700	400	(300)	1.0	58	22	36	700	210	(490)	1.2
23	EMIS														
22	Industrial Efficiencies	131	153	(22)	1,300	1,800	500	1.6	142	124	18	1,285	3,083	1,798	2.3
24	*Industrial Total*	**168**	**183**	**(15)**	**2,000**	**2,200**	**200**	**1.5**	**200**	**147**	**53**	**1,985**	**3,294**	**1,309**	**2.3**
25	**Programs Total**	**2,099**	**2,225**	**(126)**	**21,800**	**27,900**	**6,100**	**-**	**1,977**	**2,264**	**(287)**	**19,489**	**27,268**	**7,779**	**-**
26	Supporting Initiatives	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Planning & Evaluation	375	324	51	-	-	-	-	378	419	(41)	-	-	-	-
28	**Total**	**2,474**	**2,549**	**(75)**	**21,800**	**27,900**	**6,100**	**1.9**	**2,355**	**2,683**	**(328)**	**19,489**	**27,268**	**7,779**	**1.8**

[1] These programs were included in Home Improvements program

[2] Water Treatment and Wastewater Handling infrastructure were part of Building and Process Improvement

[3] Benefits calculated using RS3808 applicable at the time

Table 16 - Historical FortisBC DSM Costs and Energy Savings 2009-2010

		1	2	3	4	5	6	7	8	9	10	11	12	13	14
		2009 (Actual)							**2010 (Actual)**						
		Spend ($000s)			Energy Savings (MWh)			TRC³	Spend ($000s)			Energy Savings (MWh)			TRC³
		Planned	Actual	Variance	Planned	Actual	Variance	(B/C)	Planned	Actual	Variance	Planned	Actual	Variance	(B/C)
1	**Residential**														
2	Home Improvements	273	145	128	1,024	1,032	8	1.4	294	434	(140)	953	4,948	3,995	3.1
3	Building Envelope¹														
4	Heat Pumps	515	677	(162)	5,642	3,188	(2,454)	0.7	624	749	(125)	6,377	3,239	(3,138)	1.2
5	Residential Lighting	263	306	(44)	2,822	3,349	526	2.8	243	278	(35)	2,383	2,589	206	2.4
6	New Home Program	341	496	(155)	1,216	1,735	518	2.2	254	247	7	1,392	477	(915)	1.1
7	Appliances¹														
8	Electronics¹														
9	Water Heating¹														
10	Low Income¹								100	131	(31)	1,000	385	615	0.7
11	Behavioural¹														
12	*Residential Total*	**1,391**	**1,624**	**(233)**	**10,705**	**9,304**	**(1,401)**	**1.3**	**1,515**	**1,838**	**(323)**	**12,105**	**11,638**	**764**	**1.9**
13	**Commercial**														
14	Lighting	724	422	302	5,505	7,638	2,133	3.0	722	526	196	5,304	7,971	2,667	3.5
15	Building and Process Improvements	563	639	(75)	6,095	8,713	2,618	1.8	658	597	61	6,751	6,685	(67)	1.5
16	Computers														
17	Municipal (Water Handling)²														
18	Irrigation²														
19	*Commercial Total*	**1,287**	**1,060**	**227**	**11,600**	**16,351**	**4,751**	**2.2**	**1,380**	**1,123**	**257**	**12,055**	**14,655**	**2,600**	**2.1**
20	**Industrial**														
21	Compressed Air	71	41	30	811	398	(413)	0.9	87	25	62	938	114	(823)	0.7
23	EMIS														
22	Industrial Efficiencies	274	195	79	2,189	2,305	116	1.6	302	216	86	2,412	2,853	441	2.1
24	*Industrial Total*	**345**	**236**	**109**	**3,000**	**2,703**	**(297)**	**1.5**	**389**	**241**	**148**	**3,350**	**2,967**	**(383)**	**2.0**
25	**Programs Total**	**3,023**	**2,920**	**103**	**25,305**	**28,358**	**3,053**	**-**	**3,284**	**3,203**	**81**	**27,510**	**29,261**	**2,981**	**2.1**
26	Supporting Initiatives	141	141	0	-	-	-	-	148	155	(7)	-	-	-	
27	Planning & Evaluation	503	402	101	-	-	-	-	519	354	165	-	-	-	-
28	**Total**	**3,667**	**3,464**	**204**	**25,305**	**28,358**	**3,053**	**1.7**	**3,951**	**3,712**	**239**	**27,510**	**29,261**	**2,981**	**2.0**

¹ These programs were included in Home Improvements program

² Water Treatment and Wastewater Handling infrastructure were part of Building and Process Improvement

³ Benefits calculated using RS3808 applicable at the time

Table 17 - Historical FortisBC DSM Costs and Energy Savings 2011

		1	2	3	4	5	6	7
		2011 (Actual)						
		Planned	Actual	Variance	Planned	Actual	Variance	TRC[3] (B/C)
1	**Residential**							
2	Home Improvements	2,145	479	1,666	8,960	3,692	(5,268)	1.6
3	Building Envelope[1]							
4	Heat Pumps	694	532	162	3,397	2,257	(1,140)	1.0
5	Residential Lighting	438	239	199	3,420	3,308	(112)	2.2
6	New Home Program	54	205	(151)	105	689	584	1.0
7	Appliances[1]							
8	Electronics[1]							
9	Water Heating[1]							
10	Low Income	305	245	60	540	1,447	(907)	1.0
11	Behavioural[1]							
12	*Residential Total*	**3,636**	**1,700**	**1,936**	**16,422**	**11,393**	**(6,843)**	**1.3**
13	**Commercial**							
14	Lighting	1,114	1,995	(881)	7,370	20,577	13,207	2.3
15	Building and Process Improvements	572	606	(34)	3,010	1,386	(1,624)	0.7
16	Computers							
17	Municipal (Water Handling)	432	231	201	3,560	2,199	(1,361)	1.6
18	Irrigation[2]							
19	*Commercial Total*	**2,118**	**2,832**	**(714)**	**13,940**	**24,162**	**10,222**	**1.9**
20	**Industrial**							
21	Compressed Air							
23	EMIS	10	9	1	80	-	(80)	-
22	Industrial Efficiencies	603	128	475	9,280	794	(8,486)	2.5
24	*Industrial Total*	**613**	**137**	**476**	**9,360**	**794**	**(8,566)**	**2.4**
25	**Programs Total**	**6,367**	**4,669**	**1,698**	**39,722**	**36,349**	**(5,187)**	**1.8**
26	Supporting Initiatives	725	658	67	-	-	-	-
27	Planning & Evaluation	750	590	160	-	-	-	-
28	**Total**	**7,842**	**5,918**	**1,924**	**39,722**	**36,349**	**(5,187)**	**1.6**

[1] These programs were included in Home Improvements program

[2] Irrigation was included in Municipal (Water Handling)

[3] Benefits calculated using RS3808 applicable at the time

APPENDIX C - EXECUTIVE SUMMARY OF INDUSTRIAL EFFICIENCY PROGRAM EVALUATION REPORT

SAMPSON RESEARCH

Consulting Project

POWERSENSE INDUSTRIAL EFFICIENCY PROGRAM EVALUATION

FINAL REPORT

Prepared for:

PowerSense Dept.
FortisBC Inc.
Kelowna, British Columbia

By:

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January 29, 2013

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Disclaimer

The opinions expressed in this report are the responsibility of the authors, Sampson Research and Clearlead Consulting, and do not necessarily represent the views of FortisBC.

Currency Units

All dollar figures presented in this report, unless stated otherwise, are expressed in Canadian funds.

1 EXECUTIVE SUMMARY

1.1 Introduction

This report summarizes the findings from a process and impact evaluation of FortisBC's PowerSense Industrial Efficiency Program for 2007-10. Over these four years, 20 companies participated in the program and $325.7 thousand was paid out in financial incentives for 46 projects. Claimed energy and demand savings totalled 10.102 GWh and 1.2 MW respectively.

1.2 Evaluation Objectives and Methodology

The objectives of the evaluation included generating a program logic model, assessing the effectiveness of program communications, program tracking, customer satisfaction, and determining the program's net impact on energy and demand savings.

Methods used to evaluate the program included interviews with program management and delivery staff (n=4), review of program tracking records and documentation (n=18), survey of participants (n=16), and site-visits (n=9). Realization rates for energy and demand savings were derived based on the findings from site visits. An estimate of free ridership was derived using the participant survey. Participant spillover was assessed qualitatively.

1.3 Evaluation Findings

Highlights from the participant survey, review of program documents, site visits, desk reviews, and program savings are provided below.

1.3.1 Documentation and Record Keeping

Participant records and billing histories were reviewed for all participants. The level of documentation retained for participants varied considerably from project to project. Some files contained a substantial amount of data which were well described and annotated, while other project files contained very little data, or undocumented data and assumptions. Documentation was insufficient to assess program energy savings claims in 36% of the project measures evaluated.

Interviews with program staff identified an internal effort that begun in 2011 to standardize the information collected on projects. The primary objective of this effort is to address many of the deficiencies in record keeping identified through evaluations of PowerSense programs. Based on the review of program records and documentation for this evaluation, there is considerable room for improvement in this area. Future evaluations of the Industrial Efficiency Program should pay particular attention to this area.

The evaluation identified two projects in which energy savings were claimed despite no incentives being paid. In both cases, customer payback without the incentive was already less than two years. However, there was no documentation to support the claims to non-rebated energy savings.

1.3.2 Program Operations

The administrative burden on participants of the Industrial Efficiency Program is minimal. Participants are not required to complete an application, and no terms or conditions are placed on participants beyond those specified in FortisBC's Electric Tariff. Feedback provided via the site visits and the participant survey confirmed that participants like the ease of participating in the program and are satisfied with the amount time required to receive their rebate. There was some evidence of pre- and/or post-monitoring to confirm some operating parameters but there was no clear indication of the criteria used to determine whether measurement and verification (M&V) was required.

Communication between delivery staff and program management is frequent. Monthly progress reports allow staff to keep up to date on progress made towards energy savings targets. Program staff felt informed as to the status of the program and did not require improvements or changes to this area.

1.3.3 Program Marketing and External Communications

Outbound marketing for the Industrial Efficiency Program consists primarily of direct contact between field representatives and industrial customers, networking with industry stakeholders, training sponsorships, and activities through the Partners in Efficiency (PIE) program.

There is minimal marketing collateral for the program, and the PowerSense website for industry provides a high level overview of the program. Delivery staff bear primary responsibility for raising awareness of the program, primarily through direct customer contact. From the perspective of some participants, obtaining information about the program is an area needing improvement. The source of dissatisfaction revolved primarily around the difficulty reaching a field representative and/or obtaining information on the program through other means, notably the PowerSense website. Program staff acknowledged that the PowerSense website for the program needs improvement.

1.3.4 Other Barriers to Participation

Barriers to program participation that were highlighted by staff and/or inferred from the results of the participant survey included:

- A lack of published information on the program, primarily via the PowerSense website. The difficulty obtaining information on the program and its qualifying technologies was the most common reason for dissatisfaction with the program among surveyed program participants.
- The FortisBC tariff requirement that measurement and verification of savings occur for large projects (incentives exceeding $10,000). The cost of disrupting processes and operating systems for monitoring purposes was argued to sometimes exceed the amount of the rebate.
- The lack of an internal champion within the customer's organization to "sell" the energy efficient upgrade to management.
- Some program staff felt the payback criteria are too stringent and should be reduced to something less than two years. However, with a couple of exceptions, most participants surveyed indicated their internal payback criteria for energy and non-energy related projects were two years or longer.

1.3.5 Program Satisfaction

Overall, 81% of participants of the Industrial Efficiency Program during 2007-10 indicated they were satisfied with the program. Participants were most satisfied with the time it took to approve their application to the program, the time it took to receive the incentive from FortisBC, and the overall effort to participate in the program.

1.3.6 Free Riders and Spillover

Free ridership for the program during 2007-10 is estimated at 12%. This is an energy savings weighted estimate, based on the self-reported influence of the program and its incentive on the decision to implement the energy efficient investment.

Spillover for the Industrial Efficiency Program was explored qualitatively, and considered only non-incentivised investments in energy efficient equipment and processes within participants' facilities. Sixty-three percent (63%) of participants surveyed indicated their company had made additional energy efficient investments since participating in the Industrial Efficiency Program. Of these, 82% felt FortisBC had some influence on these decisions.

1.3.7 Persistence

Measure persistence for participants contacted during the evaluation was high. Of those surveyed by phone or receiving site visits, only one indicated that less than 100% of equipment that received a rebate was installed and operational. In that case, the rebated equipment was temporarily out of service awaiting parts for repair. Two participants of the 2007-10 program are no longer in business. In one case, FortisBC has completed proceedings for return of the rebate. Given the effort to recapture the incentive, energy and demand savings for this participant were excluded from both claimed and evaluated program savings. In the second case, the savings were too small to justify the expense of pursuing the return of the incentive. Evaluated program energy savings reflect this plant closure.

1.4 Impact Results

The findings from the site visits formed the primary basis for adjusting gross energy and demand savings claims. Evaluated gross energy savings were found to closely monitor claimed savings (99%), although there were several examples where the evaluators were unable to assess program savings claims due to either inadequate documentation or changes in personnel at the customer site which meant the on-site contacts were unable to recall or otherwise confirm the specifics of their company's participation in the FortisBC industrial program. In the absence of information or evidence to contradict program savings claims, savings estimates were accepted as is, subject to the recommendation that documentation of program assumptions and M&V procedures need to be significantly improved.

Realized energy and demand savings were then adjusted for free riders.

1.4.1 Evaluated Energy and Demand Savings

Evaluated energy and demand savings for the 2007-10 PowerSense Industrial Efficiency Program are summarized in Table 11. After adjustments, evaluated net energy savings (run rate) were 5.878 GWh, or

87% of program claimed energy savings. Demand savings were 0.605 MW, equivalent to 84% of program claimed demand savings.

Table 1: Net Program Savings (Run Rates)
FortisBC Industrial Efficiency Program: 2007-10

	GW.h/yr Run Rate	MW Run Rate
Gross Program Savings [1]	**6.764**	**0.717**
Less closed / non-operating businesses	0.018	0.000 [2]
Adjusted Gross Program Savings	**6.746**	**0.717**
Unrealized Savings [3]	0.067	0.029
Evaluated Gross Savings	**6.679**	**0.688**
Free Riders (12%)	0.801	0.083
Net Program Savings	**5.878**	**0.605**
Net Program Savings (%)	87%	84%

[1] Excludes energy and demand savings repatriated from closed sawmill.
[2] No demand savings.
[3] Energy Savings x (1 – 0.99), Demand Savings x (1 - 0.96)

1.5 Recommendations

Recommendations stemming from the Industrial Efficiency Program evaluation include:

1. **Increase the comprehensiveness and consistency of project documentation** – Documentation of projects receiving incentives under the Industrial Efficiency Program needs to be improved. The evaluation found that several projects could not be evaluated due to missing or poorly documented records. Recommendations for improving program documentation and record keeping include:

   - Ensure each file contains all the key documentation including a project description, pre- and post-monitoring data, annotated savings calculations, photos, correspondence, TRC test, incentive application, and contact details.
   - Develop a standardized documentation checklist for field representatives to follow. The list should be reviewed, signed off by the field representative and/or supervisor, and included within the project file.
   - Include a description of each project that will allow others to clearly understand the rebated measure(s) and the assumptions used to support the savings claims.
   - Ensure that contact details, phone numbers and site addresses are correct. Contact information should clearly differentiate who received the rebate cheque and a site specific contact.
   - Savings calculations, spreadsheets, and schedules for monitored data should be clearly documented and labelled. Methodologies and assumptions should accompany M&V findings.
   - For equipment installations, pre- and post-installation photos should be taken and kept with participant records.
   - Missing data or information should be noted and reasons for the omission provided.

2. **Consider requiring participants to complete and sign an application form** – Not intended as a barrier to participation, an application form would formalize the relationship between the customer and PowerSense program, including obligations and responsibilities for both parties. The form should include a project description, a description or check list of measures rebated, energy and demand savings, the amount of the financial incentive, and the obligation for monitoring if incentives exceed the threshold specified in the Tariff.

3. **Improve industrial customers' access to information about the program** – Participants of the Industrial Efficiency Program want improved access to information about the Industrial Efficiency Program, including application criteria and which technologies qualify for incentive. The PowerSense website is a low-cost but highly effective vehicle for providing this information. Improvements to the quality and quantity of information about the program on the site should be made a priority.

4. **Minimize claims to un-incentivized energy savings** – The evaluation identified situations where FortisBC claimed energy savings from projects where the customer payback was less than two years and no incentive was paid. Given the difficulty in evaluating the legitimacy of these claims in an ex-post context, the practice of claiming savings without incentive payout should be discouraged. If not discontinued, claims to un-incentivised energy savings claims should have documentation that supports the legitimacy of the savings claims.

5. **Increase the rigor of savings estimates by the use of pre- and post-retrofit M&V** – The use of M&V is strongly encouraged as a means of increasing the legitimacy of savings estimates. This can be as simple as a series of spot measurements taken over several days pre- and post-installation/retrofit. In cases where no 'before' situation exists (e.g., new construction), baseline assumptions should be clearly indicated, and post-installation measurements taken to confirm key savings assumptions.

6. **Consider load factor for savings from motor upgrades** – The review of program records identified cases where motor loading factors were not used, potentially overstating the energy savings. As motors seldom run fully loaded most of the time, projects rebating energy efficient motors should consider a motor load factor in the calculation of energy savings.

7. **Include an assumption for free riders –** Provisions for free riders should be mandatory for all new PowerSense business cases. Free rider estimates should be periodically reviewed and updated. Based on evaluation findings, a free rider rate of 10% to 15% is reasonable for future Industrial Efficiency Program business cases.

* * * * *

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APPENDIX D - EXECUTIVE SUMMARY OF COMMERCIAL LIGHTING PROGRAM EVALUATION REPORT

EVERGREEN ECONOMICS

Evaluation of the FortisBC Commercial Lighting Program

March 25, 2013

FORTIS BC™ powersense

Table of Contents

1 Executive Summary

1.1 Introduction

This report presents the findings of the impact and process evaluation of the FortisBC Commercial Lighting Program. As part of this effort, three program components were evaluated as part of the overall Commercial Lighting Program:

1. **FLIP.** The FortisBC Lighting Incentive Program (FLIP) is a direct install program that covers 100 percent of the installation costs of eligible lighting measures up to $5,500. Customers are eligible for this program if they install eligible lighting and their annual electricity costs are less than $20,000 annually.
2. **Custom Lighting.** The Custom program provides incentives for customers that are not eligible for the FLIP program. Through this program, a rebate is provided to cover a portion of the installation costs.
3. **Wholesale Products.** The Wholesale program provides discounted high efficiency lighting equipment to contractors through electrical distributors. The eligible lighting measures for the Wholesale program are the same as those for the Custom and FLIP programs.

1.2 Evaluation Methods

The evaluation relied on several analysis methods to collect information and derive results for both the impact and process evaluation:

- **Engineering analysis.** For the Custom program, a sample of lighting project applications was selected for a desk review (n = 30). Based on the review of the available information (and the spreadsheet tools used by the program to calculate savings), an engineering adjustment factor was calculated from the sample and then applied to the Custom participant population. A review of the Excel savings calculators for both the Custom and FLIP programs was also conducted.
- **Billing regression.** For the FLIP program, a fixed effects billing regression model was used to estimate savings for a sample of program participants, taking into account equipment installed, seasonal fluctuations, and weather conditions.
- **Participant phone survey.** Phone surveys were conducted on a sample of FLIP (n = 200) and Custom (n = 35) participants. These surveys were used to collect feedback on the program experience for the process evaluation as well as customer and equipment information used for the impact evaluation.
- **Self-report free-ridership analysis.** A separate component of the phone survey for both the FLIP and Custom programs was a battery of questions asking what equipment would have been installed if the FortisBC program had not been available. Responses for these questions were scored and used to create an estimate of program free-ridership. The evaluation did not attempt to estimate program spillover.

- **Trade ally interviews.** Interviews were conducted with contacts provided by FortisBC (n = 8) to evaluate the effectiveness of the Program's design and delivery and remaining market potential for measures covered by the Program.

1.3 Evaluation Results

1.3.1 Impact Evaluation

Engineering Review

The engineering analysis involved conducting a desk review of project applications files for a sample of custom projects and making adjustments (if needed) to savings parameters such as operating hours, baseline conditions, and/or changes in wattages with the new equipment. The original stratified sample design called for 36 projects to be reviewed, but due to incomplete documentation on several projects only 30 were reviewed for the impact calculation. As a consequence, our relative precision is less than the original goal of "90/10", meaning that we would be 90 percent confident that the analysis results would be within 10 percent of the true population average.

After fully reviewing FortisBC's lighting analysis template used to calculate savings for the FLIP program, it was found that all of the proposed fixture and lamp types are reasonable and are not yet standard practice and should therefore be eligible for incentive. Several small errors in the spreadsheet were found, but these did not have a significant effect on the overall savings estimates. Conversations with FortisBC staff indicate that some of those errors have already been corrected in the latest versions of the spreadsheet.

In the calculation spreadsheets for the FLIP program, the annual operating hours are set at a default value of 4,000. This number is replaced by customer-specific information for each project, and our comparison of the recorded hours with the participant survey data for these same customers indicate that these values match fairly well. We do recommend that the default value be replaced with a range of operating hours by business type so that a more accurate savings calculation can be achieved in those cases where the default values need to be used.

Based on the engineering review of 30 Custom project applications, a realization rate of 102.1 percent was applied to the Custom program. Although the energy savings estimated by the program were generally found to be accurate, the lack of documentation for these projects limited the amount of review that could be performed. For the projects reviewed, information such as fixture type, wattages, operating hours, and project descriptions were often missing from the project documentation. It is recommended that a complete file be kept for all Custom projects that includes detailed information on existing equipment, installed equipment, and other factors such as operating hours. If FortisBC performs a site visit, a full site report should be included with the project file.

Billing Regression

An additional impact evaluation component was a fixed effects billing regression model for FLIP customers, which was used to estimate realized savings for these lighting projects. The model utilizes several data screens that were designed to eliminate erroneous data points and reduce some of the variation introduced across businesses (and not related to energy savings) and isolate the impact of the lighting measures. From the billing regression, a realization rate of 63.3 percent was estimated for FLIP participants.

In addition to the billing regression, we also examined information about the number of burnt out lamps that existed at the time the new lighting was installed. Field data provided by the 3rd party lighting auditor indicated that approximately 12 percent of the existing lamps replaced for FLIP participants were burnt out at the time of the energy assessment. As a consequence, the billing regression does not adequately account for savings for these customers without adjusting the savings results to account for lamp burnout. Given that lighting is typically about 40 percent of commercial load (based on 2008 US Energy Information Administration data for the Pacific Northwest), we estimate that the 12 percent burnout rate was artificially reducing the savings estimates from the FLIP billing regression by approximately 8.8 percent. This adjustment factor was added to the realization rate from the FLIP billing regression to get a gross realization rate of 72.1 percent (63.3 + 8.8). No similar adjustment is needed for the Custom program, as a billing regression was not used to estimate savings for this program.

Free-Ridership Rate

A key goal of the participant survey was to collect information needed to support the calculation of a free-ridership rate; that is, the extent to which program participants would have installed the same program-qualifying equipment or taken the same action (e.g., installed energy efficient lighting) in the absence of the program. For this evaluation, we utilized the self-report approach, which, despite its recognized shortcomings, remains a widely used and a cost-effective method for estimating net program savings.

For both Custom and FLIP customers, each project was assigned a Free-Ridership Score ranging from 0 to 1.0 based on response to phone survey questions and then weighted based on the original estimated savings values provided by FortisBC. After weighting the participant survey responses by savings, the estimated free-ridership rates are 11 percent for FLIP and 34 percent for Custom. The Net-to-Gross ratio was then calculated as 1 minus the Free-Ridership Score. For Wholesale Products, the Custom free-ridership rate was applied, as these projects are not part of the direct install FLIP program (e.g., the FLIP installation contractor does not also apply for Wholesale rebates for the same projects).

Total Program Impacts

Realized savings for each of the program components is calculated from the various analysis components discussed above. Specific calculations for each program are as follows:

- FLIP – combination of billing regression and survey free-ridership calculations
- Custom – combination of Custom application file review and survey free-ridership calculations
- Wholesale Products – combination of documentation review and survey free-ridership calculations

The combined effect of these adjustments is shown in the table below. The Original Savings (estimated by FortisBC) are multiplied by the Realization Rate to determine Gross Annual Savings. This is multiplied by the Net-to-Gross ratio determined from the phone survey data to estimate Net Annual Savings.

Net-to-Gross ratios are higher for FLIP (.89) than Custom (.66) participants, since the former would have had to come up with the full cost of their lighting retrofits in the absence of the program and therefore would have been less likely to pursue them. Similarly, large commercial customers doing customer projects often have higher free-ridership rates, as they are more likely to both understand the benefits of high efficiency measures and have the means to purchase these upgrades. These projects are also often completed as part of larger remodels, which tends to increase free-ridership rates.

Table 1: Summary of Gross and Net Energy Savings By Program

	***Original* Savings kWh**	**Gross Realization Rate (%)**	**Gross Annual Savings (kWh)**	**Weighted Net-to-Gross Ratio (1-FR)**	**Net Savings (kWh)**
FLIP	4,567,748	72.1%	3,293,346	0.89	2,931,078
Custom	7,106,503	102.1%	7,255,740	0.66	4,788,788
Wholesale Products	21,851,797	102.1%	22,310,685	0.66	14,725,052

Source: Analysis by Evergreen Economics of impact evaluation results combined with participation data provided by FortisBC.

1.3.2 Process Evaluation

Trade Ally Interviews

Interviews were conducted with eight trade ally contacts provided by FortisBC; seven of these completed the full survey, while one provided only limited responses because they considered the requested information proprietary. Most of the firms surveyed were a combination of electrical and lighting installation and maintenance contractors. The interviews were designed to elicit feedback on the Lighting Program as well as obtain perspective on the larger lighting market in the area.

Participants first learned of the FortisBC lighting program either in the last few years, or a number of years ago, through predecessor programs. Four respondents who are active in the program estimated that 70-80 percent of their lighting equipment sales in the coming year, by dollar volume, would be accounted for by equipment that receives a rebate through the FortisBC programs. Respondents reported the main reasons eligible customers are not participating in the programs are: 1) high cost of equipment; 2) lack of awareness of the program; 3) program is too complicated and 4) the economy.

Firms reported a wide range in terms of the number of business lighting projects they completed in the past year, the average value of projects, and the percentage that received Fortis BC rebates.

It appears that larger lighting contractors (those with more projects) are generally less likely to be involved in the FortisBC program. All the respondents reported that in the course of bidding, proposing or marketing business lighting projects they take steps to encourage their customers to select options that are more efficient than standard equipment available or required by code.

Responses indicate that T8 lamps are the most widely sold lighting technology, with standard T8s outselling high-performance T8s, and both sold at least twice as often as T5 fluorescent lamps, which in turn were sold more frequently than high-bay T8s or T5s. Very few customers are purchasing T12s within the past year. Likewise, standard CFL bulbs far outsold either specialty CFLs or hardwired CFL fixtures. Among other lighting types, only a single vendor reported selling more than 1,000 T1 or LED exit signs, other indoor LED lighting and occupancy sensors. All contractors said they sold fewer than 1,000 high-bay metal halide lamps and outdoor LEDs within the past year.

Trade allies were also asked to characterize the remaining market potential for each of the above lighting technologies. On average, outdoor LED lights, occupancy sensors, high performance T8s, indoor LEDs and high-bay T8s or T5s all had medium to large potential, while T5 lamps and high efficiency exit signs had medium potential. Lowest potential was seen for high-bay metal halides, specialty CFLs and T12 lamps.

When asked if there were lighting technologies that should be eligible for rebates through the FortisBC program but that currently are not covered, participants suggested T5s, more LEDs and 8 foot T8s. The fact that these technologies are, in fact, already eligible for rebates suggests a need for improved communication to contractors regarding program-qualifying equipment.

On average, trade allies were moderately satisfied with the FortisBC lighting program, with respondents noting that the rebates are adequate to secure their customer’s participation. The greatest concerns expressed were regarding the length of time to receive rebate payments.

Participant Phone Surveys

Among both Custom and FLIP participants responding to the phone surveys, a high level of satisfaction was expressed for overall service by FortisBC, the lighting programs overall and the new lighting equipment itself. When asked about their overall satisfaction with the Lighting Program, over 90% of FLIP participants provided a rating of 8 or greater on a 10-

point satisfaction scale. Similarly, over 80% of Custom participants provided an overall satisfaction rating of 8 or greater.

Participants are also generally concerned about energy efficiency at their business. Among those surveyed, 56% percent of FLIP participants and 51% of Custom participants indicated that they did ‘everything they can’ or ‘a lot’ to reduce energy costs. There was a split, however, in knowledge about energy efficiency, with a significant portion considering themselves very knowledgeable (19% FLIP, 31% Custom), while another significant group indicating that they did not know much about energy efficiency (12% for FLIP, 17% for Custom). This indicates that there is a role for the FortisBC Lighting Program in reaching these customers and educating them regarding their efficiency options.

Both FLIP and Custom participants do not have the much infrastructure to support energy efficiency, which further illustrates a need for the FortisBC program. Few businesses have staff devoted to energy efficiency (24% for FLIP, 26% for Custom) or have documented energy savings goals (15% for FLIP, 15% for Custom).

1.4 Conclusions and Recommendations

General evaluation conclusions include the following:

Participants are generally very satisfied with the program. Survey responses from both the FLIP and Custom participants indicate a high level of satisfaction, with over 80 percent of respondents rating their satisfaction as an 8 or higher on a 10-point scale.

Program measures are appropriate for rebates. Based on our review of the rebated measures, it appears that the program is providing incentives for measures with efficiency levels that are above what would be generally considered standard practice. In this regard, the program is appropriately designed and encouraging the installation of lighting that is of higher efficiency than what would normally be installed.

Net impacts consistent with similar programs. The net-to-gross ratios estimated for these programs are consistent with expectations and the Evergreen team’s experience with similar programs. For the direct install FLIP program, the estimated free ridership was relatively low as would be expected for the targeted small business market segment. For the Custom component, estimated free ridership was higher. However, large commercial customers often have higher free ridership rates as they are often more likely to understand the benefits of high efficiency measures and have the means to purchase these upgrades. These projects are also often completed as part of larger remodels, which tends to further increases free ridership rates.

Contractors report selling a mix of standard and high efficiency measures. Responses from contractors regarding sales within the previous year indicate that T8 lamps are the most widely sold lighting technology, with standard T8s outselling high-performance T8s, and both sold at least twice as often as T5 fluorescent lamps, which in turn were sold more frequently than high-bay T8s or T5s. Very few customers are purchasing T12s: only three contractors reported selling T12 lamps, and none sold more than a thousand T12s within the prior year. Standard CFLs bulbs far outsold either specialty CFLs or hardwired CFL fixtures.

Contractors suggest a wide variety of areas with remaining market potential. Remaining market potential is considered by respondents to be medium to large for outdoor LED lights, occupancy sensors, high performance T8s, indoor LEDs and high-bay T8s or T5s. Similarly, the specific technology most commonly identified as having good potential over the next two years was LED lighting.

Customers are concerned about energy efficiency but have limited internal resources. Both the FLIP and Custom participant surveys indicate that customers make energy efficiency a priority in their purchase decision and do as much as they can to reduce their energy bills. However, most do not have an internal staff member devoted to these issues and few have explicitly defined energy savings goals. Similarly, the trade ally interviews also indicate that the cost of efficiency measures is a primary barrier for their customers. Taken together, these findings indicate that customers are interested and willing to adopt energy efficient lighting, but need some assistance from FortisBC to make these installations happen.

Recommendations for program improvement are as follows:

Tracking additional project details is strongly recommended. Both FLIP and Custom projects would benefit substantially from having additional detail maintained in the program tracking system. For Custom projects, at a minimum, a simple description of the basic project should be included so it is clear what is actually being installed. For the FLIP program, the project details should include estimated savings for each individual measure installed. For both FLIP and Custom projects, additional detail on baseline assumptions should also be tracked. If a site visit is conducted, then a full site report should also be included with the project documentation.

Adjust default operating hours in the calculation spreadsheets. The program should continue to collect operating hours data from the customer whenever possible. In cases where this information is not available, however, the calculation spreadsheets should have default operating hour data by building type. This additional detail will result in more accurate estimates of project savings by tailoring the impact estimates by building or business type. The default number of 4,000 operating hours should also be adjusted downward, as this is likely too high for the average project type.

Minor issues in the FLIP calculation spreadsheet should be addressed. As discussed in the engineering review (and provided in a separate spreadsheet to FortisBC), our analysis revealed several areas for suggested revision in the FLIP savings calculation spreadsheet. These suggested corrections are relatively minor, however.

Improve application review and rebate payment times to contractors. The length of time it took to receive payments from FortisBC was a common complaint among the contractors we interviewed. Contractors also mentioned the length of time for project application review as an area of some dissatisfaction. Improvements in these areas should increase contractor satisfaction with the program.

FortisBC should incorporate interactive effects into savings calculations. Interactive effects adjustments are appropriate for HVAC and certainly for refrigerated space applications where lighting heat gain to the space is always impacting refrigeration load. By not including these interactive effects, significant amounts of energy savings are being overlooked. In the case of refrigerated space applications, this could add 30 percent or more additional savings. In non-refrigerated spaces that are heated, a lighting interaction heating penalty may be appropriate.

Attachment H3

DSM MONITORING AND EVALUATION PLAN 2013 TO 2015

DSM Monitoring and Evaluation Plan 2013 to 2015

Prepared for:
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April 22, 2013

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Section 1: Monitoring & Evaluation Plans

1 Introduction

FortisBC Inc. (FBC) developed a comprehensive approach to delivering electric demand side management (DSM) programs to meet the Provincial policy goals set forth in the 2007 BC Energy Plan and the 2010 *Clean Energy Act*. The purpose of these programs was to address the growing demand for electricity throughout British Columbia. The 2008 Amendment to the Utilities Commission Act, and the Demand-Side Measures Regulation as amended in Dec 2011, set forth more specific requirements for public utilities to develop a “plan of how the public utility intends to reduce demand by taking cost-effective demand–side measures” and to include certain programs in the DSM plan (2012 Integrated System Plan Volume 2 2012 Long Term Demand-Side Management Plan, p. 1).

This document provides a more detailed discussion of appropriate Monitoring and Evaluation (M&E) activities throughout the time period of 2013-2015. This revised plan was developed to address the specific concerns raised by the British Columbia Utilities Commission[1] regarding the scope and depth of FBC’s M&E plans. The revised plan builds on FBC’s existing plan and expands it in the following three ways:

1. Ensures that *all programs* are evaluated during the 2013-2015 program cycle;
2. Supplements the plan through targeted literature reviews which incorporated both industry best practices and provided updated information regarding measure savings estimates; and
3. Ensures that the M&E Plan will provide the foundation to develop future Requests for Proposals (RFPs) during the reporting time period.

The revised plan provides an estimated timetable for conducting these M&E activities, either using internal resources or independent third-party evaluators. These revisions ensure that FBC is on track to measure its progress towards meeting its overall DSM savings target of offsetting 50 percent of load growth by 2020.

FBC has developed a cost-effective DSM program portfolio targeting major end-uses within each customer sector. These programs summarized by customer sector are listed next:

- **Residential Programs**
  - Home Improvement Program
    - Building Envelope measures
  - New Home Program
    - EnerGuide Evaluations
    - Performance path: EnerGuide 80/85

[1] British Columbia Utilities Commission Decision, “In the Matter of FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan,” August 15, 2012, p. 134.

        - Prescriptive path: Insulation (SIP and ICF)[2]
    - ENERGY STAR Air-Source and Ground-Source Heat Pump Program
        - TLC Heat Pump Tune-up measure
    - ENERGY STAR Lighting Rebate Program
    - ENERGY STAR Appliance Rebate Program
    - On-Bill Financing – (Renovation for Efficiency Loan Program)
    - Low Income/Rental Program
        - Energy Savings Kit Program
        - Direct Installation Lighting Program

- **Commercial and Industrial Programs**
    - Building Improvement Program (BIP)
        - New Facility Assessment and Incentives Program
        - Retrofit Audit and Incentives Program
        - Building Optimization Program
    - Industrial Efficiency Program
        - Industrial Audit and Incentives Program
    - Industrial - EMIS (Energy Management Information Systems)
    - Irrigation Audit and Pump Efficiency Program
    - Commercial Lighting Program (Custom)
    - Product Rebate Program (PRP)
        - Lighting and equipment measures

1.1 Scope of M&E Activities

This Monitoring and Evaluation (M&E) plan describes the planned evaluation activities for FBC's DSM portfolio. The M&E plan is based on industry "best practices" that have been adapted to meet the particular needs associated with FBC's current DSM program portfolio.

The plan begins with a summary of the utility and provides an overview regarding the role that M&E plays in determining the overall effectiveness of its DSM program portfolio. It also provides an overview of activities that will be conducted to assess program operations throughout the planning period covering 2013-2015. It contains a description of activities by individual program, including the estimated time frame and budget. The details regarding the planned process and impact evaluations are described more fully in the following sections.

Given the importance of program participation rates, this issue will be explored extensively in interviews with program staff, contractors, and customers. The evaluations will also provide recommendations and guidance on strategies to improve overall program participation based on industry "best practices."

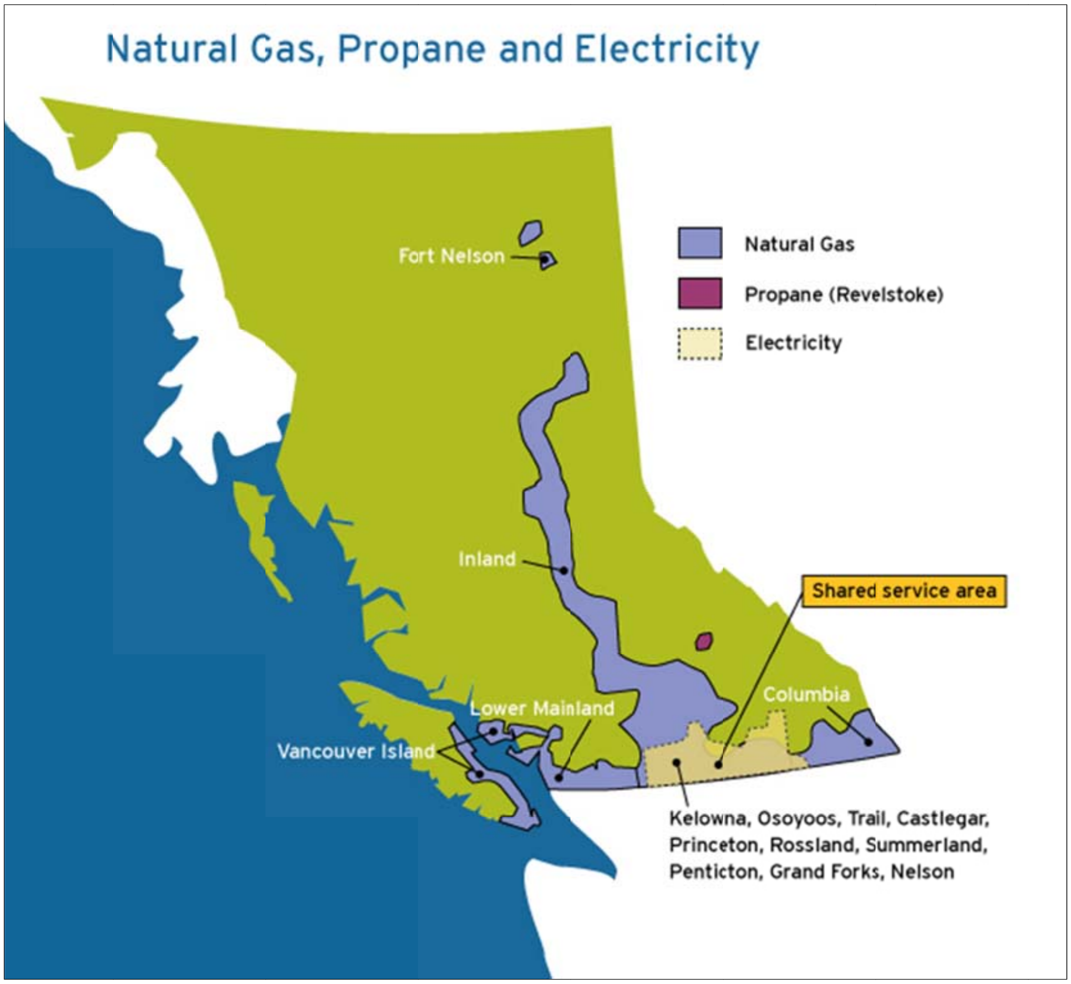
[2] Structural Insulated Panels (SIP) and Insulated Concrete Forms (ICF)

1.2 General Utility Background Information

The FortisBC Utilities, comprised of FortisBC Inc. (FBC), FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc., and FortisBC Energy (Whistler) Inc. (collectively, FortisBC) provides natural gas, electricity and piped propane, which amounts to over 21 percent of total energy consumed in BC, and serves more than 1.1 million customers in 135 communities.

FBC serves approximately 129,000 electric customers in the south central part of the province including Kelowna, Osoyoos, Castlegar, Princeton and Creston. The utility also provides service to approximately 34,000 customers through the wholesale supply of power to municipal distributors in the communities of Summerland, Penticton, Grand Forks and Nelson.

FortisBC's service territory is summarized in Figure 1.



Source: FBC website http://www.fortisbc.com/About/ServiceAreas/Pages/default.aspx

Figure 1: FortisBC's Utility Service Territory

1.3 Program Descriptions

FBC has been involved with delivering electric DSM programs since 1989. Marketed under the PowerSense^{TM} brand, the DSM programs are provided to both direct customers and those served indirectly by FBC's municipal Wholesale customers within its service territory. DSM program expenditures have escalated in the past five years, in response to customer demand and the aforementioned provincial energy policies, necessitating a commensurate increase in program evaluation activity.

This M&E plan focuses on conducting appropriate evaluation activities for the programs in FBC's PowerSense DSM portfolio.

Collaborative Programs

FBC will explore, initiate or continue partnerships in the following collaborative programs that directly support this Policy Action of the *BC Energy Plan*:

- **LiveSmart BC**: partnership with BC Hydro, FortisBC Energy Inc. and the BC Ministry of Energy, Mines and Natural Gas;
- **Appliance Take-Back** (refrigerators): partnership with retailers to co-promote the program and collect and safely dispose of (recycle) older, inefficient appliances;
- **Appliance Rebate Programs**: collaboration with BC Hydro to provide common rebates for specific high level Energy Star appliances. FBC works closely with local retailers to promote the rebate programs;
- **Energy Efficient Lighting**: arrange contracts with large retailers to provide periodic point-of-sale rebates for specialty CFL and LED lighting for residential customers;
- **Low-Income Program**: partnership with BC Hydro and FortisBC Energy Inc. to provide energy saving kits (ESK), and installation of additional energy efficiency upgrades to income qualified customers;
- **First Nations**: expand partnerships with First Nations bands to provide training for energy efficiency installations and financially support the direct installation of energy efficiency measures in qualified buildings.

Attribution of Savings from Joint Programs

FBC also undertakes and participates in integrated electricity and natural gas programs, both within the FortisBC Utilities and between the FortisBC Utilities and BC Hydro. Attributing the energy savings and carbon emission reductions that result from such projects among partner organizations needs to be fair, consistent and transparent.

FBC works with its partners to develop attribution rules for sharing the credit of energy savings appropriately among program partners and prevent double counting. Key determinants of attribution are the fuel type for space conditioning (heating/cooling) measures, and energy supplier for all other measures.

2 Evaluation Methodology

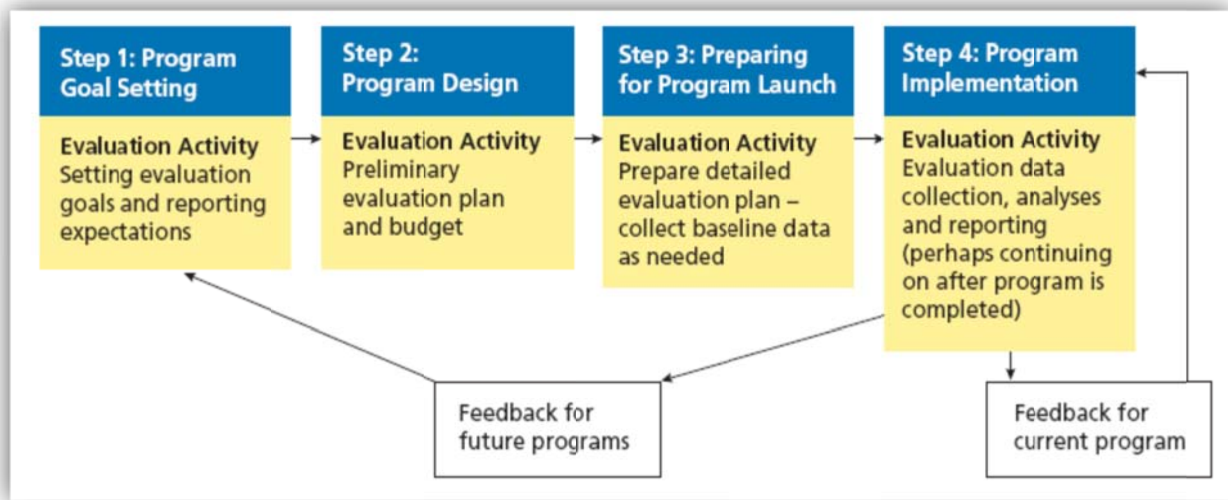
This Monitoring and Evaluation Plan incorporates the industry's "best practices" regarding the approaches to conducting comprehensive assessments of DSM programs. This section describes the role of program evaluation in relation to DSM programs, provides details on process and impact evaluations, and concludes with suggested requirements for evaluation reports. For each of these topics, we provide our recommended approaches, based on our review of FBC's current DSM program portfolio.

2.1 The Role of Program Evaluation

Program evaluation is considered a "best practice" within the energy efficiency community. Its primary functions are to:

- Quantify Results: Document and measure the energy savings of a program in order to determine how well it has met its goals, and
- Understand why program effects occurred and identify ways to improve current and future programs as well as select future programs.

The most important function of program evaluation is to provide a feedback loop that will allow for program changes and enhancements in a timely manner. This feedback loop is illustrated in Figure 2, as illustrated in the National Action Plan for Energy Efficiency (NAPEE 2007).



Source: NAPEE 2007

Figure 2: Program Evaluation Feedback Loop

Each evaluation plan developed for FBC must be tailored to meet the specific needs of a particular program. For example, some plans will describe process evaluations for year two only, while others may recommend completing process evaluations for all three years of program operations. These program evaluation plans are designed to be used as resources to help guide both the utility staff as well as inform contractors, stakeholders, and other interested parties.

2.2 Process Evaluation

A process evaluation gathers information from a variety of sources, including program staff, trade allies, program participants, and non-participants (collectively referred to as market actors). This approach, gathering data from multiple sources and then "triangulating" the data and comparing it across multiple groups, increases the validity of the findings.

Key Researchable Issues

The process evaluation for each program will document the effectiveness of the overall program focusing on the following types of activities, as applicable:

- Documenting overall customer energy efficiency cognizance, as well as awareness of the DSM program and measures,
- Verifying installations of measures through customer surveys and/or site visits,
- Assessing customer satisfaction with the program,
- Measuring free-ridership[3], and spillover[4],
- Determining if the program has led to lasting changes in customer behavior regarding energy efficiency actions, acquiring energy efficient information, or influencing customer decision-making, and
- Identifying areas for program improvement.

These issues will be explored through a number of process evaluation tasks, which are described more fully in the next section. The process evaluation activities, especially the customer surveys, will also be used to support the information required to complete the impact evaluation work, discussed in Section 2.3.

2.2.1 Process Evaluation Activities

Review Program Materials

The first step for process evaluation will be to review any program materials and relevant documents pertaining to the development and ongoing activities for each program such as:

- Current program records and documents,
- Educational and outreach materials, including website,
- Rebate application forms, and

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[3] **free-ridership:** When a consumer, who would have installed an energy efficient measure without the influence of the DSM program, participates in the program and receives a DSM incentive payment.

[4] **spillover:** When a consumer is influenced to install an energy efficient measure by the DSM program, but does not participate in the program or receive a DSM incentive payment.

- Program operational manual/program charter.

This review will include examining the various marketing activities, and reviewing the rebate application forms among any other relevant documents. This review will be conducted for all of the FBC PowerSense programs, with special attention given to the rebate applications for the equipment replacement programs.

Review Program Tracking Methods

The second critical task, which will be completed for all the programs, will be to review the database used to track and report program activities. The review will determine if the program database is adequately capturing the key metrics necessary to document installation rates for each qualifying measure; summarize these program benchmarks regarding program operations, the number of participants by measure type, region, average measure costs and estimated savings impacts. This step will also include an assessment of current tracking and reporting methods that will include recommendations for improvements.

Assess Program Flow

This task focuses on assessing the effectiveness of program operations, especially those programs that rely on processing customer rebate applications (e.g. heat pump, appliance, PRP programs). This assessment will include a careful review and explanation of the application process flow. The first step will be to review the current program flow materials developed by FBC program managers, and implementers and then compare these findings to the *actual program outcomes*. The resulting flow diagram will be based on findings from the interviews with both program staff and implementers and will provide specific recommendations for program delivery and effectiveness.

Conduct In-Depth Interviews

- **Program Staff Interviews:** These in-depth interviews will be conducted either in-person or via the telephone and will address the key process evaluation objectives regarding program operations, program-related marketing and outreach activities, customer and contractor feedback and assessment of program operations relative to overall goals. Staff interviews should be conducted with staff, administrators and implementers most familiar with all aspects of program operations—usually one to three staff members per program.
- **Trade Allies Interviews**: Surveys will be completed with a sample of trade allies, as appropriate for each program. For the new construction program, trade allies include home builders, while retailers would be the focus of in-depth interviews lighting rebate programs. Other types of trade allies targeted for these interviews include those in the heating, ventilation, and air conditioning (HVAC) market offering services to residential, commercial and industrial customers.

  These interviews will be used to identify the overall effectiveness of program operations, customer and contractor satisfaction, and barriers to participation for both the residential and commercial programs. They will also determine the market effects and assess increases in overall program awareness among these trade allies, free-ridership, spillover and measure persistence. The non-participant surveys, which should be conducted as appropriate, will assess overall program awareness, and barriers to participation. Both surveys will collect demographic information from residential customers and operational characteristics from commercial customers to help determine program impacts.

Some contractors may participate in multiple programs, such as the HVAC contractors serving both the heating and cooling markets. As a way to minimize evaluation costs, we recommend conducting 5 to 15 interviews with each type of trade ally group who currently participate in these programs. Table 1 summarizes our recommended approach for conducting trade ally interviews the selected programs.

Table 1: Recommended Sample Sizes for the Trade Ally Surveys by FBC Residential Programs

Estimated Sample Sizes	**Contractor/ Retailer/ Builder Interviews**	
Residential Programs	**Participating**	**Non-Participating**
Home Improvement Program (Retrofit)	5-10	3-5
New Home Program - EnerGuide 80/85	5-10	3-5
ENERGY STAR Air-Source and Ground-Source Heat Pump Program	10-15	3-5
TLC Heat Pump Tune-up Program	5-10	3-5
ENERGY STAR Lighting Rebate Program	5-10	3-5
ENERGY STAR Appliance Rebate Program	5-10	3-5
Low Income Direct Installation Lighting Program	3-5	3-5
Total	38-70	21-35

Table 2: Recommended Sample Sizes for the Trade Ally Surveys by FBC Commercial and Industrial Programs

Estimated Sample Sizes	**Contractor/ Retailer Interviews**	
Commercial and Industrial Programs	**Participating**	**Non-Participating**
Building Improvement Program – New and Retrofit	5-10	3-5
Industrial Efficiency Program	3-5	3-5
Commercial Lighting Program (Custom)	3-5	3-5
Product Rebate Program (PRP)	5-10	3-5
Total	16-30	12-20

Surveys

The survey efforts will be coordinated and monitored to avoid over-sampling a specific group or sub-group. Although it is possible for FBC customers to participate in multiple programs, we recommend conducting separate customer surveys for each program. In cases of participation in multiple programs, we recommend focusing survey efforts only on the most-recently completed activity. The survey instrument should be standardized to the extent possible to facilitate comparison among and between respondent groups, especially for demographic, awareness, and customer satisfaction questions.

For those programs where the participation rates are low, such as On-Bill Financing or Irrigation Pump Efficiency Program, the surveys will focus on program drop-outs instead of program participants to identify program barriers and areas for program improvement.

Table 3: Recommended Sample Sizes for the Customer Surveys

<table>
<tr><th>FBC PowerSense Programs</th><th>Participating Customers</th><th>Non-Participating Customers</th></tr>
<tr><td>Residential Programs</td><td></td><td rowspan="10">50-100</td></tr>
<tr><td>Home Improvement Program (Retrofit)</td><td>30-50</td></tr>
<tr><td>New Home Program - EnerGuide 80/85</td><td>30-50</td></tr>
<tr><td>ENERGY STAR Air-Source and Ground-Source Heat Pump Program</td><td>50-100</td></tr>
<tr><td>TLC Heat Pump Tune-up Program</td><td>50-100</td></tr>
<tr><td>ENERGY STAR Lighting Rebate Program</td><td>50-100</td></tr>
<tr><td>ENERGY STAR Appliance Rebate Program</td><td>50-100</td></tr>
<tr><td>On-Bill Financing Program</td><td>10-20</td></tr>
<tr><td>Low Income Energy Savings Kit</td><td>30-50</td></tr>
<tr><td>Low Income Direct Installation Lighting Program</td><td>30-50</td></tr>
<tr><td>Commercial and Industrial Programs</td><td rowspan="5">NA</td><td rowspan="7">50-100</td></tr>
<tr><td>Building Improvement Program – New and Retrofit</td></tr>
<tr><td>Industrial Efficiency Program</td></tr>
<tr><td>Industrial - EMIS (Energy Management Information Systems)</td></tr>
<tr><td>Irrigation Pump Efficiency Program</td></tr>
<tr><td>Commercial Lighting Program (Custom)</td><td>10-20</td></tr>
<tr><td>Product Rebate Program (PRP)</td><td>30-50</td></tr>
</table>

Case Studies

As a way to provide additional insight into the challenges associated with reaching industrial customers, instead of conducting customer surveys, we recommend conducting on-site surveys that would include in-depth interviews with key decision-makers regarding the selection, installation, and overall satisfaction with the installed measures. These case studies, targeting customers participating in selected commercial and industrial programs with limited participation, will provide valuable insights regarding customer awareness, barriers to program participation, and customer satisfaction. These findings can also be used as testimonials as a way to encourage similar businesses to participate in these FBC programs in the future.

A case study approach with site visits could also be used, in large scale residential programs, to supplement the information gathered via survey methods. For example a sub-set of air-source heat pump customer sites were visited, in addition to the numerous participant phone surveys conducted, in the 2009 Heat Pump evaluation report.

The case study interview guide will address the customers' assessment of program operations, satisfaction with the contractor, and FBC staff as well as questions to determine program effects regarding free-ridership, spillover, measure persistence, and areas for improvement. This approach is a highly cost-effective and insightful methodology to provide program feedback for small, low-volume programs and in high-volume programs where participation is lower than anticipated.

Case studies can also include billing and (where available) sub-metering data for each customer project reviewed. The comparison of this data for energy and demand use before the measure installation to that after the measure is installed is likely to help identify savings achieved. Combining this information with data from customer interviews as well as details on the project will enable the evaluators to estimate project realization rates (and sometimes measure realization rates). Due to the qualitative nature of case studies, it is not appropriate to apply realization rates based on these activities across all projects. Rather, they can be helpful to inform ongoing estimates of similar savings and to inform program design.

Summary of Process Evaluation Activities

Tables 4 and 5 summarize the recommended process evaluation activities by program for the residential and commercial and industrial sectors. As these tables show, every program will receive some type of process evaluation activity throughout this program cycle. However, the mix of process evaluation activities is determined by a number of critical factors including participation rates, program duration, and overall program objectives.

Table 4: Summary of Process Evaluation Activities for Residential Programs

FBC Programs	Document Review	Tracking Database Review	Staff/ Implementation Interviews	Contractor Interviews/ Retailer	Customer Surveys/ Interviews
Residential Programs					
Home Improvement Program (Retrofit)	□	□	□	□	□
New Home Program - EnerGuide 80/85	□	□	□	□	□
ENERGY STAR Air-Source and Ground-Source Heat Pump Program	□	□	□	□	□
TLC Heat Pump Tune-up Program	□	□	□	□	□
ENERGY STAR Lighting Rebate Program	□	□	□	□	□
ENERGY STAR Appliance Rebate Program	□	□	□	□	□
On Bill Financing Program	□	□	□	□	□
Low Income Energy Savings Kit	□	□	□		□
Low Income Direct Installation Lighting Program	□	□	□	□	□

Table 5: Summary of Process Evaluation Activities for Commercial and Industrial Programs

FBC Programs	Document Review	Tracking Database Review	Staff/ Implementation Interviews	Contractor Interviews/ Retailer	Customer Surveys/ Interviews
Commercial and Industrial Programs					
Building Improvement Program–New and Retrofit	□	□	□	□	□
Industrial Efficiency Program	□	□	□	□	□
Industrial - EMIS	□	□	□		□
Irrigation Pump Efficiency Program	□	□	□	□	□
Commercial Lighting Program (Custom)	□	□	□	□	□
Product Rebate Program (PRP)	□	□	□	□	□

2.3 Impact Evaluation Plan

FBC has already taken a reasonable approach to conducting impact evaluation as part of planned comprehensive evaluations. We reviewed evaluation reports recently prepared for the company and found them to be both thorough and adhere to evaluation industry best practice. Impact evaluation is devoted to quantifying the effects of programs.

Key Researchable Issues

- The peak kW and annual GWh savings achieved by the participants
- The portion of total savings that are attributable to the program

For each program, evaluators conduct three central tasks: assemble data, estimate total participant savings, and estimate net program savings. The next section describes how to conduct impact evaluation tasks on a step-by-step basis.

2.3.1 Impact Evaluation Activities

Assemble Data to Conduct the Impact Analysis

The first step for impact analysis is to support whichever technique will be used to estimate the program savings. This includes reviewing program activity, savings calculations, and billing data from FBC and coordination with the process evaluation to ensure survey data needed from participating and/or non-participating customers/market actors is procured during the process evaluation data collection. These survey data include information about additional activities taken outside the program and information about the role the program played in their decision to take actions within the program (to estimate free-ridership and spillover).

Estimate Gross kW and kWh Savings Achieved by Program Participants.

The technique(s) appropriate for conducting this analysis varies somewhat by program. We briefly describe the alternatives here and the implications of choosing them.

- **Engineering calculations for a sample of projects.** This starts with designing a sample frame to select a statistically representative sample of projects to meet statistical precision and confidence level requirements, for example +/- 15% precision at the 85% confidence level. These calculations can be informed by results of field visits and site metering but it is not always required. The task includes examining aspects of ex-ante savings calculations to confirm/adjust number of installations recorded and/or per-unit savings. Adjusted or realized savings are represented as the number of confirmed measures implemented multiplied by realized per-unit savings. Evaluators check appropriate use of deemed values and/or formulas and calibrate values and/or formulas based on assumptions researched through study or secondary data (e.g., facility hours of operation) and/or data collected in participant surveys, field verifications, and/or metering. By assessing and adjusting components of savings values in the sample, evaluators develop sample realization rates and apply them to the population of program participants to obtain adjusted (realized) gross program-level savings. We recommend that FBC consider the following approaches:

  - *Limited Engineering Review*. The assessment only reviews data from the tracking system and additional documentation to substantiate measure installations and specifications. This is acceptable for measures with well-established and vetted deemed savings that vary little.
  - *Option A of the International Performance Measurement and Verification Protocol (IPMVP) Standards*. This option includes data from survey, project-specific data in files, relevant secondary data, and/or spot metering (IPMVP Protocols, 2010).
  - *Option B of the IPMVP standards*. This option includes metered data of actual energy use or factors that proxy energy use, such as elapsed time metering (data loggers).

- **Econometric methods and modeling.** These are more sophisticated and expensive methods to apply under specific conditions, for example, when data is available for an adequate length of time, measure savings account for at least 10% of energy use, enough participants install measures, or there is no baseline available for comparison.
  - *Statistical Billing Analysis and Statistically Adjusted Engineering (SAE) Models*. SAE models use statistical regression analysis to assess changes in energy use associated with installing various measures. This approach is data intensive, though essential information is generally maintained for the necessary pre- and post-periods by the utility (kWh and/or kW billing data); supplementary customer data can be collected using surveys. A billing analysis model can generate savings estimates directly using indicators for the presence of a particular measure in the model. An SAE model uses the same framework but uses ex-ante deemed or engineering estimates to produce a “realization” rate which is applied to ex-ante savings to estimate ex-post program savings. This approach satisfies Option C of the IPMVP Standards.
  - *Energy Simulation Modeling*. Using secondary data or actual inputs from specific sites, characteristics about the building such as square footage, and usage such as operating hours, the model simulates energy use under different conditions (e.g., baseline, post-installation of measure) to estimate measure savings. Models can be calibrated to actual energy use in the building if these data are available. Modeling is most useful when there is no “pre” program data, such as new construction situations or “one-off” projects such as in custom measure programs. The evaluator defines a prototype of each building type represented by participants in the sample, which are inputs for a model that calculates energy use for each hour of the day and year. From the simulations, energy savings and peak load impacts are calculated by comparing a simulation of participant buildings with that of the prototype building. This approach satisfies Option D of the IPMVP Standards.

- **Other methods.** For programs with limited budgets, low participation rates, and/or very diverse projects, other evaluation methods are more appropriate.

- *Case Studies.* Case studies focus on a small number of projects from a program, gather in-depth information, and assess savings impacts, motivation and influences, and process-related experiences. Case studies can employ any of the methods described above, so as to still meet the IPMVP measurement standards. (See Section 2.2.1 for a more detailed discussion regarding case studies.)
- *Savings Accounting.* This is a review of savings a utility reports to provide a more detailed examination of those savings; for example, by subsector or by measure type. This does not produce verified savings but helps determine which measures are most/least effective in helping reach savings goals, and can identify inconsistencies or errors in program tracking data. Realization and net-to-gross (NTG) rates from secondary sources or other programs/years are applied to reported savings, if available and as necessary.

Estimate Net Program Impacts.

This analysis estimates both free-ridership and spillover in the program, resulting in a NTG ratio applied to total kW and kWh savings estimated to calculate net program savings. Three approaches are used, with the first two survey-based methods most commonly used and well accepted in the industry.

- **Customer only NTG:** In the data collection, a battery of questions about the influence of the program on actions taken and the timing of those actions are used to estimate free-ridership and participant spillover. Obtaining responses from non-participants allows estimation of non-participant spillover as well. This is least expensive but tends to yield the lowest net impacts (i.e., highest estimate of free riders), mostly because customers typically overestimate the likelihood that they would have taken the action without the program.
- **Customer and market actor NTG (also referred to as enhanced NTG):** This approach is similar to the "customer only" one but additionally asks similar questions to the vendors, contractors, etc. who work with customers and/or influence decisions. This costs more but results from studies show that this approach attributes higher savings to the program (i.e., lower estimate of free riders). It seems that information from vendors and contractors adds a reality check on customers' responses. This is the approach we recommend most—it provides both free-ridership and spillover estimates and at the most reasonable cost.
- **Discrete choice analysis NTG:** This uses data on customer characteristics, actual choices, and attitudes to statistically estimate free-ridership. Requiring in-depth customer surveys and billing data, it is the most expensive approach but has historically yielded the highest estimate of net savings as it accounts for the many factors driving decision making. Discrete choice analysis is considered the gold standard in the industry.

Some programs do not have direct impacts on savings and therefore do not need a full impact evaluation. These are shown in Table 6.

Table 6: Programs or Program Components with No Direct Impact

Sector	Programs/Program Components	Evaluation Activities
Residential	Reduce Your Use	Track # of audits - address in surveys
	On Bill Financing Program	Low participation - track opportunities and applications, and address in surveys/interviews
Commercial and Industrial	Retrofit audits and industrial audits	Track # of audits by customer type
	New facility assessment	Track # of assessments

Residential Programs Impact Evaluations

Table 7 reflects the impact evaluations recommended for the residential sector. As with the commercial and industrial sector, all programs will have some form of impact assessment over the program cycle.

Table 7: Residential Impact Evaluation

Residential Programs	Timing	Suggested Approach(es)
Home Improvement Program	2014 2015	Review ex-ante[5] estimates compared to those in other jurisdictions. Engineering review of a sample of projects. [6]
New Home Program	2014	Simulation modeling for a sample of homes.
ENERGY STAR Air Source and Ground Source Heat Pumps	2013	Review ex-ante estimates compared to those in other jurisdictions. Simulation modeling for a sample of homes.
ENERGY STAR Lighting and Appliances Rebate Programs	2013 2015	Review of ex-ante savings from other jurisdictions. Assess market impact based on REUS data and other sources such as survey and/or market data.
Low Income/Rental Program Direct Installation Lighting Program	2013 2015	Review ex-ante estimates for energy savings kits and compare to those in other jurisdictions. Conduct engineering review of sample of direct installation projects with on-sites. Conduct a billing analysis.

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[5] **ex ante:** As viewed in advance. The ex ante value of a variable is what the person or organization responsible expects it to be. Ex ante is contrasted with ex post, meaning as viewed after the event. **ex post:** The value of a variable as it appears after the event, that is, what actually occurred. Ex post is contrasted with ex ante, which means looking at things before the event.

[6] Will compliment LivingSmart BC Evaluation if needed.

Commercial and Industrial Program Impact Evaluations

Table 8 reflects impact evaluations that we recommend between 2012 and 2015, along with suggested approaches. This ensures the impacts of all programs in the sector are reviewed in the program cycle.

Table 8: Commercial and Industrial Impact Evaluation

Commercial and Industrial Programs	Timing	Suggested Approach(es)
Building Improvement Program - New and Retrofit	2014	Billing analysis, engineering review with on-sites, building simulation models.
Industrial Efficiency Program	2015	Engineering review of a sample of projects with on-sites. Case studies.
Industrial EMIS	2015	Case studies of 2-3 projects with on-site visits.
Irrigation Pump Efficiency Program	2015	Pilot program that will include measurement and verification at the project level.
Commercial Lighting Program	2014	Engineering review of a sample of projects. Literature review of hours of use by sub-sector.
Product Rebate Program	2015	Review of ex-ante estimates (secondary research) and engineering review of a sample of projects.

2.4 Suggested Requirements for Draft and Final Reports

The draft and final reports for each program year should include the following sections. FBC staff will have a minimum of two weeks to review the draft report before it is finalized.

E: Executive Summary

1. Introduction
    - 1.1 Program Overview
    - 1.2 Program Objectives
2. Evaluation Plan
    - 2.1 Research Issues and Objectives
    - 2.2 Description of Evaluation Efforts
    - 2.3 Data Collection Plan
3. Process Evaluation Results
    - 3.1 Findings
    - 3.2 Recommendations
4. Impact Evaluation Results
    - 4.1 Findings
    - 4.2 Recommendations

3 Proposed Schedule

The proposed timing for completing the Process and Impact Evaluations is summarized in Table 9. However, these activities may be adjusted based on available data, research needs, and staffing and resource constraints.

Table 9: Proposed Schedule for Process and Impact Evaluations

	2013	2014	2015
RESIDENTIAL PROGRAMS			
Home Improvement Program (Retrofit)			
New Home Program - EnerGuide 80/85			
ENERGY STAR air-source heat pump, ENERGY STAR split ductless air-source heat pump and Geo-exchange heating system			
ENERGY STAR TLC air-source and ground source heat pump Tune-up			
ENERGY STAR Lighting Rebate Program			
ENERGY STAR Appliance Rebate Program			
On Bill Loan Financing			
Low Income Energy Savings Kit			
Low Income Direct Installation Lighting Program			
COMMERCIAL and INDUSTRIAL PROGRAMS			
Building Improvement Program – New and Retrofit			
Industrial Efficiency Program			Case Studies
Industrial - EMIS (Energy Management Information Systems)			Case Studies
Irrigation Pump Efficiency Program			Case Studies
Commercial Lighting Program (Custom)			
Product Rebate Program			
Municipal Program			
Behavioural Program			

Legend

Process Activities	
Impact Activities	
Market Activities	
Combined	

4 Evaluation Budget

4.1 Process Activities

Table 10 summarizes our estimated costs for the additional process evaluation activities recommended in this report. These costs are in addition to those budgeted for comprehensive impact studies.

Table 10: Summary of Budgets for 2013-2015

Summary of Estimated Process Evaluation Costs during the 2013-2015 Program Cycle	Low Estimate	High Estimate
Estimated Number of Programs	15	20
Estimated Process Evaluation Hours per program per program cycle	25	35
Average Hourly Rate	$150	$150
Cost per program during the program cycle	$3,750	$5,250
Estimated Cost over the 3-year evaluation plan cycle?	$56,250	$105,000

Table 11: Estimated Costs by Activity for 2013-2015

Summary of Process Evaluation Budgets	Low Estimate	High Estimate
Process Evaluation Activities	$56,250	$105,000
Data Collection Activities	$19,660	$38,750
Additional Utility Management Costs	$13,000	$19,500
Estimated Total Additional Process Evaluation Costs during the 2013-2015 Program Cycle	$90,000	$164,000
Additional Process Evaluation Costs Per Annum	**$30,000**	**$55,000**

4.2 Budget Implications

FBC currently budgets approximately $370,000 per annum for Monitoring and Evaluation, including internal staffing and external comprehensive M&E reports.

The proposed additional process evaluation activities will incrementally increase the total budget. The estimated range of the increased costs is between $30,237 and $55,417 per annum. Therefore the resulting total budget requirements will be between $400,000 and $425,000 per annum.

4.3 Resource Requirements

FBC staff may conduct many of the proposed process evaluation activities internally, to the extent that internal resources are available. Specifically, the FBC staff can conduct the in-depth interviews, design the customer surveys, and review internal documents and program processes. FBC may need to rely on external resources to complete the interviews with FBC staff, specialized interviews with contractors, case studies and the fielding and analysis of customer surveys.

Preparing the comprehensive M&E reports, incorporating process, market and impact studies, should continue to be performed by third-party consultants with the appropriate expertise in this field.

5 References

British Columbia Utilities Commission Decision, "*In the Matter of FortisBC Inc. 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan,*" August 15, 2012, p. 134.

FBC website http://www.fortisbc.com/About/ServiceAreas/Pages/default.aspx <Accessed February 12, 2013>

FBC 2012 Integrated System Plan Volume 2 2012 Long Term Demand-Side Management Plan, pp. 1.

International Performance Measurement and Verification Protocol, 2010. http://www.evo-world.org/

National Action Plan for Energy Efficiency, 2007. *Model Energy Efficiency Program Impact Evaluation Guide*, November, Department of Energy, Washington D.C. http://www.epa.gov/cleanenergy/documents/suca/evaluation_guide.pdf

Stanski, H, 2011, *Heating and Cooling Degree Days* Strata KAS2464 Kelowna, Comments and Information Request Number 2, regarding the FBC RIB Application.

Attachment H4

LRMC AVOIDED COST DERIVATION

BC Market Levelized Price

	Nominal Levelized Price	Real Levelized Price (2013$)	Inflation
Number of Periods	30	30	
Nominal Discount Rate	8.2%	6.0%	2.1%
NPV	$623.99	$623.99	
Levelized Price	**$56.61**	**$45.33**	

Year	BC Market Cost Curve (Nominal $) Market Scenarion C: Low Carbon, Low-Gas[1]	BC Market Cost Curve (Real $2013) Market Scenarion C: Low Carbon, Low-Gas[2]	Escalator
2014	$36.92	$36.16	1.021
2015	$41.43	$39.75	1.042
2016	$45.97	$43.19	1.064
2017	$48.42	$44.56	1.087
2018	$52.03	$46.89	1.110
2019	$53.30	$47.05	1.133
2020	$55.23	$47.75	1.157
2021	$51.60	$43.69	1.181
2022	$52.71	$43.72	1.206
2023	$54.17	$44.01	1.231
2024	$55.34	$44.03	1.257
2025	$57.57	$44.87	1.283
2026	$59.52	$45.43	1.310
2027	$61.17	$45.73	1.338
2028	$62.85	$46.02	1.366
2029	$65.15	$46.72	1.394
2030	$67.13	$47.15	1.424
2031	$68.97	$47.45	1.454
2032	$70.99	$47.83	1.484
2033	$73.11	$48.25	1.515
2034	$75.29	$48.66	1.547
2035	$77.53	$49.08	1.580
2036	$79.82	$49.49	1.613
2037	$82.19	$49.91	1.647
2038	$84.61	$50.33	1.681
2039	$87.10	$50.74	1.717
2040	$89.66	$51.16	1.753
2041	$92.29	$51.58	1.789
2042	$94.99	$51.99	1.827
2043	$97.77	$52.41	1.865

[1] Source: FortisBC 2012 Long Term Resource Plan, Appendix B, Table 5.1.3.3-A

[2] Source: BC Hydro 2011 LTAP Technical Advisory Committee, Electric Price Forecast - Low Gas Low Carbon Scenario C

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MEMORANDUM

To: Ron Zeilstra, FortisBC

From: Midgard Consulting

Date: 15 June 2013

Subject: Derivation of the British Columbia Electricity Price Forecast 2014 to 2043

The memorandum outlines the methodology to generate the price of electricity within the British Columbia market, for the years 2014 through 2043.

Overview

Although there are transparent and liquid electricity markets in jurisdictions that neighbour British Columbia (namely the Alberta Electricity Market, and the much larger Mid-Columbia Electricity Market), there is no transparent or liquid electricity market in British Columbia.

Nonetheless, future electricity prices in British Columbia can be forecast based upon a forecast price for electricity originating from the Mid-Columbia (or Mid-C) trading hub and delivered to the British Columbian border.

Given that there is limited visibility and liquidity for Mid-C electricity prices in the long term (i.e. more than 5 years from today), the 30 year forecast (2014 through 2043) was based upon the forecast cost of natural gas in future years. Given the prominent role that natural gas prices play in determining the marginal cost of generating electricity in most WECC jurisdictions, the expected cost of electricity in the future is forecast to be closely associated with the expected cost of natural gas during those same time periods.

Step-by-Step Methodology – Based on GLJ Baseline Natural Gas Prices

Step 1a – Obtain Natural Gas Baseline Annual Price (GLJ baseline natural gas prices) – Column B

- The natural gas forecast price (Henry Hub, real dollars) from the website of GLJ Petroleum Consultants (http://www.glja.com/commodity-price-library; JAN 2013 version) are used as the starting point. This natural gas price forecast is consistent with the one used in other recent FortisBC regulatory filings.
- The natural gas price is quoted in real U$2013/MMBtu. The GLJ price forecast runs from 2014 through 2023. The price average from 2018 through 2023 (which is constant at $5.25/MMBtu) is continued for the years 2024 through 2043 (i.e. $5.25/MMBtu).
- The resulting Henry Hub natural gas price forecast is titled the Henry Hub within the spreadsheet *(Column B)*.

<u>Step 2a – Derive Heat Rates (MMBtu to MWh energy conversion ratio) – Column E and F</u>

- Historic pricing data from the Intercontinental Exchange (ICE)[1] is used to derive the historic heat rate (ratio of cost of electricity over cost of natural gas) between Henry Hub natural gas prices and Mid-C day-ahead electricity prices. The data examined ran from April 2013 (the latest available data at the time of the analysis) back to 2002. This heat rate data is used to calculate representative heat rates that can be applied to high load hours (or HLH, also known as on-peak hours) and low load hours (or LLH, also known as off-peak hours) going into the future *(Column E and F)*.
- All data are quoted in actual prices (U$/MMBtu for the natural gas prices and U$/MWh for the electricity prices).
- The heat rates witnessed over the past decade experienced periods of extremes from year to year, and clear seasonal patterns (e.g. low heat rates during the freshet period), however the overall annual averages display solid correlations between the respective natural gas and electricity prices. The resulting average heat rates are a good predictor of expected future heat rates.
- Midgard examined the correlations between Mid-C prices and Henry Hub natural gas prices. The Henry Hub - Mid-C correlations are very high. Midgard employed the Henry Hub natural gas price forecast as the basis of calculating the long term Mid-C electricity price because the Henry Hub curve is the predominant natural gas price benchmark in North America. Historic data and price forecasts for Henry Hub natural gas are readily available.

<u>Step 3a – Generate Mid-C Electricity Forecast – Column G, H and I</u>

- The Henry Hub price forecast (from Step 1a) is multiplied by the heat rates calculated in Step 2a in order to derive a Mid-Columbia electricity price forecast.
- The Mid-C electricity price forecast calculations were made for both HLH and LLH *(Column G and H)*. [2]
- The Mid-C "All-Hours" electricity price is a weighted average of the HLH and LLH prices *(Column I)*.
    - Midgard assumed that the high load hours equate to 16 hours per day for 6 days per week for 52 weeks per year minus 12 holidays, or 4800 hours per year
        - HLH=55% of all hours (4800 of 8760 h/yr), the remaining are LLH = 45% of all hours
        - The ratios (i.e. weightings) are used in the deriving of the all-hours electricity price

<u>Step 4a – Translate Mid-C Price Forecast to BC Price Forecast – Column Q</u>

- The Midgard BC Electricity price forecast shadows the cost that FortisBC would face if they were to purchase electricity at Mid-C and wheel the power to the Canada-US border; Midgard has assumed that FortisBC pricing would not be required to be wheeled through the BC Hydro grid, and hence attract additional wheeling and system losses costs that would further raise the electricity price.

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[1] www.theice.com

[2] Midgard also examined the Sunday 1x16 pricing, however that data set was smaller than the on-peak and off-peak data sets, and produced results that were more volatile (i.e. statistically less reliable) than the results of the other two data sets. Consequently, Midgard opted to use only the on-peak and off-peak derived heat rates to calculate the Mid-C price forecast for electricity (treating the Sunday 1x16 as an off-peak period).

- The forecast is not meant to represent the cost of importing power, but rather a proxy for the average price of electricity within the British Colombian context.
- The following factors are applied to translate the Mid-C price forecast to the BC context (i.e. to the Canadian border):
  1. Account for the price difference between high and low load hours *(Column I)*
  2. Include a GHG (or carbon) adder to the price of electricity *(Column J)*
  3. Account for cost of transmitting the electricity from Mid-C to the Canadian border, including Bonneville Power Administration (BPA) wheeling rates[3] *(Column N)*, and transmission line losses[4] *(Column O)*.
  4. $USD:$CDN exchange rate *(Column P).*
- The resulting Expected FortisBC price is in real 2013 Canadian dollars per megawatt hour *(Column Q)*.

Miscellaneous Cost Factors

- The expected impacts that greenhouse gas (GHG) regulations will have upon electricity prices in the British Columbian context were determined as follows.
  - GHG calculation is based upon work performed by Black & Veatch for the BC Hydro for use within their current (2012/2013) Integrated Resource Plan. The information is publicly available.
  - The report contains several scenario forecasts, including a low GHG price adder. Midgard feels that the low GHG price adder scenario is the most plausible scenario, and therefore used those prices within this exercise *(Column J)*.
- The BPA wheeling rate for 2014 is calculated as $1.917 USD/MWh. The transmission losses used are 1.90% of the expected Mid-C price (including the wheeling charges) *(Column N).*
  - Midgard assumed that the costs of wheeling power would increase by 1% per annum in real terms, which is a proxy for the additional costs of congestion as well as infrastructure additions within the region.
- The foreign exchange assumption used to transform $USD/MWh into $CAD/MWh is 1:1; this assumption is derived from the GLJ January 2013 forecast (http://www.glja.com/commodity-price-forecasts; JAN2013 version) *(Column P).*
- The Midgard BC Electricity forecast is presented both in real 2013 $CAD/MWh as well as nominal $CAD/MWh.
  - Apply a 2.1% annual inflation rate *(Column U)* to convert real dollar values ($2013CAD) to nominal dollars ($CAD) *(Column R)*.

[3] BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summary

[4] BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation"

Year	Expected[A]	Heat Rate[B]		HLH Expected[C]	LLH Expected[C]	All-Hours Expected[C]	Expected	HLH Expected w GHG	LLH Expected w GHG	All-Hours Expected w GHG	BPA Tx Wheeling[E]	Losses[F]	Exchange[G]	Expected Fortis BC	Expected Fortis BC
	Henry Hub	HLH	LLH	MID-C	MID-C	MID-C	GHG Adder[D]	MID-C w GHG+	MID-C w GHG+	MID-C w GHG+	"Congestion+" (USD/MWh)	Losses (USD/MWh)	FX	"FBC" Electricity	"FBC" Electricity
	2013 $$	n/a	n/a	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	2013 $$	n/a	2013 $$	Current
	USD/MMBtu	MMBtu/MWh	MMBtu/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	USD/MWh	1.00%	1.90%	CAD/USD	CAD/MWh	CAD/MWh
2014	$4.17	7.9	6.1	$32.94	$25.44	$29.57	$4.00	$36.94	$29.44	**$33.57**	$1.917	$0.674	$1.00	**$36.16**	**$36.92**
2015	$4.57	7.9	6.1	$36.10	$27.88	$32.40	$4.67	$40.77	$32.55	**$37.07**	$1.936	$0.741	$1.000	**$39.75**	**$41.43**
2016	$4.95	7.9	6.1	$39.11	$30.20	$35.10	$5.34	$44.44	$35.53	**$40.43**	$1.956	$0.805	$1.000	**$43.19**	**$45.97**
2017	$5.08	7.9	6.1	$40.13	$30.99	$36.02	$5.74	$45.87	$36.72	**$41.75**	$1.975	$0.831	$1.000	**$44.56**	**$48.42**
2018	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.80	$48.28	$38.83	**$44.03**	$1.995	$0.874	$1.000	**$46.89**	**$52.03**
2019	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.94	$48.41	$38.96	**$44.16**	$2.015	$0.877	$1.000	**$47.05**	**$53.30**
2020	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.60	$49.08	$39.63	**$44.83**	$2.035	$0.890	$1.000	**$47.75**	**$55.23**
2021	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.60	$45.08	$35.63	**$40.82**	$2.055	$0.815	$1.000	**$43.69**	**$51.60**
2022	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.60	$45.08	$35.63	**$40.82**	$2.076	$0.815	$1.000	**$43.72**	**$52.71**
2023	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.87	$45.34	$35.89	**$41.09**	$2.097	$0.821	$1.000	**$44.01**	**$54.17**
2024	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$3.87	$45.34	$35.89	**$41.09**	$2.118	$0.821	$1.000	**$44.03**	**$55.34**
2025	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$4.67	$46.14	$36.69	**$41.89**	$2.139	$0.837	$1.000	**$44.87**	**$57.57**
2026	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.20	$46.68	$37.23	**$42.42**	$2.160	$0.847	$1.000	**$45.43**	**$59.52**
2027	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.47	$46.94	$37.49	**$42.69**	$2.182	$0.853	$1.000	**$45.73**	**$61.17**
2028	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$5.74	$47.21	$37.76	**$42.96**	$2.204	$0.858	$1.000	**$46.02**	**$62.85**
2029	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.40	$47.88	$38.43	**$43.63**	$2.226	$0.871	$1.000	**$46.72**	**$65.15**
2030	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$6.80	$48.28	$38.83	**$44.03**	$2.248	$0.879	$1.000	**$47.15**	**$67.13**
2031	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.07	$48.55	$39.10	**$44.29**	$2.270	$0.885	$1.000	**$47.45**	**$68.97**
2032	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.42	$48.90	$39.45	**$44.65**	$2.293	$0.892	$1.000	**$47.83**	**$70.99**
2033	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$7.81	$49.28	$39.83	**$45.03**	$2.316	$0.900	$1.000	**$48.25**	**$73.11**
2034	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.19	$49.67	$40.22	**$45.42**	$2.339	$0.907	$1.000	**$48.66**	**$75.29**
2035	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.58	$50.05	$40.60	**$45.80**	$2.362	$0.915	$1.000	**$49.08**	**$77.53**
2036	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$8.96	$50.44	$40.99	**$46.18**	$2.386	$0.923	$1.000	**$49.49**	**$79.82**
2037	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$9.35	$50.82	$41.37	**$46.57**	$2.410	$0.931	$1.000	**$49.91**	**$82.19**
2038	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$9.73	$51.21	$41.76	**$46.95**	$2.434	$0.938	$1.000	**$50.33**	**$84.61**
2039	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.12	$51.59	$42.14	**$47.34**	$2.458	$0.946	$1.000	**$50.74**	**$87.10**
2040	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.50	$51.97	$42.52	**$47.72**	$2.483	$0.954	$1.000	**$51.16**	**$89.66**
2041	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$10.88	$52.36	$42.91	**$48.11**	$2.508	$0.962	$1.000	**$51.58**	**$92.29**
2042	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$11.27	$52.74	$43.29	**$48.49**	$2.533	$0.969	$1.000	**$51.99**	**$94.99**
2043	$5.25	7.9	6.1	$41.48	$32.03	$37.22	$11.65	$53.13	$43.68	**$48.88**	$2.558	$0.977	$1.000	**$52.41**	**$97.77**

Notes & Sources

A) http://www.glja.com/commodity-price-forecasts (01JAN2013 version)
B) Heat rates based upon the historic (~11 year) average ratio between Henry Hub spot prices and Mid-C day-ahead prices; data source: Intercontenental Exchange (www.theice.com)
C) HLH=55% of all hours (4800 of 8760 h/yr), LLH = 45% of all hours
D) http://www.bchydro.com/content/dam/hydro/medialib/internet/documents/planning_regulatory/iep_ltap/2011q1/irp_tac_mtg2_meeting0.pdf, slide 87
E) BPA 2012 Transmission, Ancillary, and Control Area Service Rate Summary
F) BPA Open Access Transmission Tariff - Schedule 9 "Real Power Loss Calculation"
G) http://www.glja.com/commodity-price-forecasts (01JAN2013 version)

Appendix I

DRAFT ORDER

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BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER

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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 Inc.
For Approval of a Multi-year Performance Based Ratemaking Plan for the Years 2014 through 2018

BEFORE:

(Date)

WHEREAS:

A. On July 5, 2013, FortisBC Inc. (FBC) 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 rates effective January 1, 2013 and January 1, 2014, pursuant to sections 59 to 61 and 89 of the Utilities Commission Act (the Act);

B. FBC seeks, among other things, approval, pursuant to sections 59 and 61 of the Act, of its existing interim rates as permanent, effective January 1, 2013;

C. FBC seeks approval, pursuant to sections 59 and 61 of the Act, of a permanent rate increase of 3.3 percent as compared to 2013 interim rates, effective January 1, 2014;

D. FBC further seeks approval of a Rate Stabilization Deferral Account for the purpose of reducing rate variance for the years 2014 through 2018;

E. FBC seeks acceptance pursuant to section 44.2 of the Act for Demand Side Management expenditures; and

F. The Commission has considered the Agreement and has determined that the Agreement is in the public interest.

G. The Commission has reviewed the Application and concludes that the requested changes as outlined in the Application should be approved.

NOW THEREFORE pursuant to Section 61(4) of the Utilities Commission Act, 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 FBC:

   a. Approval of FBC's existing rates for all customers as permanent, effective January 1, 2013.

   b. Approval of the PBR mechanisms set out in Section B of the Application for setting rates for the years 2014–2018.

   c. Approval of a Rate Stabilization Deferral Account for the purpose of mitigating rate variability during the years 2014-2018, as set out in Section B7 of the Application.

   d. Approval of permanent rates for all customers effective January 1, 2014, representing an increase of 3.3 percent as compared to 2013 rates. The increase will be applied as a general rate increase, with the exception of FBC's Residential Conservation Rate (Schedule 1), which will be applied in accordance with the pricing principle set out in Order G-3-12.

   e. Approval to flow through in rates during 2014 any increase or decrease to 2014 revenue requirements arising from a decision in the Generic Cost of Capital Stage 2 proceeding, as soon as practicable following a decision of the Commission and the effective date of such a decision.

   f. Approval to allocate Executive costs between FEI and FBC effective January 1, 2014 by way of applying the Massachusetts formula described in Section C4.17.

   g. Approval for the rate base treatment and financing of deferral accounts, as set out in Section D3.2.

   h. Approval of financing costs for 2013 at FBC's Weighted Average Cost of Capital for the six deferral accounts approved by Order G-23-13, as set out in Section D4.4.

   i. Approval of the discontinuance, modification, and creation of deferral accounts, as applicable, and the amortization and disposition of balances of deferral accounts, as set out in Section D4 and Appendix F4 of the Application and summarized in Table A2-1.

   j. Approvals of changes to the following accounting policies to be used in the determination of rates for FBC effective January 1, 2014:

      i. 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.

ii. Approval to discontinue the net-of-tax treatment for the pension and OPEB funding differences effective 2014, and instead add back the pension and OPEB expense and deduct the contributions in the calculation of income tax expense, as explained in Section D3 of the Application.

iii. Continued approval of FBC's capitalized overhead rate of 20 percent as set out in Section D3.7 of the Application.

iv. Continued approval of FBC's direct overhead charging methodology as set out in Section D3.7 of the Application.

2. With respect to Demand Side Management (DSM) expenditures, the Commission orders as follows:

a. Pursuant to section 44.2(3) of the Act, the Commission accepts the following DSM expenditure schedules as described in Appendix H of the Application: up to $3.0 million for 2014, $3.2 million for 2015, $3.2 million for 2016, $3.2 million for 2017, and $3.3 million for 2018.

b. Approval to change the amortization period of existing and future DSM expenditures from 10 years to 15 years, effective January 1, 2014.

c. Approval to discontinue semi-annual reporting on its DSM Program and to submit annual reports as of December 31 in each year, effective January 1, 2014.

DATED at the City of Vancouver, In the Province of British Columbia, this day of <MONTH>, 20XX.

BY ORDER