Appendix A

COMPANY INFORMATION

Appendix A1

LIST OF ABBREVIATIONS

1 LIST OF ABBREVIATIONS

Acronym	Definition
A&G	Administration and General
ACGS	Aitken Creek Gas Storage ULC
ADMS	Advanced Distribution Management System
AFUDC	Allowance for Funds Used During Construction
AIP	Asset Investment Planning
ALG	Average Life Group
ASL	Average Service Life
AM/FM	Asset Management and Facilities Management
AMI	Advanced Metering Infrastructure
AUC	Alberta Utilities Commission
AWE:BC	Average Weekly Earnings for British Columbia
BC or B.C.	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCMEU	British Columbia Municipal Electrical Utilities
BCOAPO	British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, *et al*
BCOGAA	British Columbia Oil and Gas Activities Act
BC OGC	British Columbia Oil & Gas Commission
BCSEA	British Columbia Sustainable Energy Association
BCUC	British Columbia Utilities Commission
BVA	Biomethane Variance Account
CAGRs	Compound Annual Growth Rates
CCA	Capital Cost Allowance
CEC	Commercial Energy Consumer's Association of British Columbia
CEPA	Canadian Energy Pipelines Association
CFS	Clean Fuel Standard
CHP	Combined Heat and Power
CIAC	Contributions in Aid of Construction
CMFL	Circumferential Magnetic Flux Leakage
CMMS	Computerized Maintenance Management System
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COS	Cost of Service
CoV	City of Vancouver
CPCN	Certificate of Public Convenience and Necessity

Acronym	Definition
CPI:BC	Consumer Price Index for British Columbia
CSA	Canadian Standards Association
DCFC	Direct Current Fast Chargers
DER	Distributed Energy Resources
DG	Distributed Generation
DP	Distribution Pressure
DSM	Demand Side Management
DRIP	Dividend Reinvestment Plan
EAM	Earnings Adjusted Mechanism
ECM	Efficiency Carry-Over Mechanism
EGD	Enbridge Gas Distribution
EHT	Employer Health Tax
ELG	Equal Life Group
EMAT	Electro-magnetic Acoustic Transducer
EMB	Eligible Mitigation Benefits
ESM	Earning Sharing Mechanism
EV	Electric Vehicles
EVP	Executive Vice President
FBC	FortisBC Inc.
FCR	First Contact Resolution
FEI	FortisBC Energy Inc.
FEVI	FortisBC Energy (Vancouver Island) Inc.
FEW	FortisBC Energy (Whistler) Inc.
FERC	Federal Energy Regulatory Commission
FHI	FortisBC Holdings Inc.
FI	Fortis Inc.
FortisBC	Collectively FEI and FBC, the Companies, or the Utilities
FTE	Full Time Equivalent
GAAP	Generally Accepted Accounting Principles
GBP	Great Britain Pounds
GC	Growth Capital
GCA	Gross Customer Additions
GGRR	Greenhouse Gas Reduction Regulation
GHG	Greenhouse Gas
GIS	Geographic Information System
GFOR	Generator Forced Outage Rate
GJ	Gigajoule
GRI	Gas Research Institute

Acronym	Definition
GST	Goods and Services Tax
GTI	Gas Technology Institute
HQD	Hydro Quebec Distribution
HQT	Hydro Quebec Transmission
HVAC	Heating, Ventilation and Air Conditioning
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IFRS	International Financial Reporting Standards
ICG	Industrial Customers Group
IGU	Inland Gas Upgrades
ILI	In-line Inspection
IMP	Integrity Management Program
IP	Intermediate Pressure
IRs	Information Requests
IRG	Irrigation Ratepayers Group
IS	Information Systems
IVR	Interactive Voice Response
kW	Kilowatt
LAN	Local Area Network
LBO	Lower Bonnington Dam
LCIF	Low Carbon Initiative Fund
LCNF	Low Carbon Network Funds
LNG	Liquefied Natural Gas
LTC	Load Tap Changer
LTERP	Long Term Electric Resource Plan
LTGRP	Long Term Gas Resource Plan
MFL	Magnetic Flux Leakage
MOCBs	Minimum Oil Circuit Breakers
MOTI	Ministry of Transportation and Infrastructure
MoveUP	Movement of United Professionals
MRP or MRPs	Multi-year Rate Plan or Plans
MRS	Mandatory Reliability Standards
MSP	Medical Services Plan
Mt	Million Tonnes
MWh	Megawatt hour
MX	Main Extension
NGIF	Canadian Gas Association’s Natural Gas Innovation Fund
NGT	Natural Gas for Transportation

Acronym	Definition
NGV	Natural Gas Vehicles
NIA	Network Innovation Allowance
NIC	Network Innovation Competition
NOx	Nitrogen Oxide
NWA	Non Wire Alternative
NYPSC	New York Public Service Commission
NYSE	New York Stock Exchange
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OEM	Original Equipment Manufacturer
OHS	Occupational Health and Safety
OM&A	Operations, Maintenance and Administrative
OMS	Outage Management System
OPEB	Other Post-Employment Benefits
OSRs	Operation Support Representatives
PBR	Performance Based Ratemaking
PCBs	Polychlorinated Biphenyls
PJ	Petajoule
PNG	Pacific Northern Gas Limited
PP&E	Property, Plant and Equipment
PPA	Power Purchase Agreement
PPE	Power Purchase Expense
PSI	Power Supply Incentive
PST	Provincial Services Tax
PV	Photovoltaics
PVC	Polyvinyl Chloride
R&D	Research and Development
RDA	Rate Design Application
RD&D	Research, Development and Demonstration
REV	New York Reforming the Energy Vision
RFP	Request for Proposal
RG	Renewable Gas
RLCFRR	Renewable and Low Carbon Fuel Requirement Regulation
RNG	Renewable Natural Gas
RPI	Retail Prices Index
ROE	Return on Equity
ROW	Right of Way
RRA	Revenue Requirements Application

Acronym	Definition
RSAM	Revenue Stabilization Adjustment Mechanism
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SIF	Strategic Innovation Fund
SLA	Service Line Addition
SLCA	Service Line Cost Allowance
SONET	Synchronous Optical Networking
SQI or SQIs	Service Quality Indicator or Indicators
T&D	Transmission and Distribution
tCO_2e	Tonnes of carbon dioxide equivalent
TESDA	Thermal Energy Services Deferral Account
TIMC	Transmission Integrity Management Capabilities
TJ	Terajoule
TOU	Time of Use
TP	Transmission Pressure
TRL	Technology Readiness Levels
TSF	Telephone Service Factor
TSX	Toronto Stock Exchange
UBO	Upper Bonnington Dam
UCA	*Utilities Commission Act*
UCC	Undepreciated Capital Cost
UCOM	Unit Cost O&M
UDC	Utility Distribution Company
UK	United Kingdom
UNDRIP	United Nations Declaration on the Rights of Indigenous Peoples
USD	United States dollar
US GAAP	US Generally Accepted Accounting Principles
USofA	Uniform System of Accounts
VFI	Vacuum Fault Interrupter
WACC	Weighted Average Cost of Capital
WACD	Weighted Average Cost of Debt
WAN	Wide Area Network
WAX CAPA	Waneta Expansion Limited Partnership
ZEV	Zero Emission Vehicle

Appendix A2

KEY OPERATING FACTS

FEI
Annual Report Statistics
2013-2018

	2013	2014	2015	2016	2017	2018
Customers:						
12 Month Average Residential Customers	856,934	868,418	876,844	890,418	902,898	920,431
12 Month Average Commercial Customers	86,323	88,156	89,281	90,639	91,691	93,204
12 Month Average Industrial Customers	366	353	256	265	278	311
12 Month Average Transportation Customers	2,243	2,256	2,372	2,475	2,504	2,399
12 Month Average NGV Customers	14	13	13	10	9	8
Total Average Customers	**945,880**	**959,196**	**968,766**	**983,807**	**997,380**	**1,016,353**
Total Year End Customers	955,761	967,452	981,689	994,004	1,008,422	1,029,476
Gas Deliveries (Normalized Actual):						
Residential Gas Delivery (TJ)	72,899	73,066	74,113	77,941	77,548	78,298
Commercial Gas Delivery (TJ)	53,305	45,691	47,171	48,380	48,838	49,977
Industrial Gas Delivery (TJ)	4,780	4,231	2,615	2,940	3,520	4,846
Transportation Gas Delivery (TJ)	67,016	73,146	88,986	94,022	98,852	96,750
NGV Gas Delivery (TJ)	50	44	51	49	30	36
Total Gas Deliveries	**198,050**	**196,178**	**212,936**	**223,332**	**228,788**	**229,907**
Cost of Gas (Normalized)						
Average Cost of Gas Sold ($/GJ)	$ 4.45	$ 5.16	$ 4.46	$ 2.92	$ 3.15	$ 2.71
O&M:						
Gross O&M Decision	$ 273,986	$ 266,536	$ 271,457	$ 272,622	$ 270,291	$ 276,668
Gross O&M Actual	266,106	258,755	261,003	260,400	260,376	269,864
O&M Transferred to Biomethane BVA	-	-404	-1,010	-1,096	-1,532	-2,560
Capitalization Allowed	-38,358	-32,735	-32,575	-32,714	-32,435	-33,200
Fort Nelson Allocation	-1,058	-838	-851	-821	-623	-1,037
Total Net O&M	**$ 226,690**	**$ 224,778**	**$ 226,568**	**$ 225,769**	**$ 225,786**	**$ 233,067**
Headcount						
Average Full Time Equivalent (FTE)	1,678	1,651	1,575	1,583	1,650	1,729
Distribution Fast Facts:						
Outages caused by Third Party	932	938	1,022	1,069	1,233	1,186
Gas Odour Calls	18,084	16,509	15,914	16,357	18,371	15,726
CO Calls	1,731	1,884	1,909	2,044	2,172	2,109
Fire Calls	842	856	896	1,000	971	1,040
Meter Recalls	82,857	81,815	87,485	92,104	77,921	59,949
Locates	4,067	5,245	4,735	4,295	4,185	4,507
Calls to BC 1 Call	92,002	107,509	122,627	129,645	146,868	157,708
Lock Offs (Includes Contractor)	14,337	18,389	10,789	12,773	10,801	13,344
Lock Offs (Excludes Contractor)	9,177	9,949	5,877	6,284	5,568	7,233
Unlocks	12,548	13,986	9,740	10,733	9,522	10,965
Service Lines (Risers)	872,257	879,183	881,096	889,375	899,558	911,755
Total Valves	30,360	30,193	30,718	31,099	31,231	34,879
Regulator Stations	483	488	486	496	500	503
Line Heaters	225	232	238	242	246	246
Pipeline Stats:						
Total TP Pipe (KM's)	2,958	2,958	2,958	2,959	2,959	2,959
Total IP (KM's)	714	712	716	704	703	705
Total DP Service Pipe (KM's)	21,118	21,227	21,700	22,045	22,278	22,540
Total DP Main Pipe (KM's)	22,575	22,602	22,813	22,951	23,060	23,268
Total Pipeline	**47,365**	**47,499**	**48,187**	**48,659**	**49,000**	**49,472**
System Outages:						
Outages	968	972	1,058	1,104	1,269	1,219
Customers Affected	1,478	3,730	1,835	2,234	2,040	1,314
System Leaks:						
Distribution Pipeline Leaks	**602**	**672**	**599**	**696**	**1,126**	**990**
BGC1	414	395	408	480	668	699
BGC2	155	140	161	181	174	191
BGC3	33	137	30	35	284	100
Emergency Response Time (minutes)	N/A	21.09	20.55	20.37	20.37	20.13
Miscellaneous:						
Rate Base, Mid-Year	$ 3,573,353	$ 3,587,772	$ 3,646,848	$ 3,676,416	$ 3,726,808	N/A
Allowed Return	8.75%	8.75%	8.75%	8.75%	8.75%	8.75%

FBC
Annual Report Statistics
2013-2018

	2013	2014	2015	2016	2017	2018
O&M:						
Gross O&M Decision ($000s)	$57,621	$60,710	$59,091	$56,979	$57,549	$58,591
Gross O&M Actual ($000s)	$56,696	$59,723	$57,785	$55,609	$55,821	$57,355
Capitalization Allowed ($000s)	$(11,524)	$(9,106)	$(8,864)	$(8,547)	$(8,632)	$(8,787)
Total Net O&M ($000s)	**$ 45,172**	**$ 50,616**	**$ 48,921**	**$ 47,063**	**$ 47,189**	**$ 48,568**
Headcount						
Full Time Equivalent (FTE)	309	503	507	487	512	525
Transmission & Distribution Stats:						
Distribution Lines (km)	5,830	5,860	5,900	5,935	5,960	5,988
Transmission Lines (km)	1,336	1,340	1,290	1,297	1,295	1,290
Total Transmission and Distribution Lines (km)	7,166	7,200	7,190	7,232	7,255	7,278
Total Substations	65	65	65	65	65	65
System Losses (%) - Gross Load	7.9	7.9	7.9	7.9	8.0	8.0
Peak Demand (MW) - Summer	579	601	597	594	593	630
Peak Demand (MW) - Winter	699	684	624	712	731	663
Power Supply Stats:						
Generation (GWh)	1,567	1,571	1,628	1,619	1,575	1,575
Generating Capacity (MW)	223	225	225	225	225	225
Total Power Purchases (GWh)	1,922	1,880	1,788	1,772	1,979	1,928
Total DSM Energy Saved (GWh)	29.5	14.6	12.6	22.8	27.8	26.7
Miscellaneous:						
Rate Base, Mid-Year ($000s)	$ 1,142	$ 1,205	$ 1,251	$ 1,282	$ 1,291	N/A
Allowed Return	9.15%	8.15%	9.15%	9.15%	9.15%	9.15%

Appendix A3

HISTORY OF O&M

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW
2013-2017 ACTUAL
($000)

Line No.	Particulars	Reference	2013	2014	2015	2016	2017
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Supervision	110-11	$ 11,898	$ 13,517	$ 13,764	$ 14,098	$ 15,020
2	Distribution Supervision Total	110-10	11,898	13,517	13,764	14,098	15,020
3							
4	Support - Distribution	110-21	10,145	11,030	11,343	9,654	8,295
5	Preventative Maintenance - Distribution	110-22	2,593	2,915	2,551	3,061	3,022
6	Operations - Distribution	110-23	7,613	7,318	6,801	7,411	7,559
7	Emergency Management - Distribution	110-24	6,595	6,490	6,111	5,902	6,028
8	Field Training - Distribution	110-25	3,546	3,427	2,705	3,600	2,967
9	Meter Exchange - Distribution	110-26	2,708	2,780	2,903	3,317	3,101
10	Distribution Operations Total	110-20	33,200	33,960	32,413	32,945	30,973
11							
12	Corrective - Distribution	110-31	6,842	5,536	5,663	5,401	5,977
13	Distribution Maintenance Total	110-30	6,842	5,536	5,663	5,401	5,977
14							
15	Account Services - Distribution	110-41	1,292	1,693	1,371	1,559	1,496
16	Bad Debt Management - Distribution	110-42	778	1,090	755	899	700
17	Distribution Meter to Cash	110-40	2,070	2,784	2,125	2,458	2,195
18							
19	**Distribution Total**	**110**	**54,010**	**55,797**	**53,964**	**54,903**	**54,166**
20							
21	Transmission Supervision	120-11	934	1,060	1,169	1,147	1,210
22	Transmission Supervision Total	120-10	934	1,060	1,169	1,147	1,210
23							
24	Pipeline / Right of Way Operations	120-21	10,486	11,865	12,403	13,890	13,820
25	Compression Operations	120-22	3,773	4,263	5,836	6,071	6,057
26	Measurement Control Operations	120-23	656	325	1,117	1,187	1,422
27	Transmission Operations Total	120-20	14,915	16,453	19,356	21,148	21,299
28							
29	Pipeline / Right of Way - Maintenance	120-31	837	460	1,275	230	315
30	Compression - Maintenance	120-32	563	717	1,360	1,043	698
31	Measurement Control Operations	120-33	280	356	148	192	182
32	Transmission Maintenance Total	120-30	1,681	1,533	2,783	1,465	1,195
33							
34	**Transmission Total**	**120**	**17,530**	**19,046**	**23,308**	**23,760**	**23,703**
35							
36	LNG Plant Operations	130-11	4,331	4,698	4,967	6,110	7,716
37	LNG Plant Operations Total	130-10	4,331	4,698	4,967	6,110	7,716
38							
39	LNG Plant Maintenance	130-21	297	683	1,223	910	309
40	LNG Plant Maintenance Total	130-20	297	683	1,223	910	309
41							
42	**LNG Plant Total**	**130**	**4,629**	**5,380**	**6,190**	**7,019**	**8,025**
43							
44	**Operations Total**	**100**	**76,169**	**80,224**	**83,463**	**85,682**	**85,894**
45							
46	Customer Service Supervision	200-11	491	814	287	291	298
47	Customer Assistance	200-12	12,089	12,302	10,493	10,159	10,181
48	Customer Billing	200-13	25,267	12,755	11,668	11,267	11,389
49	Meter Reading	200-14	12,453	11,383	11,274	11,631	11,709
50	Credit & Collections	200-15	3,004	4,997	2,452	1,815	2,467
51	Customer Operations	200-16	2,135	3,242	3,947	3,319	3,671
52	Customer Service Total	200-10	55,439	45,493	40,121	38,481	39,715
53							
54	**Customer Service Total**	**200**	**55,439**	**45,493**	**40,121**	**38,481**	**39,715**

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
2013-2017 ACTUAL
($000)

Line No.	Particulars	Reference	2013	2014	2015	2016	2017
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Energy Solutions & External Relations Supervision	300-11	$ 1,014	$ 973	$ 971	$ 762	$ 923
2	Energy Solutions	300-12	6,443	6,480	7,695	8,204	8,179
3	Energy Efficiency	300-13	816	889	1,399	1,479	1,297
4	Corporate Communications & External Relations	300-14	7,146	7,411	8,852	8,155	9,218
5	Forecasting, Market & Business Development	300-15	5,957	6,181	6,056	6,589	6,463
6	Energy Solutions & External Relations Total	300-10	21,376	21,935	24,974	25,190	26,081
7							
8	**Energy Solutions & External Relations Total**	**300**	**21,376**	**21,935**	**24,974**	**25,190**	**26,081**
9							
10	Energy Supply & Resource Development	410-11	2,469	2,511	2,400	2,355	2,521
11	Gas Control	410-12	1,562	1,686	2,113	2,235	2,103
12	Energy Supply & Resource Development Total	410-10	4,031	4,196	4,513	4,590	4,624
13							
14	**Energy Supply & Resource Development Total**	**410**	**4,031**	**4,196**	**4,513**	**4,590**	**4,624**
15							
16	Information Systems Supervision	420-11	4,185	4,362	4,830	4,198	4,391
17	Application Management	420-12	13,728	13,850	14,594	15,590	12,717
18	Infrastructure Management	420-13	7,418	8,083	8,805	6,741	7,413
19	Information Systems Total	420-10	25,331	26,296	28,229	26,529	24,521
20							
21	**Information Systems Total**	**420**	**25,331**	**26,296**	**28,229**	**26,529**	**24,521**
22							
23	System Planning	430-11	7,607	6,837	7,086	7,035	7,039
24	Engineering	430-12	7,193	7,613	8,443	8,733	7,683
25	Project Management	430-13	1,014	933	850	614	774
26	Engineering Services & Project Management Total	430-10	15,814	15,383	16,379	16,382	15,496
27							
28	**Engineering Services & Project Management Total**	**430**	**15,814**	**15,383**	**16,379**	**16,382**	**15,496**
29							
30	Supply Chain	440-11	4,424	4,822	4,493	4,470	4,393
31	Measurement	440-12	6,129	7,012	7,589	7,028	6,534
32	Property Services	440-13	1,364	1,625	1,364	1,699	1,576
33	Operations Support Total	440-10	11,917	13,459	13,446	13,197	12,503
34							
35	**Operations Support Total**	**440**	**11,917**	**13,459**	**13,446**	**13,197**	**12,503**
36							
37	Facilities Management	450-11	9,739	9,719	9,537	9,836	10,383
38	Facilities Total	450-10	9,739	9,719	9,537	9,836	10,383
39							
40	**Facilities Total**	**450**	**9,739**	**9,719**	**9,537**	**9,836**	**10,383**
41							
42	Environment Health & Safety	460-11	2,680	2,910	3,159	3,669	4,217
43	Environment Health & Safety Total	460-10	2,680	2,910	3,159	3,669	4,217
44							
45	**Environment Health & Safety Total**	**460**	**2,680**	**2,910**	**3,159**	**3,669**	**4,217**
46							
47							
48	**Business Services Total**	**400**	**69,511**	**71,964**	**75,264**	**74,203**	**71,744**

FORTISBC ENERGY INC
OPERATION & MAINTENANCE EXPENSES - ACTIVITY VIEW (CONT'D)
2013-2017 ACTUAL
($000)

Line No.	Particulars	Reference	2013	2014	2015	2016	2017
	(1)	(2)	(3)	(4)	(5)	(4)	(3)
1	Financial & Regulatory Services	510-11	$ 13,363	$ 14,080	$ 13,599	$ 13,534	$ 13,391
2	Financial & Regulatory Services Total	510-10	13,363	14,080	13,599	13,534	13,391
3							
4	**Financial & Regulatory Services Total**	**510**	**13,363**	**14,080**	**13,599**	**13,534**	**13,391**
5							
6	Human Resources	520-11	8,305	9,285	9,109	9,015	9,049
7	Human Resources Total	520-10	8,305	9,285	9,109	9,015	9,049
8							
9	**Human Resources Total**	**520**	**8,305**	**9,285**	**9,109**	**9,015**	**9,049**
10							
11	Legal	530-11	2,299	2,174	1,814	2,056	1,809
12	Internal Audit	530-12	755	792	790	799	767
13	Risk Management/Insurance	530-13	5,990	6,491	6,599	5,888	5,603
14	Governance	530-10	9,044	9,457	9,204	8,743	8,179
15							
16	**Governance Total**	**530**	**9,044**	**9,457**	**9,204**	**8,743**	**8,179**
17							
18	Administration & General	540-11	481	187	(180)	(548)	483
19	Shared Services Agreement	540-12	4,525	5,164	4,481	5,159	5,096
20	Retiree Benefits	540-16	6,709	0	(0)	-	-
21	Corporate Total	540-10	11,715	5,351	4,301	4,611	5,579
22							
23	**Corporate Total**	**540**	**11,715**	**5,351**	**4,301**	**4,611**	**5,579**
24							
25	**Corporate Services Total**	**500**	**42,427**	**38,173**	**36,213**	**35,902**	**36,197**
26							
27	**Total Gross O&M Expenses**		**264,923**	**257,788**	**260,034**	**259,459**	**259,631**
28							
29	Less: Biomethane Transferred to BVA		-	(404)	(1,010)	(1,096)	(1,532)
30	Less: Capitalized Overhead		(38,233)	(32,605)	(32,457)	(32,594)	(32,313)
31							
32	**Total O&M Expenses**		**$ 226,690**	**$ 224,778**	**$ 226,568**	**$ 225,769**	**$ 225,786**

FORTISBC INC.

OPERATING AND MAINTENANCE EXPENSE
2013 - 2017 ACTUAL
($000s)

Line No.	Account	Particulars	2013	2014	2015	2016	2017
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1		GENERATION					
2	535R	Supervision & Administration	$ 815	$ 682	$ 778	$ 408	$ 446
3	536	Water Fees	9,397	9,600	9,714	10,182	10,316
4	542	Structures	861	659	724	643	779
5	543	Dams & Watersays	264	271	279	172	278
6	544	Electric Plant	455	989	965	1,575	1,333
7	545	Other Plant	159	358	373	307	223
8			$ 11,951	$ 12,559	$ 12,832	$ 13,288	$ 13,374
9							
10		OTHER POWER SUPPLY					
11	555	Purchased Power	$ 83,052	$ 86,337	$ 110,707	$ 123,169	$ 133,214
12	556	System Control	2,076	2,207	2,140	2,298	2,211
13			$ 85,128	$ 88,544	$ 112,847	$ 125,467	$ 135,425
14							
15		TRANSMISSION & DISTRIBUTION					
16	560R-1	Supervision & Administration	$ 1,704	$ 2,028	$ 2,257	$ 2,228	$ 2,039
17	560R-2	System Planning	2,277	2,764	2,862	3,074	3,256
18	561	Load Dispatching	1,300	1,301	1,228	1,357	1,379
19	562	Transmission Station Expense	1,016	922	921	847	870
20	563R-1	Transmission Line Maintenance	632	468	625	539	586
21	563R-2	Transmission Right of Way Maintenance	1,706	1,699	1,333	1,507	1,085
22	565	Wheeling	5,225	5,132	4,800	4,815	5,124
23	567	Rents	3,238	3,410	3,372	3,345	3,126
24	583R-1	Distribution Line Maintenance	4,597	4,227	3,990	3,401	3,908
25	583R-2	Distribution Right of Way Maintenance	3,785	4,121	4,124	3,817	4,374
26	586	Meter Expenses	694	782	564	708	567
27	592	Distribution Station Expense	1,607	1,682	1,197	1,790	1,700
28	596	Street Lighting	48	90	66	68	51
29	598	Other Plant	237	306	319	249	266
30			$ 28,066	$ 28,932	$ 27,657	$ 27,745	$ 28,331
31		CUSTOMER SERVICE					
32	901	Supervision & Administration	$ 1,840	$ 1,680	$ 1,489	$ 1,722	$ 1,853
33	902	Meter Reading	1,763	2,228	1,683	231	212
34	903	Customer Billing	720	628	572	594	569
35	904	Credit & Collections	1,243	1,313	1,347	989	1,151
36	910	Customer Assistance	2,616	3,031	2,473	2,688	2,716
37			$ 8,183	$ 8,880	$ 7,565	$ 6,223	$ 6,501

FORTISBC INC.

OPERATING AND MAINTENANCE EXPENSE
2013 - 2017 ACTUAL
($000s)

Line No.	Account	Particulars	2013	2014	2015	2016	2017
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1		ADMINISTRATIVE AND GENERAL					
2	920	Salaries					
3	920.1	Executive and Senior Management	$ 848	$ 727	$ 885	$ 524	$ 551
4	920.2	Legal	740	803	544	692	474
5	920.3	Human Resources	688	959	750	599	482
6	920.4	Regulatory and Finance	917	1,429	1,254	1,223	941
7	920.6	Information Services	832	1,486	1,591	1,216	1,377
8	920.7	Materials Management	91	188	7	(10)	(95)
9		Other	345	400	243	308	140
10			$ 4,460	$ 5,992	$ 5,273	$ 4,551	$ 3,870
11							
12		ADMINISTRATIVE AND GENERAL cont'd					
13	921	Expenses					
14	921.1	Executive and Senior Management	$ 111	$ 28	$ 52	$ 45	$ 34
15	921.2	Legal	259	312	345	228	244
16	921.3	Human Resources	137	109	163	98	83
17	921.4	Regulatory and Finance	114	60	273	142	270
18	921.6	Information Services	613	1,199	1,398	1,527	1,441
19	921.7	Materials Management	61	256	293	343	370
20		Other	267	242	353	181	296
21			$ 1,562	$ 2,206	$ 2,877	$ 2,564	$ 2,740
22							
23	567	Special Services	$ 838	$ 1,914	$ 2,449	$ 2,887	$ 3,090
24	283R-1	Insurance	517	836	882	854	880
25	283R-2	Maintenance to General Plant	1,450	1,294	1,253	1,392	1,388
26	586	Transportation Equipment Expenses	689	528	508	258	243
27			$ 3,494	$ 4,572	$ 5,092	$ 5,391	$ 5,601
28							
29		**TOTAL**	**142,845**	**151,686**	**174,142**	**185,229**	**195,843**
30							
31	Less:	Water Fees	(5,225)	(5,132)	(4,800)	(10,182)	(10,316)
32		Power Purchases	(83,052)	(86,337)	(110,707)	(123,169)	(133,214)
33		Wheeling	(9,397)	(9,600)	(9,714)	(4,815)	(5,124)
34		***Net O&M Expense***	***45,172***	***50,616***	***48,921***	***47,063***	***47,189***
35							
36	Add:	Capitalized Overhead	11,524	9,106	8,864	8,547	8,632
37							
38		***GROSS O&M Expense***	***56,696***	***59,723***	***57,785***	***55,609***	***55,821***

Appendix A4

MUNICIPALITIES SERVED

MUNICIPALITIES SERVED – FEI (MAINLAND AND VANCOUVER ISLAND):

100 Mile House
108 Mile Ranch
150 Mile House
70 Mile House
Abbotsford
Agassiz
Aldergrove
Anmore
Armstrong
Arrow Creek
Ashcroft
Bear Lake
Belcarra
Blind Bay
Brackendale
Britannia Beach (Furry Creek
Burnaby
Cache Creek
Campbell River
Castlegar
Cawston
Chase
Chemainus
Cherry Creek
Chetwynd
Chilliwack
Christina Lake
Clinton
Coldstream
Comox
Copper Creek
Coquitlam
Corbin
Courtney
Cranbrook
Creston
Cultus Lake
Delta
Deep Creek
Duncan
Elkford
Elko
Enderby
Falkland
Fernie
Forest Grove
Fort Nelson
Fruitvale
Galloway
Grand Forks
Greenwood
Grindrod
Hasler Flats
Harrison Hot Springs
Hedley
Heffley Creek
Hixon
Hope
Hudson's Hope
Jaffray
Kaleden
Kamloops
Kelowna
Kent
Keremeos
Kersley
Kimberley
Kitchener
Lac La Hache
Ladysmith
Lake Country
Langford
Langley
Lantzville
Lindell Beach
Logan Lake
Lone Butte
Lower Nicola
Lumby
Mackenzie
Maple Ridge
Merritt
Midway
Mission
Monte Lake
Montrose
Nanaimo
Nanoose Bay
Naramata
Nelson
New Westminster
North Cowichan
North Saanich
North Vancouver District
Okanagan Falls
Oliver
Osoyoos
Oyama
Parksville
Peachland
Penticton
Pitt Meadows
Port Alberni
Port Coquitlam
Port Moody
Powell River
Prince George
Princeton
Pritchard
Prophet River
Qualicum Beach
Quesnel
Revelstoke
Richmond

Robson
Rock Creek
Rosedale
Rossland
Salmo
Salmon Arm
Savona
Sechelt
Skookumchuck
Sorrento
South Slocan
Spallumcheen
Sparwood
Squamish
Summerland
Surrey
Tappen
Tobiano
Trail
Tsawwassen
Vancouver
Vernon
Virtual
Warfield
West Kelowna
West Vancouver
Westwold
White Lake
White Rock
Williams Lake
Willow Flats
Winfield
Wynndel
Yahk

FBC 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 A5

FORTISBC CLEAN GROWTH PATHWAY

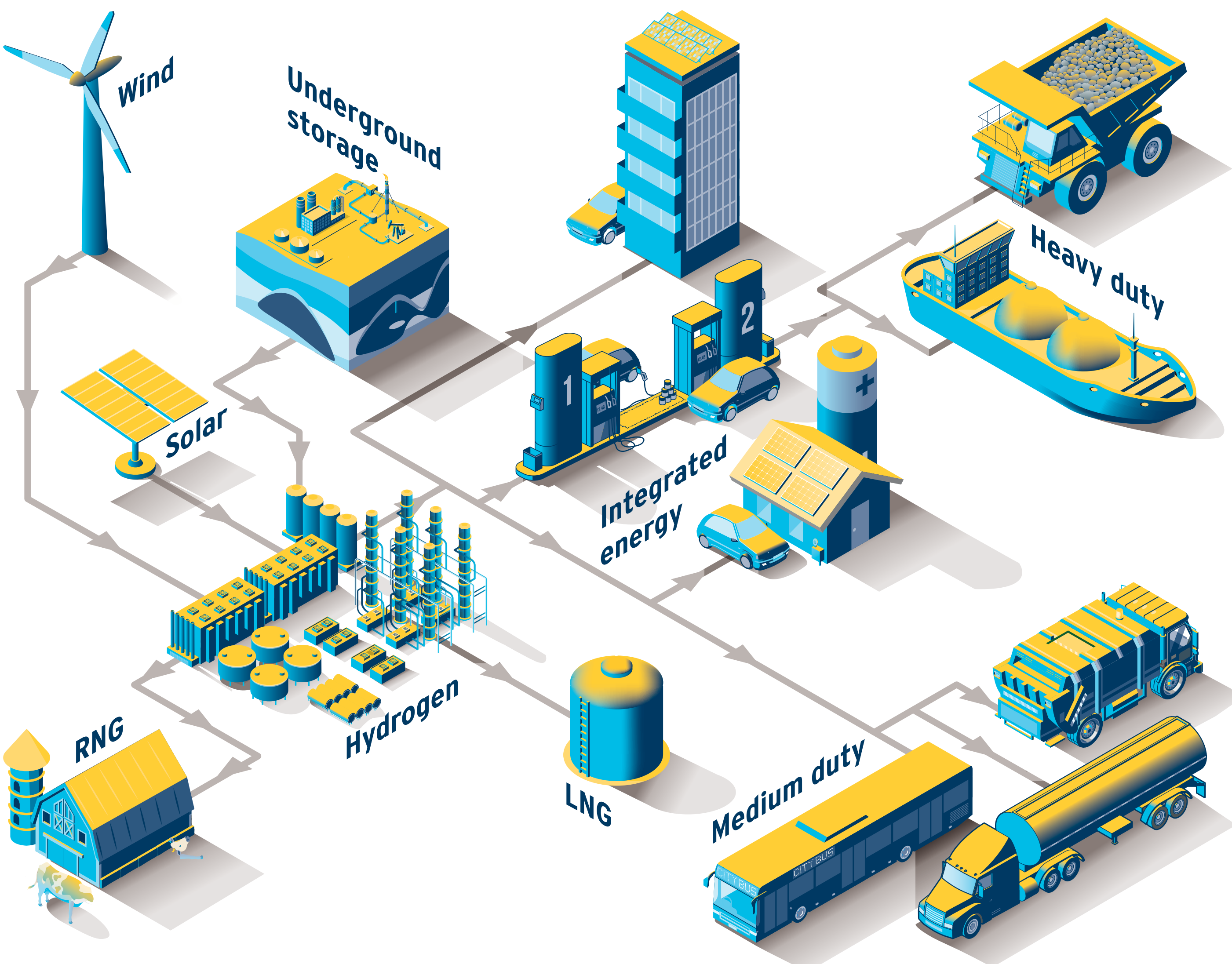
Clean growth pathway to 2050

Contents

Affordability, clean energy and efficiency: FortisBC's clean growth pathway

We believe FortisBC has an important role to play in helping British Columbia move to a low-carbon, renewable energy future. We see ourselves as an energy delivery company that has climate and economic solutions in the buildings and transportation sectors. Millions of British Columbians we serve in communities across the province look to us to deliver energy safely, reliably and affordably every day. As a subsidiary of our Canadian-based parent company, Fortis Inc., one of the largest energy companies in North America, we're committed to helping British Columbia achieve its climate goals and addressing climate change solutions in a global context. We're focused on providing practical solutions that can be implemented today by leveraging our existing infrastructure.

Figure 1: FortisBC's role in driving BC's sustainable prosperity



This paper presents FortisBC's pathway to align with the provincial government's goal to significantly reduce greenhouse gas emissions while supporting economic growth and maintaining affordability and customer choice. Our approach combines several strategies that together outline a clear pathway to significant emissions reductions and signal a paradigm shift in the way we relate to energy.

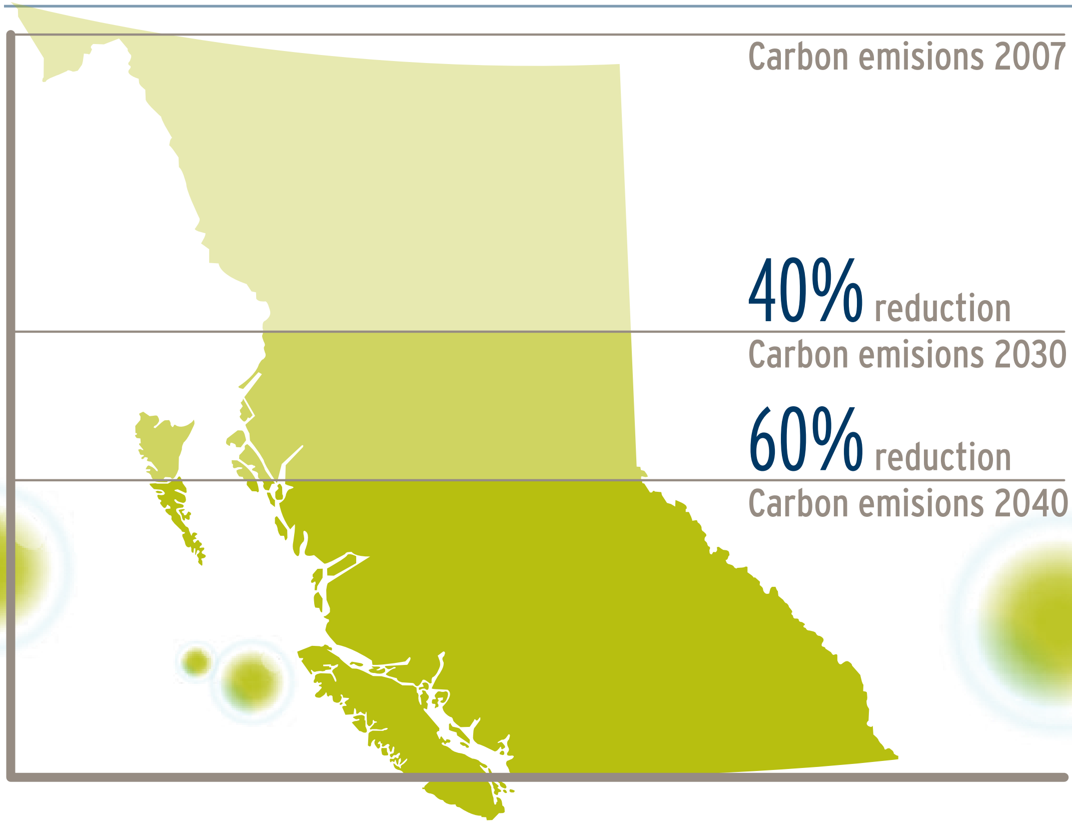
Our pathway calls for four significant shifts in our energy systems to foster market transformation:

- making significant investments in both low and zero carbon vehicles and infrastructure in the transportation sector
- transitioning from higher carbon energy sources to lower carbon sources by ramping up Renewable Natural Gas (RNG) and hydrogen deployment to achieve a ten per cent zero-carbon fuel supply by 2030 and a thirty per cent supply by 2050
- positioning BC as a vital domestic and international Liquefied Natural Gas (LNG) provider to lower global GHG emissions
- tripling our investment in energy efficiency in the built environment and developing innovative energy projects in BC's communities

Introduction

British Columbia (BC) has committed to achieving deep carbon reductions in greenhouse gas (GHG) emissions by 2050. The province recently updated its climate targets to a 40 per cent reduction in carbon emissions from 2007 levels by 2030, and a 60 per cent reduction from 2007 levels by 2040. Achieving these long-term targets will require immediate and coordinated action by policy makers, regulators and industry. The province will need more than aspirations to achieve real, timely results.

Provincial Carbon Emission Goals



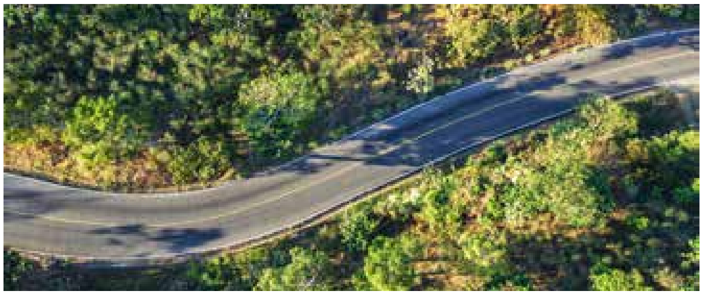
We believe we have a significant role to play in helping the BC Government deliver on its climate and energy goals. Our pathway is based upon our commitment to investing in projects that will make life more affordable for British Columbians, improve efficiency, reduce GHG emissions and drive innovation. By strategically managing BC's existing energy infrastructure and investing in new low-carbon energy supply, we see a long-term opportunity to continue creating sustainable, good-paying jobs across BC.

In 2015, BC's emissions were 63 million tonnes (Mt) of CO_2e. Most emissions fall into three categories: transportation, buildings and industry. We recommend any sectoral targets being considered should be proportionate to the sector's share of GHG emissions and the ability to deliver cost-effective emissions reductions using our current infrastructure.

For example, the commercial transportation sector is the largest contributor to BC's emissions at 25 per cent. The provincial government can achieve large emission reductions in transport using today's commercially-available technology. Practical and affordable solutions that can be implemented immediately should be differentiated from aspirational goals that require technology breakthroughs.

25%
of BC's CO_2 emissions are from commercial transportation

A made-in-BC pathway



As a utility serving gas, electric and alternative energy customers, FortisBC recommends developing an integrated, system-wide evaluation of achieving the province's carbon reduction objectives. Because FortisBC delivers the most energy to consumers of any entity in the province, we have a keen interest in British Columbians understanding the system-wide impacts of various pathways that meet the province's GHG emissions targets. BC's electric and gas energy systems work in tandem to provide reliable energy to British Columbians. Both systems complement one another, providing redundancy and a low-cost solution to delivering energy to British Columbians. FortisBC believes that the provincial pathway should be guided by strong analysis and pursue a strategy that utilizes 'every tool in the toolbox': all of our provincial energy resources and existing infrastructure will be needed to achieve long-term GHG emissions reductions.

Many low-carbon pathways have emphasized the importance of the electrification of end-uses. We agree that electricity will play a key role in reducing emissions but we also caution that there are significant challenges to this strategy. Notably, the direct substitution of electricity for gas to meet heating load, coupled with growth in other areas like electric vehicles, would far exceed the available electric infrastructure and add significant costs to the existing system which would be borne by all BC residents.

FortisBC supports the provincial government's commitment to undertake a review of BC Hydro and incorporate the findings into the Clean Growth Strategy. As we consider how best to transition to a sustainable and innovative economy, we believe there is a need to reflect the real cost of all energy in our long-term goals and strategies.

FortisBC believes that gas—as an energy carrier—will continue to be a critical component of a decarbonized energy system in British Columbia. Gas infrastructure in the province is a multi-billion dollar asset that provides reliable, safe, affordable and high-quality energy services to British Columbians. This infrastructure is designed to serve difficult-to-decarbonize end-uses such as building and industrial heating and heavy-duty freight. Additionally, BC's gas infrastructure is equipped to handle decarbonization pathways that use drop-in fuels such as RNG and hydrogen, along with other key mitigation options like carbon capture and storage. The provincial government and stakeholders like FortisBC need to work to define the key role of the gas system to achieve our GHG reduction objectives and develop policies and other support mechanisms to leverage this system in a low-carbon transition.

Transportation

The transportation sector accounts for 39 per cent of BC's total emissions, making it the most important sector where we can achieve significant and immediate carbon reductions with technology that is available to us today. FortisBC is a leader in North America, providing innovative and clean technology that lowers emissions throughout the transportation sector.

BC's transportation sector accounts for

39%

of our CO_2 emissions

The decarbonization of BC's transportation sector will require the use of all tools available to us including:

- cleaner transportation systems, including increased investment in fueling infrastructure, clean trade corridors
- cleaner fuels that displace high carbon fuels with alternative fuels such as natural gas, RNG, biofuels or hydrogen
- cleaner vehicles that use alternative fuels, electric power or hybrid technologies

Cleaner transportation systems

BC Ferries new Salish Orca is fueled by natural gas—an innovative and clean solution that will provide benefits to BC Ferries' customers and the provincial economy.

Marine

The marine sector represents a massive GHG reduction and economic opportunity that should be the top priority in the province's Clean Growth Strategy. BC has had excellent early success in advancing liquefied natural gas (LNG) in the domestic marine sector that serves as a foundation to build upon for other markets.

BC Ferries launched their fourth LNG vessel this summer with a fifth expected next year and Seaspan Ferries now operates two LNG vessels in BC waters. With five LNG vessels in operation, BC Ferries, for example, expects to reduce their fuel costs by millions of dollars and CO_2 emissions by 21,500 tonnes annually, the equivalent of taking approximately 4,400 vehicles off the road per year. To put that in perspective, that's more than double the 2,200 battery electric vehicles that were purchased in all of BC in 2017.

The *Spirit of British Columbia* is the first vessel in the world to refuel LNG through delivery on a fully enclosed vehicle deck. In collaboration with BC Ferries, FortisBC developed a proprietary tanker truck technology to deliver fuel while on board the vessel. Innovative solutions like this help make it easier for transportation customers to make the switch to LNG.

The conversion of BC Ferries' two largest ships in the fleet, along with the introduction of three new natural gas-fueled Salish Class vessels last year, improves sustainability and affordability for ferry users. FortisBC is proud to have partnered with BC Ferries to develop these innovative and clean solutions that will provide benefits to BC Ferries' customers and the provincial economy.

Clean Trade Corridors

FortisBC applauds the provincial government for initiating the Clean Transportation in BC Trade Corridors initiative. We see this multi-stakeholder collaboration as an essential forum to ensure that BC and Canada are in position to capitalize on international conventions that will reduce the use of dirtier fuels and drive the adoption of LNG in the marine sector. The group's mandate to improve competitiveness and reduce GHGs is well focused and timely—conventions set by the International Maritime Organization (IMO) will take effect by 2020 which is an incredibly short period to transition the practices of international vessels in BC's ports.

Marine vessels that regularly call at BC ports originate from ports of other countries are not included in the provincial emissions inventory, yet these vessels emit a significant amount of emissions when in transit and when berthed in our ports. GHG emissions from this segment of international marine transport are approximately 70 million Mt of CO_2e per year—greater than BC's total annual GHG emissions. These emissions should be considered as part of the province's global GHG reduction strategy by displacing high-carbon marine fuels with low-carbon LNG.

Greenhouse gas emissions from international marine shipping currently represent around 2.6 per cent of total global emissions, but this share could more than triple by 2050 if measures are not taken to help speed a transition to a low-carbon environment in this sector. Following the Paris Climate Agreement, discussions began at the IMO to agree to an Initial Greenhouse Gas Strategy to stipulate significant measures to mitigate emissions. In April 2018, The IMO agreed on its first strategy to reduce GHG emissions in the international shipping sector to meet the Paris Agreement goals. The IMO strategy includes a target to reduce carbon emission by at least 50 per cent compared with 2008 levels by 2050. This strategy presents a challenge for a sector that has traditionally faced significant barriers to innovations and an opportunity for BC to position itself as a low-carbon fuel provider in the form of LNG.

Low-carbon fuels such as LNG will be critical to achieving the IMO emission reduction targets. BC is well-positioned to assist in these efforts and become a world leader in LNG bunkering. The provincial government should consider developing policies to start addressing these emissions such as including the ability to generate compliance credits with the Renewable and Low Carbon Fuel Requirement Regulation if international marine vessels use lower carbon fuels such as LNG.

FortisBC was the first company in the world to offer onboard truck-to-ship LNG bunkering. This proprietary design was developed by collaborating with Seaspan Ferries, BC Ferries and the their shipbuilders to create a customized solution to fit our customers' needs.

FortisBC has the infrastructure in place to be ready for 2020. FortisBC has completed construction of a $400-million LNG expansion project at our Tilbury facility which includes a new storage tank and additional liquefaction capacity. Plans are being developed to increase the Tilbury LNG facility's liquefaction capacity up to to three million tonnes per annum, expand LNG storage by another 92,000 cubic metres and provide ship loading facilities to serve these markets. Our Tilbury LNG facility is powered by electricity, creating safe, clean, low-greenhouse gas emitting LNG.

Expanding our natural gas liquefacation capacity by

92,000

cubic meters

Locally, other agencies such as the Port of Tacoma are also working to position themselves for success. Puget Sound Energy (PSE) is developing an LNG production facility that will enable LNG supply for marine and transportation markets in the region. This LNG facility will incorporate LNG liquefaction, storage and bunkering to the marine market. The project is scheduled to be completed in late 2019 and would compete with BC. FortisBC believes there is a limited window of time for BC to establish itself as an LNG bunkering hub before 2020. BC has an advantage as we have an ample supply of clean LNG available at globally competitive rates.

FortisBC recommends the following actions:

- Continue supporting the Clean Transportation in BC Trade Corridors initiative. Specifically, the opportunity to introduce a pilot program to convert drayage vehicles from diesel to compressed natural gas (CNG) and the advancement of the LNG bunkering in advance of 2020. The provincial and federal governments need to advance the regulation, financial tools for bunkering infrastructure and policies to establish BC as a global leader in LNG bunkering.
- Amend British Columbia's Renewable Low Carbon Fuel Reduction Regulation to generate credits for LNG bunkering that lower international shipping emissions.
- Work with the federal government to develop policies that account for the role of BC LNG in meeting global GHG reduction targets via Article Six of the Paris Agreement.

Cleaner fuels

FortisBC supports the provincial government's proposal to support the transition to cleaner fuels. We see RNG as being an essential component of this transition.

FortisBC was the first utility in North America to offer RNG to residential customers in 2011. RNG is a critical source of renewable energy that is helping the province achieve its GHG emission reduction target. Farms, landfills and other suppliers like the City of Surrey have teamed up with FortisBC to capture methane (CH4) from organic waste, which would otherwise escape into the atmosphere. This methane, also known as biogas, is purified to make RNG.

FortisBC's RNG program is enabled by a British Columbia Ministerial Regulation, the Greenhouse Gas Reduction Regulation (GGRR). The GGRR has facilitated the development of five operational projects which are forecasted to supply over 203,000 GJ of RNG this year. These facilities capture biogas, clean and upgrade the biogas into RNG, and inject the RNG into our distribution system. Since the RNG offering launched to residential customers in June 2011 and commercial customers in March 2012, over 9,000 customers have subscribed to this offering and have helped reduce GHG emissions an equivalent amount to removing 7,200 cars from the road.

Though FortisBC has achieved important early successes in the residential and commercial sectors, further work is required to grow BC's supply of RNG for use in the transportation sector. Innovations in biogas could boost our supply of RNG to between 25 and 46 per cent of FortisBC's annual natural gas demand by 2036. Power-to-gas, the process of converting electric power into carbon-neutral hydrogen, presents a further opportunity and could account for between five and 15 per cent of annual demand by 2036.

We believe that hydrogen will be a key driver towards reducing BC's carbon emissions, not only as an alternative fuel to enable the decarbonisation of heating, but as a means of storing renewable power (hydroelectric, solar and wind) and, through this, linking together the decarbonisation of the building, industry and transport sectors. We believe in taking a system-wide perspective of hydrogen as a technology that further integrates the electric and gas systems by acting as a high capacity storage medium for carbon-free power generation and a carbon-free fuel for heat and transport.

Turning waste into fuel

Earlier this year, we joined the City of Surrey and the Government of Canada to open North America's first closed loop waste management system. The facility will convert curbside organic waste into renewable biofuel to fuel the City's fleet of natural gas powered waste collection and service vehicles. Under this closed loop system, waste collection trucks will literally be collecting their fuel source at curbside. Excess fuel will go to the new district energy system that heats and cools Surrey's City Centre.

The potential of a low-carbon gas system

In its 2017 Long-Term Gas Resource Plan, FortisBC outlined a preliminary analysis of initiatives that could achieve significant GHG emissions reductions by 2030. Emissions reductions opportunities for FortisBC fall into three categories: i) decarbonizing pipeline gas with RNG, hydrogen and carbon capture and storage; ii) energy efficiency and demand-side management (DSM); and iii) fuel switching from more carbon-intensive energy to pipeline gas and LNG.

Should low-carbon gases like RNG and hydrogen achieve a notable share of the total supply in the gas distribution system, FortisBC estimates that the technical potential to reduce GHG emissions would be up to 2.7 and 5.0 Mt. This would reduce emissions from natural gas consumption by between 25 per cent and 42 per cent from 2007 levels in the industrial, commercial and residential sectors.

In the transport sector, FortisBC could achieve 0.3 Mt of domestic reductions and 10.7 Mt from international shipping by 2030. This highlights the significant potential for the gas system to be a key contributor to the province's climate objectives. Ambitious provincial incentives and other policy support would be required to expand the supply of low-carbon gas to this scale. But, maintaining a role for gas within a low-carbon transition ensures that customers maintain their choice of energy supply and lowers the technology risk and costs of a narrowly defined abatement pathway. Such a pathway would also ensure that provincial energy resources and infrastructure are leveraged for a made-in-BC solution.

Growing BC's low-carbon fuel sector will require a number of actions from the province:

- sidentify RNG as an essential component of the province's clean growth pathway
- address regulatory barriers to expanding utility investment in RNG projects
- streamline regulations to enable RNG production from agricultural waste
- provide support to advance the commercial production of hydrogen as a form of RNG

Domestic carbon reductions from international shipping of

10.7

metric tonnes

What is Renewable Natural Gas?

Renewable Natural Gas (RNG) is a carbon-neutral energy source, because it does not contribute any net carbon dioxide into the atmosphere. RNG is produced in a different manner than conventional natural gas. It is derived from biogas, which is produced from decomposing organic waste from landfills, agricultural waste and wastewater from treatment facilities. The biogas is captured and cleaned to create carbon-neutral RNG.

Peter Schouten, Owner Operator, Fraser Valley Biogas. One of FortisBC's first RNG suppliers.

Cleaner vehicles

Displace higher carbon fuels by expanding BC's natural gas vehicle sector

Commercial transportation accounts for 25 per cent of total greenhouse gas emissions in British Columbia and more than half of these emissions originate from road freight transport. By increasing our efforts to displace higher carbon fuels in the heavy-duty vehicle and marine transport sectors, BC can achieve substantial emissions reductions.

By converting heavy-duty truck fleets and transit vehicles to LNG or CNG, we're helping the province meet its carbon emission reduction goals while helping operators save on fuel costs.

FortisBC natural gas for transportation customers are realizing anywhere from 25 to 60 per cent reduction in fuel costs. This helps improve the competitiveness of our private and public sector partners. Since initiating our efforts to introduce cleaner vehicles in 2010, we have reduced more than 110,000 tonnes of CO_2e and displaced more than 145 million litres of diesel.

Natural gas can reduce GHG emissions by up to 30 per cent compared to diesel and gasoline. Additionally, switching to natural gas fuel can improve air quality: natural gas vehicles emit virtually no particulate matter, and they emit up to 95 per cent less nitrogen oxides (NOx).

FortisBC recommends the following actions:

- continue supporting investment in CNG transit vehicles and fueling infrastructure to displace higher carbon fuels and reduce particulate emissions
- expand the GGRR and develop a BC Ports incentive program to convert the 1,700 trucks in BC's drayage sector to CNG or CNG/Hybrid trucks, covering the full cost of the vehicle and reducing both the particulate and GHG emissions associated with BC's ports
- expand eligibility for BC's CEV Specialty-Use Vehicle Program to include hybrid vehicles that include an alternative fuel, such as CNG or hydrogen
- undertake a review of Ministry of Transportation policy to permit low emission natural gas and hydrogen vehicles to use designated HOV lanes on key trade corridors such as Highway 99 and Highway 1

UPS' commitment to CNG

Earlier this year, we partnered with the world's largest package delivery company to launch a compressed natural gas fueling station and vehicles in Vancouver, BC. Seven CNG highway tractors and 40 delivery trucks were added to the current Canadian UPS fleet of over 2,900 package cars, tractors and shifters. Presently, more than 40 per cent of the UPS fleet in Canada runs on alternative fuels. UPS Canada now joins over 800 transit buses, commercial vehicles and freight vehicles powered by natural gas here in BC.

Transform the light-duty transportation sector through electrification

The light-duty transportation sector accounts for 14 per cent of BC's total GHG emissions. This includes light-duty passenger vehicles and trucks that use gasoline or diesel. Electrification of this segment provides a promising pathway to reduce emissions, as cost and performance of the underlying battery technology has seen dramatic improvements in recent years. The automotive industry is responding with many new electric vehicle models arriving in the showrooms of almost every manufacturer.

Growth in the electric vehicle segment is happening in BC but further incentives will be required to achieve government's goal of 5 per cent of all new light-duty vehicle sales. EV sales in 2017 increased by 53 per cent compared to 2016 and were accelerated by an expanding lineup of fully electric vehicles. However, while there has been an increase in the sale of EVs since 2013, at approximately 1.7 per cent of total vehicle sales in 2017 for BC, EV sales are still a small portion of the overall market. FortisBC supports the province's proposal to continue providing vehicle incentives.

Light-duty transportation accounts for

14%

of BC's total GHG emissions

Additional EV charging infrastructure will be critical to advancing the adoption of EVs in the province. Without adequate charging infrastructure deployed throughout the province to allow zero emission vehicles to travel throughout BC safely and conveniently, it is unlikely that the EV market share will progress quickly. Further collaboration between the province, local governments and FortisBC and BC Hydro can address this gap.

We recommend that the province take the following actions:

- continue providing incentives for EV Vehicles and infrastructure
- support increased utility investment in EV charging infrastructure in BC
- leverage existing FortisBC CNG fueling infrastructure to include fast charging EV stations
- develop measures to encourage charging station installations at businesses and other buildings as part of a smart grid

accelerate Kootenays

FortisBC is a core funder of the *accelerate* Kootenays initiative, a collaborative project that will address the charging infrastructure gap across the Kootenay region in Southeast British Columbia. Earlier this year, we opened five electric vehicle Direct Current Fast Charging (DCFCs) stations in the region, connecting the West Kootenays to surrounding regions for electric vehicle travel.

All West Kootenay stations were installed by Kootenay-based electricians, creating local employment opportunities for residents.

All are part of the broader *accelerate* Kootenays initiative which will ultimately facilitate the installation of 13 fast chargers and 40 Level two chargers in communities across the Kootenays, resulting in over 1,800 kms of connected electric vehicle travel. The fast charging stations are critical infrastructure to allow electric vehicle drivers to travel to and through the region, and to facilitate increased adoption of electric vehicles locally.

Buildings & communities

FortisBC is uniquely positioned to be a key agent of the government's strategy to reduce GHG emissions in buildings and communities in a cost-effective, market-driven manner. We provide energy in the built environment through gas, electricity and as an alternative energy provider.

In 2017, we opened the door to our new LEED-equivalent Kootenay Operations Centre outside of Castlegar, BC.

The marketplace recognizes the affordable, high-quality, reliable and safe energy services delivered by FortisBC. Over three million British Columbians use natural gas every day with over 58 per cent of households using natural gas as their primary heating source. The preference for gas is reflected by our continued customer growth. In fact, 2017 was FortisBC's best-performing year for customer growth, with many new customers converting their home heating system from high carbon fuels such as heating oil. This emphasizes the foundational role of gas infrastructure in BC's energy system. To achieve the provincial government's GHG reduction objectives, consumer preference for gas as a low-carbon and affordable energy source should be recognized and harnessed.

Even though customer additions to FortisBC's gas system were at record-levels in 2017, the amount of gas used on a per customer basis declined by 1.8 per cent in 2017 on a weather normalized basis. This speaks to the success of energy efficiency measures in the province including FortisBC's energy conservation programs, federal and provincial policies and the gradual but concerted shift in the built environment to more energy efficient dwellings.

The unique aspect of the gas system is that it is specifically designed to address heating demand. Seasonal changes in heat demand (referred to as "peak load" or "peak demand") can be up to 400 to 500 per cent greater than FortisBC's average demand. For comparison, peak load in the FortisBC electric system is approximately 40 per cent higher than average load. If BC used electricity as the primary source for heat the seasonal variability of heating load would create a huge need for energy storage. Hydropower could meet the storage requirement were it not for the magnitude of heat load in BC. The approximate peak-hour heating load in 2017 in FortisBC's gas system was over 12 GW of electrical capacity equivalent (at a one-to-one unit energy conversion basis). In other words, electrifying heating could require almost a doubling of the existing hydroelectric capacity in BC even before considering the electrification of some part of the transportation fleet or other energy end uses and the additional transmission and distribution requirements. Recognizing this, decarbonizing the gas flowing through the system while maintaining the use of that system is a prudent and low-cost strategy to ensure that BC achieves its climate targets.

Stronger codes and standards over time

We support stronger codes and standards that result in increased energy efficiency. We support an approach that is aligned with the current BC Building Code and BC Energy Step Code (BC ESC) targets. The BC ESC provides an incremental and consistent approach to achieving more energy-efficient buildings in a cost-effective manner while also reducing GHG emissions.

Codes and standards should stay consistent to achieve energy efficiency gains

The BC ESC was developed after an extensive, multi-year engagement process. As a member of the Energy Step Code Council, FortisBC provided insights into the development of the BC ESC, particularly with respect to ensuring affordability needs for British Columbians are addressed, while supporting continuing innovation in the use of energy in buildings.

In addition to supporting long-term improvements in energy efficiency in the BC Building Code, the BC ESC ensures the consistency of building regulations in the province; a key to ensuring clear regulation for builders and developers looking to build in multiple municipalities. The BC ESC provides a provincial framework that replaces the patchwork of different green building standards that have been required or encouraged by local governments in the past. This allows local governments to play a leadership role in improving energy efficiency, while providing a single standard for industry, and build capacity over time.

The BC ESC focuses first on building envelope design with a goal of taking incremental steps to make buildings net-zero energy ready by 2032. It provides for a fuel neutral approach and focuses on the efficiency of buildings and equipment. By focusing on building and equipment efficiency, both overall energy usage and GHG emissions are reduced while building comfort is increased. While costs increase at higher levels of the code, energy usage decreases help offset the increase in overall costs to consumers. The BC ESC also provides flexibility to meet the changing needs and abilities of local governments, industry and technologies. It does this by providing local governments with the tools to pursue a long-term vision for the future of energy efficiency of buildings and related climate action initiatives. As a new code structure, the BC ESC, similar to other changes in the BC Building Code, requires time to learn, implement and see results. It is common practice to make changes to the code only every five to seven years to allow the industry and consumers to become familiar with the change.

Adding additional regulations into the BC ESC, such as the proposed GHG intensity (GHGi) requirement, before results of the adoption of the existing BC ESC are understood and realized would be premature and could lead to unintended consequences: higher energy costs, impaired housing affordability and a loss of choice for consumers. The provincial approach should support consumer choice, by allowing designers and builders to continue to choose gas, electricity, or other energy sources for their project. A fuel-neutral approach provides builders with the flexibility to make energy-efficient buildings using all the available technologies along with managing their costs. It also empowers builders and developers to pursue innovative, creative, cost-effective solutions, and allows them to incorporate leading-edge technologies as they come available. We believe that committing to the current

BC ESC is a prudent measure accounting for the scale of change that the new code presents to the market and the importance of aligning the code across the province.

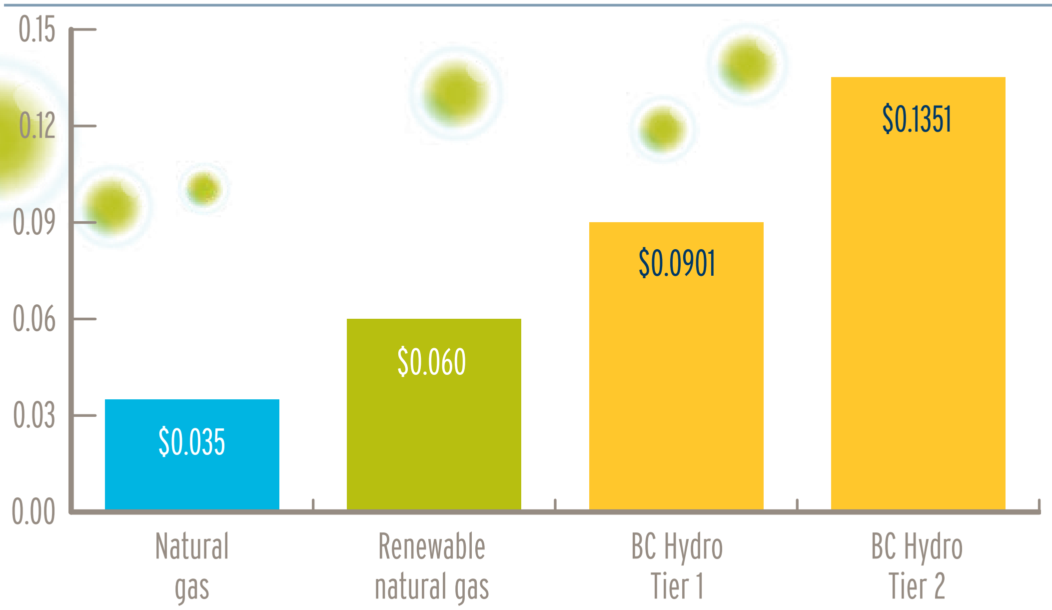
FortisBC has been, and continues to be, a strong advocate for the use of the BC ESC. For example, FortisBC and the City of Vancouver signed a Memorandum of Understanding (MoU) which ensured that the City would introduce pathways that used the BC ESC for builders to comply with the City's Zero Emissions Building Plan. Under these compliance pathways, builders can choose to follow the BC ESC without additional requirements such as a GHGi target. FortisBC also committed to developing a DSM program based on the BC ESC in the MoU. By having new pathways aligned with the BC ESC, FortisBC could provide DSM incentives to lower the costs of achieving the BC ESC to builders in Vancouver while still achieving meaningful improvements in the energy efficiency and GHG reductions of new buildings. Were the province to allow a patchwork of BC ESC along with municipally-specific GHGi requirements, FortisBC would not be able to provide DSM incentives to moderate the affordability pressures of new ambitious codes that restrict access to the gas system.

BC should seek alignment with national codes and standards to ensure consistency with other jurisdictions as it considers a new code for retrofits. The federal code for alterations to existing buildings should serve as a template for BC, as suggested. Because of the scale of the retrofit challenge, clear goals and objectives need to be identified to ensure that all players in this sector have a role. FortisBC is exploring innovative partnerships to demonstrate building energy retrofits and we believe that large GHG reductions consistent with the province's long-term GHG objectives are possible while still maintaining connection to the gas system.

Finally, we recommend that any further changes to the BC Energy Efficiency Standards Regulation should be aligned with federal standards to ensure consistency for equipment manufacturers. We agree with the Canadian Homebuilders Association that it is likely that manufacturers will focus efforts on areas with the greatest market share, national and international, and BC's initiatives may not be as lucrative to encourage the necessary research and development in comparison to federal approaches.

Maintaining affordability for BC energy consumers

Residential gas $/kWh price comparison



Affordability is the key concern among BC residents and FortisBC customers while producing energy locally is the top policy priority for government to consider. As we transition to a low-carbon economy, care must also be taken to ensure that we pursue cost-effective strategies that will not result in higher costs for energy consumers.

Consumer priorities on energy issues

Earlier this month, FortisBC commissioned Innovative Research Group to conduct a survey on consumer priorities on energy issues. The survey found that:

- **For 42 per cent of respondents affordability is the top priority in their personal energy choices**, followed by the environment (24 per cent) and reliability (22 per cent).
- When it comes to government policy, the top priority is **helping the economy by producing energy locally (28 per cent)**, followed by affordability (27 per cent), with environment third (21 per cent).

The survey was conducted between August 3 and 14, 2018 among a sample of 1,328 randomly-selected British Columbians. The survey used a mixed-method online and phone methodology. Interviews in English (n=1,024) were conducted using a representative online panel and in-language interviews in Cantonese, Mandarin, and Punjabi (n=304) were conducted over the phone. Results were weighted to a sample size of n=1,200 based on age, gender, region of the province and mother tongue.

We also believe that regional differences in BC should be taken into account. For example, policies that restrict choice will disproportionately impact energy consumers outside of the Lower Mainland and Southern Vancouver Island that reside in BC's colder regions. Similarly, regions that rely on B.C.'s natural gas industry to drive the provincial economy, should also be taken into account.

FortisBC's RNG, while more expensive than natural gas, is still approximately half the price of electricity in BC and with a lower carbon intensity. This demonstrates the potential for the gas system to achieve significant, affordable GHG reductions with low-carbon drop-in fuels such as RNG and hydrogen. To achieve this potential, supportive policies that provide incentives and opportunities to invest in low-carbon gas supply will be needed over the long-term. These investments will only happen as long as the gas system remains a viable productive asset and consumers have the choice to continue to connect to and use gas.

It is for all these reasons that we believe an approach that targets increased energy efficiency and allows for consumer choice and innovation is consistent with the broader government objectives: making life more affordable and growing the BC economy while taking action on climate change.

Incentives tied to energy efficiency and building improvements

We support increasing energy efficiency incentives. FortisBC is seeking to significantly expand energy efficiency investments in our DSM portfolio. Our proposal currently before the BCUC includes more than doubling energy efficiency spending from 2016 levels by 2019 and with further increases over the next four years. By 2022, we are committed to investing more than $96 million annually, approximately tripling our 2016 spending.

Committed to investing more than

$96 million

annually by 2022

FortisBC estimates that this increased funding would effectively double annual natural gas energy savings and GHG emissions reductions, with the majority of savings occurring in the built environment. Annual energy savings would be in the order of 1 million GJ of gas which will in turn lead to reductions in GHG emissions of approximately 50 thousand tonnes of CO_2e per year.

We are also seeking approval to expand our electricity DSM portfolio. In our 2019 to 2022 DSM Plan, which is currently before the BCUC for review, we are seeking a 21 per cent spending increase over what we put forward in our Long-term DSM Plan. We expect to achieve 17 per cent more energy savings than set out in the long-term plan, or 130 GWh over the plan period.

Through assisting customers in moving to higher-efficiency equipment, supporting the BC ESC and advancing energy conservation in BC overall, our expanded energy efficiency programs will positively impact the province and support the achievement of BC's GHG emissions reduction goals. These measures will also support the BC government's commitment to improving affordability: individual customers will reduce their energy consumption and their energy bills.

FortisBC is supportive of the proposal to develop an incentive program to complement existing utility-led energy efficiency programs focused on retrofits. We believe that if utility and provincial actions are well-designed, they could leverage each other and strengthen participation. We advocate for the provincial government to continue to work closely with utilities in designing this program.

Advanced Metering Infrastructure (AMI) is a valuable tool in helping our customers across BC improve energy efficiency and reduce GHG emissions in residential and commercial buildings. This technology is providing FortisBC's electric customers with more control over how they use energy. To date, we have installed over 134,000 AMI meters in our electric service territory and we seek to extend these benefits to our natural gas system. This technology is the foundation of a more modern natural gas system that improves the customer experience by empowering them to access data to make informed decisions about their energy use. With advanced meters our natural gas customers will have the information they need to inspire mindful choices like using digital control to better manage use of heating appliances or making energy efficiency upgrades to their homes. This technology could also help facilitate more investment in behind the meter solutions by identifying buildings well suited to energy efficiency upgrades and integrating those solutions to the broader system to maximize energy efficiency gains. We recommend that the provincial government provide support for wider deployment of AMI across BC's natural gas network.

Support for low-carbon innovation

FortisBC is well-positioned to identify innovation investments to reduce the carbon footprint of BC's energy system. FortisBC is interested in investing in core research focused on opportunities relevant to BC. This could include ultra high-efficiency gas-fired heat pumps, hydrogen production technologies, measures to reduce the carbon intensity of natural gas such as carbon capture and storage, and near zero GHG engines in vehicles. Without innovation funding from FortisBC or other agencies focused specifically on addressing GHG emissions within BC's unique energy system and fully integrated gas supply, transitioning the gas system to align with the provincial climate targets will be even more challenging.

We recommend that the province consider mechanisms for utility-led innovation investment aimed at reducing GHGs or directing a portion of Innovative Clean Energy (ICE) funding to utility-led projects.

FortisBC also seeks to expand BC's supply of clean energy. Wood and forest residues could significantly expand the amount of RNG supply in BC but, to unlock this potential, focused support for innovation from the public and private sectors will be needed. Of the total supply potential for RNG, wood has the largest share representing approximately 50 per cent of natural gas consumption in Canada. There are a number of other co-benefits of harnessing the potential of wood feedstocks for RNG. These include reducing GHG emissions in BC's forestry-based industries while providing them with new, meaningful financial benefits. This could increase the competitiveness and international market share of Canadian forest industries and boost employment in the sector. However, there are still important technological gaps and high costs associated with wood-based RNG production meaning that, to-date, there has been limited RNG production from wood. The provincial government should identify RNG from wood feedstocks as a key priority for its innovation and climate objectives and work with the forestry sector, FortisBC and the research community to realize this opportunity.

We are supportive of new policies that will support utility investment to broaden our supply of clean energy to include new forms of alternative energy. For example, FortisBC Alternative Energy Services (FAES) is a leader in providing cost-effective, high-performance thermal energy solutions (TES) in BC's building sector. For example, our Marine Gateway and Telus Gardens energy systems in Vancouver, both use renewable and recycled energy to improve efficiency and emissions by 50-80 per cent compared to conventional systems. To date, FAES has invested more than $62 million in high-efficiency energy systems which we own and operate on behalf of our customers.

To date, FAES has invested more than
$62 million
in high-efficiency energy systems

In order to accelerate FAES' contribution to providing highly efficient and low-carbon energy systems, we propose that government support a move to facilitate adoption of a regulated pooled cost model for TES providers. This recommendation would ultimately lead to faster market adoption of TES solutions.

Another example of low-carbon, FortisBC-led innovation is the proposed Ellison Community Solar Pilot project that could be the largest utility-owned solar project in BC. Interest in solar is on the rise and we seek to provide an easy, affordable option for our customers who want to use solar energy to meet a portion of their electricity needs. Our aim is to develop a solar program for customers who are interested in solar, but the upfront cost, placement, operation or maintenance of a rooftop system is not desirable. The province should create opportunity for future utility investment in clean energy projects where there is consumer demand for these offerings.

Energy efficiency labelling information

FortisBC supports the province's goal to improve information for building owners and residents on the energy performance of buildings. As the province develops this program, total energy consumed, carbon footprint and overall cost should all be included in the energy labeling information. FortisBC looks forward to working with the province to further develop this proposal.

A clean growth program for industry

Industry is an important part of the Provincial economy and our customer base. Of FortisBC's 1 million customers, less than a thousand are industrial clients, yet these firms consume approximately one-third of FortisBC's total gas demand. To these customers, gas is a low-cost, efficient, reliable and high-quality fuel source. FortisBC is proud to be the energy supplier of choice to the industries that propel BC's economy.

FortisBC agrees with the provincial government that reducing GHG emissions must happen alongside a strengthening economy. Reducing GHG emissions through investment, technology and sustainable growth must be fostered in a framework to ensuring BC's businesses and industries are not put at a competitive disadvantage. The intention to develop an effective Clean Growth Program for Industry is an important objective of the provincial government. To this end, we believe that an incentive-based approach for industry is an important development.

We also believe that BC needs to be in alignment with the rest of Canada. The federal government's output-based system in the Carbon Pricing Backstop provides more relief to industry while still maintaining the same marginal incentive to reduce GHG emissions. BC should commit to reviewing and evaluating outcomes from the two systems. If the federal approach demonstrates better outcomes for emissions and the economy, then BC should adopt this system to create a level playing field for industries across Canada.

Industrial incentive

We believe that setting the performance benchmark at the level of the cleanest facilities in the world is an ambitious but achievable starting point as many industries in BC are already world-leading environmental performers. Because the Clean Growth Program for Industry aims to improve the international competitiveness of BC's industries, we support the benchmark level as the best performing international firm or facility.

Industries within BC or Canada should not be used to set the benchmark. This would force domestic firms to compete against each other and incur costs with no impact on their international competitiveness. As provincial carbon policy costs begin to align under the Pan-Canadian Framework, the incentive for domestic firms to reduce their carbon emissions is evened. In fact, BC's approach to tax all of a firm's carbon emissions up to $30 per tonne applies significantly more carbon costs than the approach used in the federal output-based allocation system which applies the carbon price only on emissions above the benchmark. This means that even with an aligned price on carbon, BC firms would be disadvantaged compared to other provinces.

A Canadian first

Climate change is a global issue, and FortisBC is committed to being part of the solution. One of the ways we're doing this is by exporting liquefied natural gas (LNG) to countries like China that are looking to significantly reduce their greenhouse gas emissions.

Late last year, FortisBC notched a milestone by delivering the first shipment of LNG from Canada to China. Since then, our shipments have continued, with the most recent one arriving in Shanghai in May.

As China's LNG imports continue to increase, analysts predict it could one day eclipse Japan as the world's biggest importer of natural gas. This presents a unique opportunity for FortisBC, which has the only two LNG storage facilities on Canada's West Coast.

FortisBC's LNG facility in Delta, B.C. has been operating since 1971 and in order to meet the growing demand for LNG it recently underwent a $400-million expansion.

This market shift is about more than just an economic opportunity for Canada. Underlying this trend is the fact that natural gas is a strong energy option for countries like China that are looking to transition from high-carbon fuels to cleaner and more affordable alternatives.

FortisBC offers an abundant supply of LNG that meets high environmental standards. In fact, when FortisBC's Tilbury LNG plant expansion is operational later this year it will be one of the cleanest LNG facilities in the world.

The additional GHG reduction that would be achieved by using domestic firms for the performance benchmark is marginal while simultaneously not improving the competitive position of BC firms in the international market. Because BC's firms compete for market share against international firms, ensuring that carbon costs are moderated compared to the next best international performer should be the key objective. We believe this makes both economic and environmental sense. Incentivizing firms to achieve the lowest carbon intensity than the next best global performer ensures that carbon leakage is minimized while firms in BC are allowed to grow.

The provincial government should use a consistent approach when setting the benchmark across all industries. This means that determining the benchmark for incumbent industries such as mining and pulp and paper should be the same as for nascent industries such as LNG exports. A consistent approach ensures industries of the future can compete for global markets just as todays industries can. FortisBC also supports the principle of consistency regarding the threshold to enter the program at 10,000 tonnes of annual GHG emissions. This will ensure that all large industries can access carbon tax incentives. The government should monitor this threshold and consider opportunities for smaller firms to opt-in to the program.

A threshold of
10,000
tonnes
will ensure all large industries can access carbon tax incentives

The threshold and the benchmark should also account for all emissions whether from combustion, process or fugitive. Firms that demonstrate real investments in technologies and practices that reduce process and fugitive emissions should be able to report those savings toward their emission intensity.

Clean Industry Fund

FortisBC supports the creation of the Clean Industry Fund as a way to invest carbon revenues into direct emissions reductions and innovation in low-carbon technologies. The fund should only be available to firms that are participants in the Clean Growth Program. The fund should be additional to existing government funds for innovation and technology and focused on industrial improvements. The scope for funding should be broad and include direct facility-level improvements, research and development, pilots and demonstrations and projects across the energy supply chain that will lower the carbon intensity of fuels. FortisBC anticipates that it would be a recipient of funds to develop leading technologies in, for example, efficiency, RNG and hydrogen that would improve the carbon intensity of industrial clients.

Investments from the fund should allow projects that achieve both short and long-term GHG reductions and be fuel neutral. A common and agreed framework to evaluate proposals that emphasized cost-effective short term reductions or long-term projects with high reduction potential should be negotiated with Clean Growth Program participants.

FortisBC believes that the government should target industry specific reductions along with system-wide initiatives that could reduce the carbon intensity of all industries. A priority list of actions could be developed in consultation with industry to earmark fund dollars for high-payoff strategies. We believe that one such strategy is to support clean gaseous fuels such as RNG and hydrogen. A specified and focused tranche of support from the fund could have an outsized role to improve the carbon intensity of all industries in BC.

(18-249 08/2018)

Appendix B

COMPLIANCE WITH PAST DIRECTIVES

Appendix B1

TABLE OF CONCORDANCE

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-79-14 – FEI 2014 Core Market Administration Expense Budget					
1.	10	2	***CMAE Budget Review:*** The Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications. …The Panel directs that the CMAE Budget review and approval process be included within the FEI revenue requirements application starting with the next such application filed by FEI.	Completed.	See Appendix B4.
G-138-14 – FEI Multi-Year Performance Based Ratemaking Plan for 2014 to 2019					
2.	82	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	The study has been completed and was reviewed with BCUC staff and interveners on November 13, 2018. The study is included in this Application.	See Appendix C2-1.
G-86-15 – FEI Annual Review for 2015 Delivery Rates					
3.	19	14	***Safety Service Quality Indicators*** The Panel agrees with BCSEA that a five-year rolling average of Leaks per KM of Distribution System Mains would be helpful information and directs FEI to provide this information in future annual reviews. The Panel also agrees that with regard to the SQI Public Contact with Pipelines, the number of line damages and the number of calls to BC One Call would be helpful and directs FEI to also provide this information in future annual reviews.	Ongoing during PBR period	Final 2018 SQIs are provided in Appendix C5-1; 2019 SQIs will be provided in a separate filing.
4.	19	15	***Historical Service Quality Indicators*** FEI is directed to provide SQI results from 2009 onward for future annual reviews.	Ongoing during PBR period	Final 2018 SQIs are provided in Appendix C5-1; 2019 SQIs will be provided in a separate filing .

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
5.	19	16	***Transmission Reportable Incidents Service Quality Indicator*** For subsequent annual reviews, FEI is directed to report the number of Transmission Reportable Incidents in each of the severity levels.	Ongoing during PBR period	Final 2018 SQIs are provided in Appendix C5-1; 2019 SQIs will be provided in a separate filing.
6.	19	17	***GHG Emissions*** With regard to including the Estimated Annual GHG Emissions (in tCO2e) reported by the Company to the Ministry of Environment, the Panel has no objection, and directs FEI to provide this information in future annual reviews.	Ongoing during PBR period	Final 2018 SQIs are provided in Appendix C5-1; 2019 SQIs will be provided in a separate filing.
7.	34	28	***Reporting on Initiatives during PBR Term*** The Panel directs FEI to continue to provide in each annual review application the information that was provided in response to BCUC IRs 1.2.9 (Regionalization Initiative) and 1.3.3 (Project Blue Pencil) and to update these tables for actual results as this data becomes available. The same analysis is to be performed on new initiatives that are implemented during the PBR term.	Ongoing during PBR period	See Appendix B6.
8.	35	30	***Number of Employees*** The Panel directs FEI to include in its annual review filings both the total year-end number of employees and the total year-end number of Full Time Equivalent Employees.	Ongoing during PBR period	See Appendix B7.
G-119-16 – FEI PROPOSAL FOR DEPRECIATION AND NET SALVAGE RATE CHANGES					
9.	7	2	***Depreciation Study*** The Panel directs FEI to provide as part of its next Depreciation Study an analysis of the costs and benefits of converting from the Average Service Life group depreciation method to the Equal Life Group depreciation method, including calculations of the rate impact. FEI is also directed to include a discussion of the group depreciation method used by each of the major regulated gas utilities in Canada.	Completed.	See Section D2 for analysis and discussion.

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-133-16 – FEI BIOMETHANE ENERGY RECOVERY CHARGE RATE METHODOLOGY					
10.	45	12	***Unsold Biomethane Premium Deferral Account Implementation*** In order to provide the transparency directed in the 2013 Decision the Panel directs that the recovery of the BVA balance be through a rate rider from FEI's non-bypass customers, effective January 1st of the subsequent year (BVA Rate Rider). Furthermore, the continuation of the FEI BVA Balance Transfer mechanism will be reviewed in the earlier of four years or an application for an inventory transfer from the BVA to the MCRA, or FEI's approach to ratemaking (i.e. PBR to cost of service).	Completed.	See Appendix B9.
G-182-16 – FEI ANNUAL REVIEW FOR 2017 RATES					
11.	19	8	***Forecasting Directive*** FEI is directed to report the Holt's Exponential Smoothing (ETS) test forecasts and the aggregate Mean Average Percent Error (MAPE) results as part of its annual review for 2018 delivery rates application and in all remaining annual review applications. FEI is also directed, as part of its future annual review application materials, to extend the applicable tables in Section 3 of Appendix A2 of the Application to include variance information for the ETS method for the residential and commercial use per customer, and the commercial customer additions.	Results reported.	See Appendix B2.
G-25-17 – FEI ALL INCLUSIVE CODE OF CONDUCT AND TRANSFER PRICING POLICY					
12.	24	4	***Shared Services*** FEI is directed to file a review of its shared services model as part of its 2018 Annual Review under its Performance Based Rate Plan or alternatively, as part of its next revenue requirement proceeding.	Completed.	See Section D4.
G-196-17 – FEI ANNUAL REVIEW FOR 2018 RATES					
13.	10	-	***Capital Spending in Excess of the Dead-Band*** Given the ongoing issues with capital spending, the Panel directs FEI to continue to report on capital spending in the manner outlined in the FEI Annual Review for 2017 Delivery Rates Reasons for Decision, attached as Appendix A to Order G-182-16, for the remainder of the PBR term. These capital reporting requirements must include updating the information in Table 1-4 provided in the Application as well as updating the information in Appendix C4 to the Application.	Ongoing during PBR period.	See Appendix B8-1.

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-169-18 – FEI EVACUATION RATE RELIEF SECTION 63 EXEMPTION					
14.	2	3	***Evacuation Rate Relief*** FEI is directed to report on the impact of the evacuation bill relief on the 2018 revenues and costs in its next Annual Review of Delivery Rates application.	Completed.	See Appendix B5.
G-237-18 – FEI ANNUAL REVIEW FOR 2019 RATES					
15.	8		***TIMC project and development cost deferral account*** The Panel directs FEI to file the following information in its next revenue requirements application, which is expected to be filed sometime in 2019: 1) Updated actual and forecast project development costs compared to budget with explanations for variances; 2) Updated timeline for when FEI anticipates filing the CPCN with explanations for changes; and 3) Details on project scope and delivaables, including any changes thereto from what was provided in the current annual review proceeding.	To be reported on in FEI's 2020 rate setting application.	N/A
16.	14		***Report on Initiatives During the PBR Term, Report on Headcount and FTE Information, Capital Directive and Capital Expenditures 2014 to 2018*** The Panel directs FEI to file the information contained in Appendix C2, C3 and C4 of the Application, as well as Table 1-4 of the Application, as part of FEI's upcoming revenue requirement application. The Panel expects that this information will be updated to include the actual 2018 results, if available, and projected 2019 results.	Completed.	See Appendix B6 – Report on Initiatives During the PBR Term; Appendix B7 – Report on Headcount and FTE; Appendix B8-1 – Capital Directives .

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-139-14 – FBC MULTI-YEAR PERFORMANCE BASED RATEMAKING PLAN FOR 2014 TO 2019					
1.	80	29, 30, 31	***Benchmarking Study:*** The Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018. In order to avoid a clash of methodologies as was experienced in this Proceeding, the Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study. Fortis is directed to report the results of this consultation to the Commission prior to starting the study.	The study has been completed and was reviewed with BCUC staff and interveners on November 13, 2018. The study is included in this Application.	See Appendix C2-2.
G-169-14 – FBC ADVANCED METERING INFRASTRUCTURE (AMI) ENABLED BILLING OPTIONS FOR CUSTOMERS					
2.	n/a	5	***AMI Deferral Account*** FBC must report these incremental costs and savings in each of the annual reviews during the Performance Based Ratemaking term.	Ongoing during term of PBR.	Final 2018 and 2019 results will be reported in Annual Review filings.
G-107-15 – FBC ANNUAL REVIEW FOR 2015 RATES					
3.	15	n/a	***Advanced Metering Infrastructure (AMI) Theft Reduction*** The Commission Panel directs FBC to include, in its next and subsequent annual PBR reports, the impact of AMI on losses through theft deterrence. This directive will improve regulatory efficiency in the review of FBC's proposed actions (and FBC's incentives to undertake these actions while under PBR) related to the reduction of theft related costs. The information to be submitted should include: (i) a comparison of the projected GWh reduction for the test year and proceeding years to the estimated GWh theft reduction assumed in the AMI decision for those years; and (ii) a description of FBC's operational activities and costs incurred in reducing electricity theft (for example, related to FBC's Revenue Protection Program) and the regulatory treatment of these costs.	Ongoing during term of PBR.	Final 2018 and 2019 results will be reported in Annual Review filings.

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-8-17 – FBC ANNUAL REVIEW FOR 2017 RATES					
4.	15	5	***Ruckles Substation Rebuild Project:*** The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the Ruckles Substation Rebuild project: • The status of the Ruckles project, including a comparison of the project timeline provided in the current Application to the updated project timeline, as at the time of filing each annual review application. • Updated cost estimates and scope descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the Ruckles project as at the time of filing each annual review application. • The final actual project cost, including a description of the scope of work completed relative to the cost estimate and scope description provided in the Application, with explanations for any variances.	Ongoing during term of PBR.	Final Ruckles Substation report will be provided in the Annual Review for 2020 Rates filing.
5.	21	6	***Upper Bonnington Old Units Refurbishment Project:*** The Panel directs FBC to report in each of its annual review applications during the remainder of the PBR term the following information on the UBO Refurbishment project: • The status of both the UBO Refurbishment project as a whole and of the individual units, including a comparison of the project timeline provided in the current Applicaton to any updated project timeline as at the time of filing each annual review application. • Updated cost estimates and cost descriptions compared to the cost estimates and scope descriptions provided in the current Application, including explanations for any variances/changes to the cost estimates or project scope. • Actual costs incurred to date on the UBO Refurbishment project as a whole and on each individual unit as at the time of filing each annual review application. • Final actual refurbishment costs at the completion of each unit, including a description of the scope of work completed relative to the conditions found and against the cost estimate.	Ongoing during term of PBR.	Reports will be provided in Annual Review filings.

No.	Decision Page No.	Directive No. or Reference	Description / Details	Status	Section in this Application
G-9-18 – FBC Application for Approval of Rate Design and Rates for Electric Vehicle Direct Current Fast Charging Service					
6.	2	2	***Electric Vehicle DCFC stations*** FBC is directed to separately track and account for all costs associated with the EV DCFC stations and exclude all such costs from its utility rate base until the Commission directs otherwise.	Confirmed that EV DCFC Stations costs and revenues will be excluded from rate base until otherwise directed.	N/A
G-38-18 – FBC Annual Review for 2018 Rates					
15.	17	8	***Updated System Loss Study*** FBC is directed to file its updated system loss study in its application for rates effective January 1, 2020 following the end of the current PBR term.	Completed.	See Appendix B3.
G-170-18 – FBC Evacuation Rate Relief Section 63 Exemption					
16.		3	***Evacuation Rate Relief*** FBC is directed to report on the impact of the evacuation bill relief on the 2018 revenues and costs it its next Annual Review of Delivery Rates application.	Completed.	Report on Evacuation Bill Relief revenue and cost impact provided in Section B5.
G-246-18 – FBC Annual Review for 2019 Rates					
17.	14	3	***Capital Expenditures 2014 to 2018*** FBC is directed to continue providing the information related to capital that is in Table 1-3 and Appendix B2 of the Application in its next revenue requirements application, which is expected to be filed with the BCUC in 2019.	Completed.	See Appendix B8-2.
18.	15		***Loss Recovery Request*** The Panel directs FBC to provide forecast Loss Recoveries in future revenue requirements applications.	Loss recoveries will be forecast in future revenue requirements applications.	N/A
19.	17		***SQI Performance*** The Panel takes note of the potential decline in SAIDI performance created by the implementation of the OMS, and encourages FBC to incorporate the impact of OMS in setting a future benchmark for SAIDI.	Completed.	See section C3-3.6 and appendix C5-2.

Appendix B2

FEI FORECASTING METHOD STUDY

FEI FORECASTING METHOD STUDY

1.1 *INTRODUCTION*

In this Report, FEI presents the final results of its research in compliance with the BCUC's three directives applicable to FEI's demand forecasting methodology (the Forecasting Directives) in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application.[1] Table A:B2-1 provides a description of the Forecasting Directives.

Table A:B2-1: Order G-86-15 Forecast Methodology Directives[2]

No.	Directive
3	The Panel directs FEI to review alternative methodologies and develop one that overcomes the identified shortcomings and more accurately predicts actual average UPC for the next annual review.
5	The Panel directs FEI to include commercial customers as part of its review of alternative methodologies for forecasting UPC for the next annual review.
8	The Panel directs FEI to consider alternative methods for forecasting commercial customer additions which are appropriately sensitive to the business cycle. FEI is to provide an analysis of these alternatives in its next annual review application.

In compliance with the Forecasting Directives, FEI identified and tested the method called Holt's Exponential Smoothing (ETS) to forecast residential and commercial use rates and commercial customer additions.

The key findings of this Report are as follows:

1. Residential Use Rates - Mainland[3]
    - The average residential demand forecast error from natural gas utilities captured in three separate surveys was 4.1 percent.

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[1] On July 10, 2015, FEI filed a letter with the BCUC requesting approval to extend the filing deadline to April 30, 2016 due to the scope of the work identified by FEI to comply with the BCUC's directives. In Letter L-30-15, the BCUC approved a modification of FEI's request, directing that FEI file its final report on alternative load forecasting methodologies, including FEI's proposed course of action, as part of the annual review of 2017 delivery rates application in September 2016. In addition, the BCUC requested that FEI file a progress report with the BCUC by April 30, 2016, which was filed on April 27, 2016.

[2] In addition, in Appendix A to Order G-193-15 on page 20, the BCUC stated "With regards to the Rate Schedule 23 demand forecast, the Panel is satisfied that the forecasting methodology is reasonable for the purposes of forecasting 2016 demand and reiterates our expectation that this forecasting methodology will be reviewed as part of FEI's overall forecasting methodology review process as directed in the FEI Annual Review of 2015 Delivery Rates Decision and letter L-30-15."

[3] The Mainland region was used for testing forecast performance. Mainland was chosen for testing because the region accounts for more than 90 percent of FEI demand and because the rate schedules for FEI have been stable over time.

- Using its existing method for calculating residential use rates, FEI's mean absolute percent error (MAPE[4]) for the residential demand forecast over the period from 2012-2018 was 2.7 percent.
- Over the same period the MAPE for the residential demand forecast developed using the ETS method for residential use rates was 2.6 percent.

2. Commercial Use Rates - Mainland

- The average commercial demand forecast error from natural gas utilities captured in three separate surveys was 4.1 percent.
- Using its existing method for calculating commercial use rates, FEI's MAPE for the commercial demand forecast over the period from 2012-2018 was 2.4 percent.
- Over the same period the MAPE for the commercial demand forecast developed using the ETS method for commercial use rates was 0.8 percent.

3. Commercial Customer Additions - Mainland

- The average commercial customer additions forecast error from natural gas utilities captured in three separate surveys was 4.1 percent.
- Using its existing method for calculating commercial customer additions, FEI's MAPE for the commercial demand forecast over the period from 2012-2017 was 2.4 percent.
- Over the same period the MAPE for the commercial demand forecast developed using the ETS method for commercial customer additions, was 2.8 percent.

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4 MAPE is the mean absolute percent error across a number ("n") of time periods and is defined as:

$$MAPE = \frac{1}{n}\sum_{t=1}^{n}|PE_t|$$

MAPE eliminates the cancellation effect of positive and negative errors over time. The result of the MAPE calculation is a simple percentage making it easy to compare different forecasts and methods regardless of the underlying units (e.g. customers or demand). MAPE will be used in this Report to evaluate forecast performance.
Percent error (PE) is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

$$PE_t = \left(\frac{Y_t - F_t}{Y_t}\right) \times 100$$

4. Fort Nelson
   - The 2017 forecast was re-forecast using the ETS method in an identical manner.
   - The results followed a similar pattern as described above for the Mainland region.
5. Recommendation
   - Based on the test results, FEI recommends the adoption of the ETS method for residential and commercial use rate forecasting and the continued use of the existing forecast method for commercial customer additions.

The results are discussed in detail in the following sections.

1.1.1 Forecast Performance

The demand forecast for all residential and commercial rate schedules is the product of a customer forecast and a use rate forecast.

FEI created forecasts to test each component (residential use rates, commercial use rates, commercial customer additions) independently. Only one component was changed for each run so that the impact of a single change could be measured. For example, in a residential use rate test all other components of the forecast were unchanged from the forecasts as filed and only the residential use rates were changed. Once each forecast re-calculation was complete, any changes in the absolute percent error (APE)[5] compared to the existing forecast were known to be directly related to the single forecast component that was changed.

In the following sections Mainland and Fort Nelson demand forecasts from each method are compared to the actual demand.

All data is weather normalized as per the methods described in Section 5.1 of Appendix A3 of the 2019 Annual Review.

1.1.1.1 Residential Use Rate

The first four years of Mainland testing demonstrated that both methods were able to achieve similar results while neither method consistently outperformed the other. In the final two years neither model was able to predict the uptick in demand. This is reasonable because both models are based on time series (historical) data.

At the end of seven tests the Mainland MAPE scores for the Existing method was 2.7 percent while the ETS result was almost identical at 2.6 percent.

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[5] APE is the absolute percent error for one measurement and is defined as:

$$APE = |PE_t|$$

Table A:B2-2: Mainland Residential Use Rates

	Year	Data Cutoff	Forecast Demand (PJ)	Actual Demand (PJ)	APE	2012-2018 MAPE
Existing	2012	2010	69.9	69.8	0.2%	
	2013	2010	69.8	68.1	2.5%	
	2014	2012	69.5	68.5	1.5%	
	2015	2013	68.5	68.9	0.5%	1.2%
	2016	2014	67.7	72.3	6.4%	2.2%
	2017	2015	68.5	71.7	4.5%	2.6%
	2018	2016	74.7	72.1	3.6%	2.7%
ETS	2012	2010	68.4	69.8	2.0%	
	2013	2010	67.6	68.1	0.7%	
	2014	2012	68.9	68.5	0.6%	
	2015	2013	67.6	68.9	1.9%	1.3%
	2016	2014	67.8	72.3	6.2%	2.3%
	2017	2015	68.6	71.7	4.4%	2.6%
	2018	2016	70.6	72.1	2.1%	2.6%

The Fort Nelson residential demand results from the 2017 forecast appear in the following table[6]. Given the small sample size and low volumes (less than 1/3rd of a PJ), FEI considers these results to be inconclusive.

Table A:B2-3: Fort Nelson Residential Use Rates

Fort Nelson	Year	Data Cutoff	Forecast Demand (PJ)	Actual Demand (PJ)	APE
Existing	2017	2015	0.262	0.251	4.1%
ETS	2017	2015	0.260	0.251	3.5%

1.1.1.2 Commercial Use Rate

The ETS method performed very well in the period from 2013-2015. While the existing method performed considerably better than the industry average, the ETS recorded an even lower MAPE at 0.8 percent. Both methods responded similarly to the uptick in 2016 and as a result of the time series approach, both under forecast those years. The largest error from the ETS

[6] MAPE column is not shown for any Fort Nelson results because there is only a single test. To develop a "mean" absolute percent error multiple tests are required.

method was 1.7 percent in 2016 while the existing method met or exceeded 3 percent in four different years.

Table A:B2-4: Mainland Commercial Use Rates

	Year	Data Cutoff	Forecast Demand (PJ)	Actual Demand (PJ)	APE	2012-2018 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	2.2%
	2016	2014	49.3	50.8	3.0%	2.3%
	2017	2015	49.7	51.4	3.3%	2.5%
	2018	2016	53.0	52.0	1.8%	2.4%
ETS	2012	2010	48.1	48.8	1.4%	
	2013	2010	48.5	48.1	0.8%	
	2014	2012	48.5	48.8	0.5%	
	2015	2013	49.1	49.1	0.0%	0.7%
	2016	2014	49.9	50.8	1.7%	0.9%
	2017	2015	50.9	51.4	1.1%	0.9%
	2018	2016	52.1	52.0	0.1%	0.8%

The Fort Nelson commercial demand results from the 2017 forecast are presented in the table below. Unlike in the Mainland tests, the commercial scores were nearly identical in Fort Nelson.

Table A:B2-5: Fort Nelson Commercial Use Rates

Fort Nelson	Year	Data Cutoff	Forecast Demand (PJ)	Actual Demand (PJ)	APE
Existing	2017	2015	0.269	0.263	2.2%
ETS	2017	2015	0.268	0.263	2.2%

1.1.1.3 Commercial Customer Additions

Commercial customer additions are more difficult to forecast due to volatility in customer counts. As shown in the following tables, the existing method outperformed the ETS method in five of six years. In two of the five years the error from the ETS method exceeded the industry target of 4 percent. In all the Mainland testing, the industry target was only exceeded twice.

Table A:B2-6: Mainland Commercial Additions

	Year	Data Cutoff	Forecast Demand (PJ)	Actual Demand (PJ)	APE	2012-2018 MAPE
Existing	2012	2010	47.1	48.8	3.4%	
	2013	2010	47.3	48.1	1.6%	
	2014	2012	50.2	48.8	3.0%	
	2015	2013	49.3	49.1	0.5%	2.2%
	2016	2014	49.3	50.8	3.0%	2.3%
	2017	2015	49.7	51.4	3.3%	2.5%
	2018	2016	53.0	52.0	1.9%	2.4%
ETS	2012	2010	46.2	48.8	5.3%	
	2013	2010	46.7	48.1	3.0%	
	2014	2012	50.3	48.8	3.1%	
	2015	2013	48.8	49.1	0.5%	3.0%
	2016	2014	48.4	50.8	4.7%	3.3%
	2017	2015	50.0	51.4	2.9%	3.2%
	2018	2016	51.8	52.0	0.4%	2.8%

The Fort Nelson commercial demand results resulting from commercial customer additions testing from the 2017 forecast appear in the following table. Similar to the Mainland tests, the existing method significantly outperformed the ETS method.

Table A:B2-7: Fort Nelson Commercial Additions

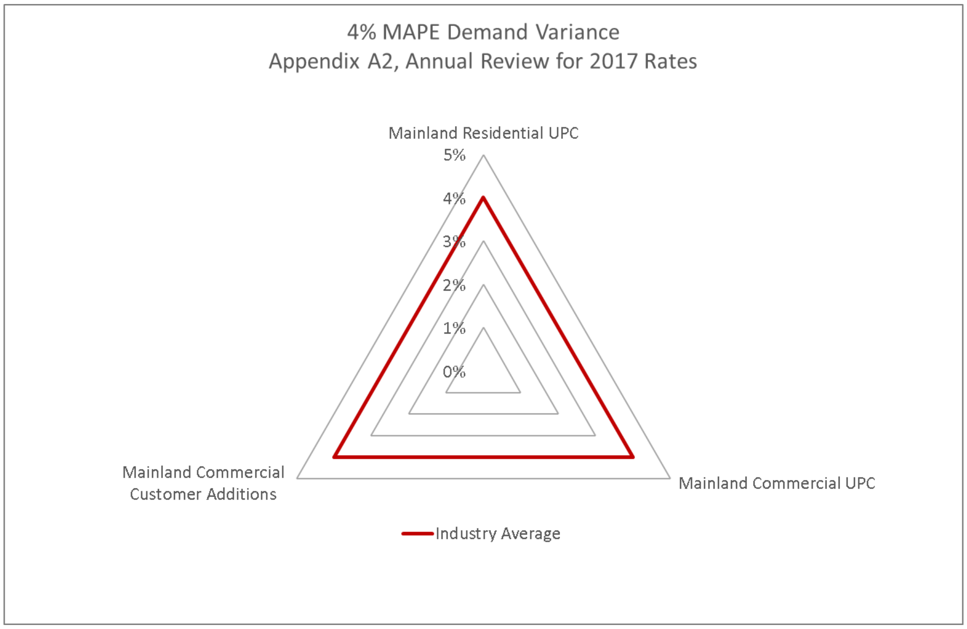
Fort Nelson	Year	Data Cutoff	Forecast Demand (PJ)	Actual Demand (PJ)	APE
Existing	2017	2015	0.269	0.263	2.2%
ETS	2017	2015	0.277	0.263	5.5%

1.1.2 Comparison of Results

FEI presented method comparison results starting with the Annual Review for 2017 Rates in Appendix A2 using a chart format called a "radar plot". The following radar plots show the latest comparison results.

The following radar plot shows the 4 percent zone in red. Starting with the innermost triangle, each increment represents a 1 percent increase in the MAPE. Forecast variances inside the red triangle are better than the industry average as cited in Appendix A2 of the FEI Annual Review for 2017 Rates, while variances outside the triangle are worse. This figure serves as a starting point with which the forecast alternatives can be compared.

Figure A:B2-1: Performance Results – Industry Average

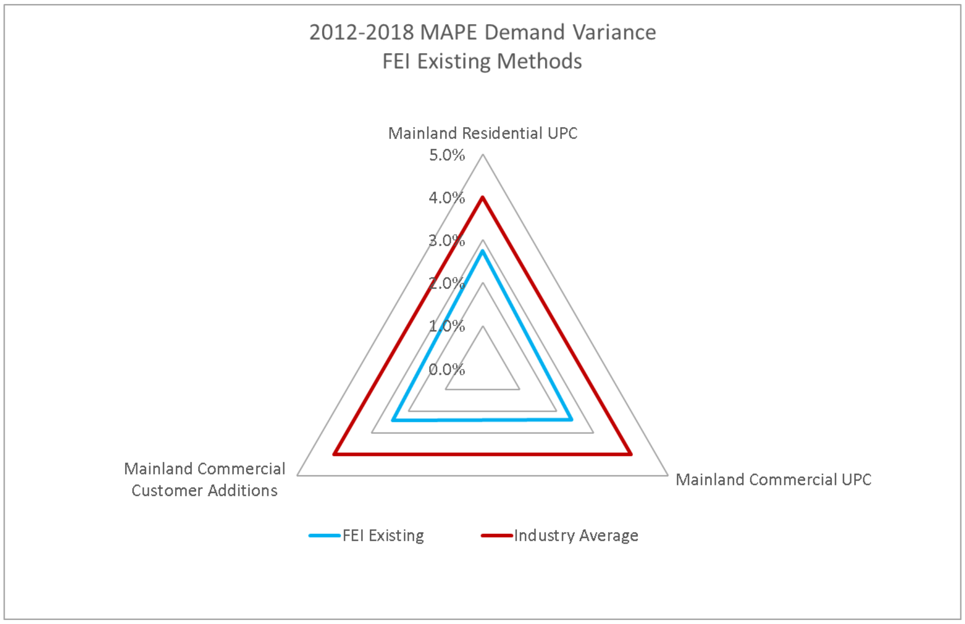


1.1.2.1 Existing Method

In the following figure, the MAPE demand variances recorded by FEI for Mainland customers for the period from 2012-2017 are shown in blue. The ETS testing commenced in 2012, thus establishing the starting point.

As shown, the blue line lies completely within the red line indicating that for the period the FEI residential and commercial demand forecasts based on existing methods outperformed the 4 percent average.

Figure A:B2-2: Performance Results - Existing Methods– Mainland

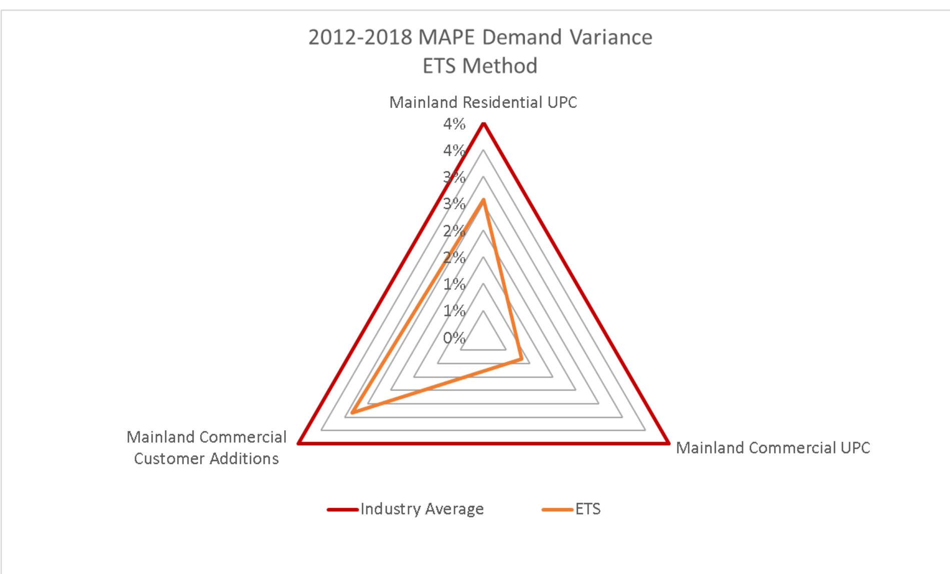


1.1.2.2 ETS Method

In the following figure, the MAPE demand variances calculated by FEI using the ETS method for Mainland customers for the period from 2012-2018 is shown in orange.

As shown, the orange line lies completely within the red line indicating that for the period from 2012-2018 the FEI residential and commercial demand forecasts based on the ETS methods would have outperformed the industry average.

Figure A:B2-3: Performance Results - ETS Method - Mainland

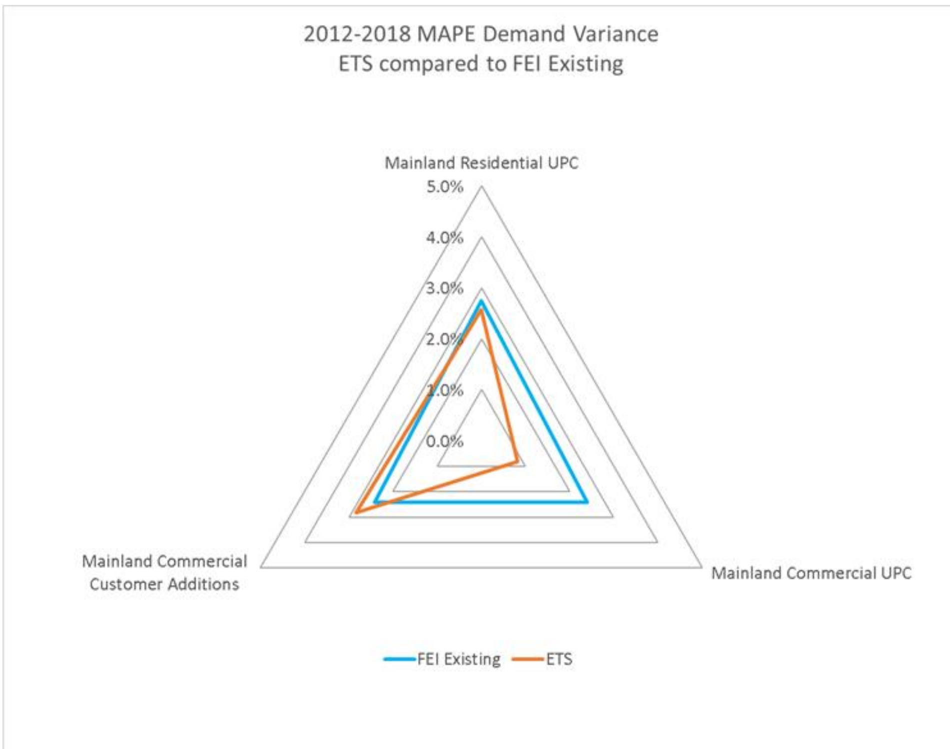


1.1.2.3 ETS compared to the Existing Method - Mainland

From the above analysis, both the existing and ETS methods would result in forecast variances lower than the industry average of 4 percent. FEI has used the following radar plot in recent Annual Reviews to demonstrate how the existing method compares to the ETS method.

- When applied to residential use rates the ETS method performed slightly better than the existing method.
- When applied to commercial use rates the ETS method performed better than the existing method.
- When applied to commercial customer additions the ETS method performed worse than the existing method.

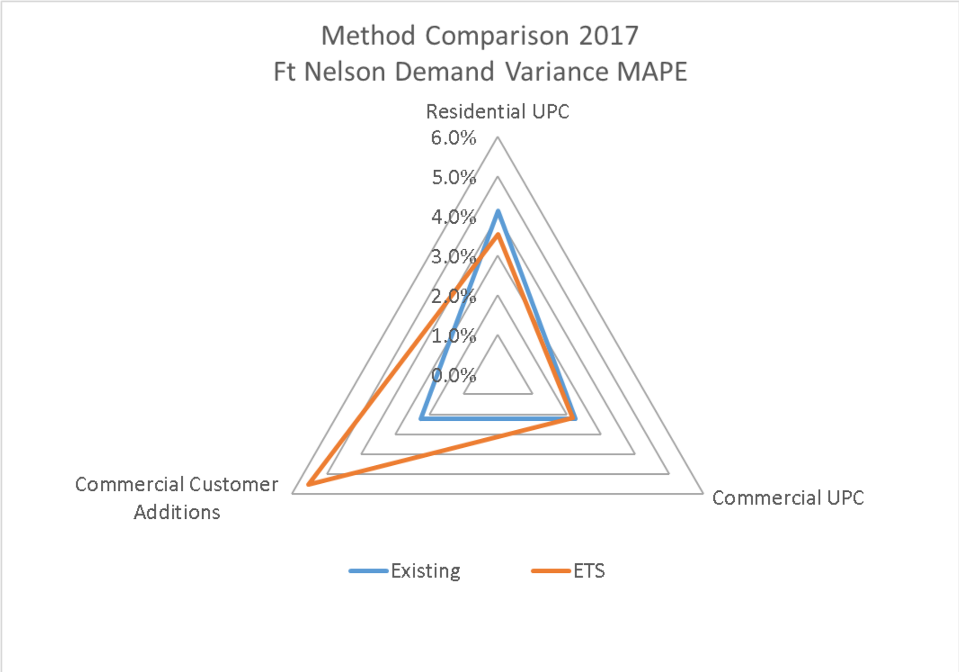
Figure A:B2-4: Performance Results - Method Comparison - Mainland



1.1.2.4 ETS compared to the Existing Method - Fort Nelson

As seen below, the Existing Method for both residential and commercial UPC performed about the same, while the customer addition forecast compiled with ETS performed significantly worse.

Figure A:B2-5: Performance Results - Method Comparison - Fort Nelson

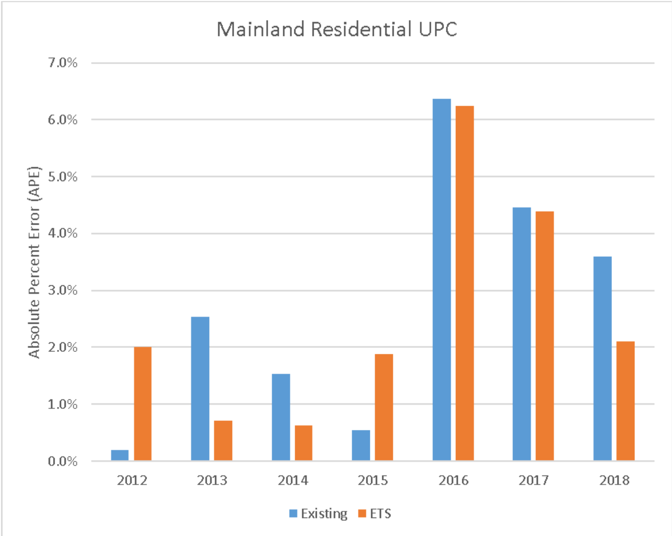


1.1.3 Conclusion

1.1.3.1 Residential Use Rates

As shown in the figure below, neither method had the best performance in each year.

Figure A:B2-6: Method Comparison – Mainland Residential UPC

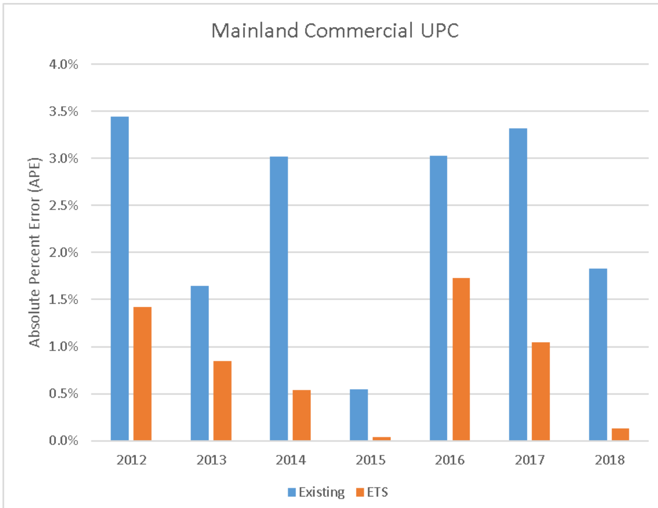


In 2012 and 2015 the existing method performed better than the ETS method. In 2013 and 2014 and 2016-2018 the ETS method outperformed the existing method. This shows that, regardless which method is selected, there will be years where the other method would have performed better.

1.1.3.2 Commercial Use Rates

The ETS method performed the best in every year of the testing. Even in years where the existing method performed well, such as 2015, the ETS method performed better. The ETS method never exceeded half the 4 percent industry average error while the existing method reached or exceeded 3 percent in four years.

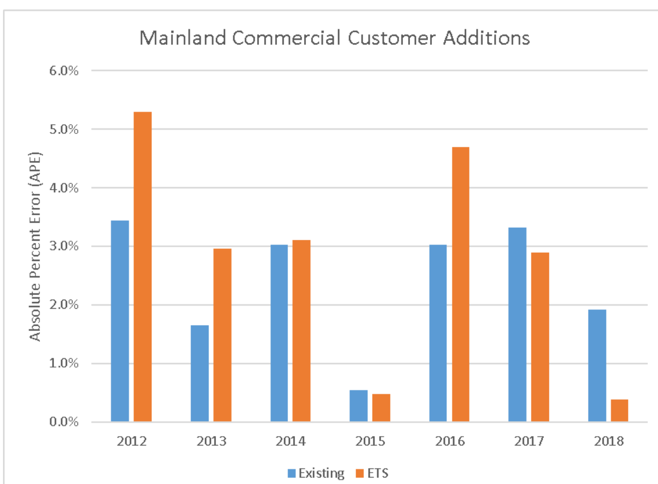
Figure A:B2-7: Method Comparison – Mainland Commercial UPC



1.1.3.3 Commercial Customer Additions

As shown in the figure below, neither method had the best performance each year.

Figure A:B2-8: Method Comparison – Mainland Commercial Customer Additions



In two years the ETS method exceeded the industry average error of 4 percent, while the existing method never exceeded the industry average.

1.1.3.4 Pros and Cons of Existing and ETS Methods

Given the results above, the following tables summarize the pros and cons of each method.

Table A:B2-8: Pros and Cons of the Existing Method

Pros	Cons
Results beat industry average.	Does not use all the available data.
Long term experience in all regions and rates.	
Some sophistication because the method uses a trend if one exists, but defaults to an average if a trend does not exist.	

Table A:B2-9: Pros and Cons of the ETS Method

Pros	Cons
Results beat industry average in most tests.	Limited experience in Mainland regions and Fort Nelson.
Uses all available data. The method calculates dynamic weighting of older data.	No experience in Vancouver Island or Whistler.
Easy to use in Microsoft Excel.	Difficult (impossible) to duplicate the Microsoft result by hand as the algorithms are not published.

1.1.4 Recommendation

The ETS method performed better than the existing method in all commercial UPC tests in all years. When applied to residential UPC forecast, the ETS method and the existing method each had good years and bad, and the final MAPE result was only slightly in favour of the ETS method. In commercial customer additions the methods each had good years and bad, but on two occasions the ETS method exceeded the 4 percent industry average.

Commercial use rates were the only forecast test where one model consistently outperformed the other, and FEI believes this is a critical criterion for recommending a model change.

While FEI notes that Vancouver Island, Whistler and Fort Nelson have not been thoroughly tested, those areas comprise only a small percentage of the overall demand, and there is no reason to believe different results would be achieved for those areas than for the Mainland. As a result, and given the strong performance of the ETS method for forecasting use rates, FEI is recommending switching all residential and commercial use per customer forecasting to ETS, including for the Fort Nelson service area. FEI proposes to continue the use of the Existing method for customer addition forecasting.

FEI is not proposing to continue to run parallel methods in future annual reviews, but will use ETS for use rate forecasting, and will continue to explore the pros and cons of existing methods compared to alternative methods for customer addition forecasting.

Appendix B3

FBC LOSSES STUDY

FBC LOSSES STUDY

1.1 *INTRODUCTION*

This Appendix comprises FBC's 2019 study of system losses (2019 Losses Study).

Energy losses on FBC's electric system, collectively referred to as "system losses", are comprised of technical transmission and distribution losses, losses due to wheeling through BC Hydro's system, unaccounted for energy (including meter inaccuracies and theft), and company use at FBC's facilities and generating plants.

Losses are not measured directly; instead, losses represent the difference between the total energy entering FBC's system (gross load) and the amount of energy consumed through end use. Gross load is calculated on a monthly and annual basis; however, some components of end use energy consumption are measured on a billing cycle opposed to a calendar month, and cannot be accurately measured with the same periodicity as gross load.

FBC's previous study of system losses was conducted in 2012. In its decision concerning the Company's Annual Review for 2018 Rates[1], the BCUC confirmed it was satisfied with FBC's system loss forecast method while noting that FBC was in the process of updating its loss projections. Accordingly, the BCUC directed FBC to submit an updated system loss study in its application for rates effective January 1, 2020.

In this 2019 Losses Study, FBC employed newly-available data from its Advanced Metering Infrastructure (AMI) to improve the degree to which energy consumption can be measured within the relevant reporting period. In most other respects, the 2019 Losses Study is consistent with the 2012 losses study[2]. The results of the 2019 Losses Study confirm the historical losses estimate of 8.0 percent of gross load as reasonable for forecasting and rate making purposes, based on the existing definition of system losses.

The 2019 Losses Study recommends the following:

1. The definition of losses should exclude measured company use, which encompasses FBC facilities including its generating plants.
2. In future applications, FBC's system losses should be forecast at 7.6 percent of gross load as shown in Table A:B3-1 and company use be treated independently in the load forecast.
3. FBC should conduct its next losses study at the end of the MRP term.

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1 Order G-38-18, Appendix A, page 17.
2 The 2019 study excludes an estimate of theft reduction due to AMI implementation as described in Section 2.4.1.2.

In the following sections FBC describes the method used in this 2019 losses study, the previous 2012 losses study method, the results of the study, the limitations, and concluding recommendations.

1.2 LOSSES STUDY APPROACH

In Table A:B3-1 of the results section below, system losses are shown as the difference between gross load and net billable load (NBL) less measured Company Use. This definition of system losses can be represented as follows:

$$Gross\ Load - Net\ Billable\ Load - Company\ Use = \ System\ Losses$$

The notable difference from the existing definition as used in the 2012 losses study is the subtraction of company use.

Conversely, the following equation expresses the components of system losses:

$$System\ Losses = BC\ Hydro\ Wheeling\ Losses + \ T\&D\ Losses + Unaccounted\text{-}for\ Energy$$

Each component of these equations is described below.

1.2.1 Gross Load

FBC's Gross Load is the total system load that FBC must supply. Gross load is a calculated number based on metered generation within the system plus any energy that flows into the system at metered points of interconnection[3]. For accounting and rate-setting purposes, FBC records and forecasts gross load on a calendar monthly and annual basis.

1.2.2 Net Billable Load

Net billable load (NBL) is the sum of energy consumed by, and billed to, customers of FBC. With the implementation of the AMI system, FBC has access to detailed metering data. To calculate NBL for purposes of the 2019 losses study, two broad components were required:

1. A list of all services and meters that were active in the billing system within the study period, and
2. The monthly consumption that occurred at each service and meter combination within the study period.

FBC's Customer Information System (CIS) provided a list of active services and corresponding meters within the study period. Metered consumption data was sourced from AMI related systems or the MV-90 system. The AMI system provided usage data for customers with an AMI

[3] Gross load is adjusted for self-generated power, the portion of system load that belongs to third parties, and wheeling losses incurred on the BC Hydro system that FBC is responsible for.

meter. The MV-90 system is a legacy remote read system that captures and provides consumption data for a small number of large power customers similar to the AMI system. Finally, the CIS billing system is the source of usage estimates for unmetered services with fixed billed consumption such as street lighting.

For each service with AMI data, the midnight read closest to the beginning of the month subtracted from the midnight read closest to the end of the month determined the usage at the specific service within the particular month. Where applicable, calculated consumption was net of power delivered to FBC (e.g., net metering). Hourly data in the MV-90 system was summed to determined usage within a particular month. The billed quantity associated with fixed billing services was deemed the consumption usage. The NBL is the sum of all consumption of all active services in the reporting period.

1.2.3 Company Use

Company use refers to power consumed in the operation of company facilities throughout the FBC system, including offices, generation plants and substations. A wide variety of equipment is required for the operation and maintenance of these facilities, ranging from controls and communications systems to industrial cranes and pumps. FBC is able to measure consumption at the majority of FBC facilities.

1.2.4 Components of System Losses

1.2.4.1 BC Hydro Wheeling Losses

The Amended and Restated Wheeling Agreement (ARWA) is a long-term agreement that allows FBC to wheel electricity over BC Hydro's system. Pursuant to the ARWA, wheeling losses in any particular hour are calculated as 5 percent of the total hourly energy wheeled by BC Hydro from the Kootenay Interconnection to all points of interconnection. These losses occur on the BC Hydro system and are required to be delivered back to BC Hydro within the same hour seven days later[4].

1.2.4.2 Transmission and Distribution Losses and Unaccounted for Energy

After accounting for BC Hydro deemed losses pursuant to the ARWA, the remainder of the system losses are attributable to transmission and distribution losses and unaccounted-for energy, which includes metering inaccuracies and theft. FBC does not have metering in place to accurately delineate losses between transmission and distribution, and continues to estimate. To accurately delineate between transmission and distribution losses, FBC would need to install additional metering along the system, improve existing metering equipment in stations, enhance related IT systems, and assign resources.

4 FBC is required to schedule to BC Hydro amounts of firm electricity equivalent to the hourly wheeling losses deemed to have occurred, based on a constant 5 percent, in the 168th preceding hour.

1.3 RESULTS

Table A:B3-1 shows FBC gross load and the estimated NBL load calculated using AMI data as described in the preceding sections.

Table A:B3-1: 2016 - 2018 System Losses as Percent of Gross Load (GWh)

			2016	2017	2018	Average
1	Gross Load		3,387	3,594	3,531	3,504
2	Estimated NBL		3,124	3,311	3,243	3,226
3	Company Use		12	13	13	13
4	Estimated System Losses	Line 1 – (Lines 2+3)	251	270	274	265
5	Percent of Gross Load	Line 4 ÷ Line 1	7.4%	7.5%	7.8%	**7.6%**

On average, FBC estimates system losses to be 7.6 percent over the 2016-2018 period after excluding company use[5]. FBC does not believe that the slight increases evident over the 2016-2018 timeframe are indicative of an upward trend. Losses during the end of 2017 and first quarter of 2018 were higher than average resulting from system maintenance that interrupted a significant loop connecting Warfield Terminal Station and Vaseux Lake Station (near Oliver). Therefore, FBC considers that the three-year average of losses is an appropriate basis on which to forecast future losses.

1.4 COMPARISON TO PREVIOUS LOSSES STUDY METHOD

The method described in section 3.2 is consistent with the method used in the 2012 losses study, with the exception of the NBL being calculated using monthly consumption from AMI data opposed to customer bill cycle data, and the exclusion of company use. In addition, a separate estimate on the impact of AMI deployment on system losses was added to the pre-AMI method of loss calculation. These components are described below.

1.4.1.1 Net Billable Load Calculation in the 2012 Losses Study

Prior to the deployment of AMI metering, NBL was estimated using customer billing data from the CIS. The majority of FBC's customers are billed on cycles (either monthly or bimonthly) with billing cycle dates distributed throughout the month. Based on a common two-month residential billing cycle, it is possible for actual customer consumption to have occurred over three separate months. For example, a bill cycle between December 5 and February 5 has consumption in December, January and February. In order to estimate NBL for a given period, whether monthly or annually, it was necessary to first estimate the energy consumed during a calendar month.

In the 2012 losses study, billing data was extracted from the CIS system and pro-rated to estimate consumption that occurred within a calendar month. The total usage (kWh) recorded

[5] Table A:B3-2 in the following section shows losses values including company use as historically reported.

by a particular meter was divided by the number of days between the start date and the end date of the bill cycle to provide an average daily usage. The metered usage was pro-rated into calendar months by multiplying the average daily usage by the number of days in each calendar month the bill cycle overlapped. This method is inherently less precise as a means of determining the month and year in which the billed load occurred.

1.4.1.2 AMI Impact

The implementation of AMI had a positive impact on losses (unaccounted-for energy) by deterring theft of power, mainly from indoor marijuana grow sites. Beginning with the 2016 year, FBC has included in its forecast of system losses an adjustment based on estimates developed in the AMI Project CPCN application and subsequently adjusted pursuant to the BCUC's decision on the AMI Project, Order C-7-13.

1.4.1.3 Comparative Results

The following table demonstrates the similarities between the loss calculations using (A) the 2019 Losses Study, (B) as reported for accounting purposes, and (C) the BCUC approved values, including the AMI impact, for 2016 – 2018. For the purpose of this comparison, the 2019 Losses Study results are stated with company use included as a component of system losses to be consistent the historical format.

Table A:B3-2: 2016 - 2018 System Losses + Company Use as Percent of Gross Load (GWh)

			2016	2017	2018	Average
1	A. 2019 Losses Study Method					
2	Gross Load		3,387	3,594	3,531	3,504
3	Estimated NBL		3,124	3,311	3,243	3,226
4	Estimated System Losses plus Company Use	Line 2 – Line 3	264	283	288	278
5	Percent of Gross load	Line 4 ÷ Line 2	7.8%	7.9%	8.1%	7.9%
6	B. As Reported					
7	Gross Load		3,387	3,594	3,531	3,504
8	Reported Actual NBL		3,120	3,305	3,250	3,225
9	Estimated System Losses plus Company Use	Line 7 – Line 8	268	289	281	279
10	Percent of Gross Load	Line 9 ÷ Line 7	7.9%	8.0%	8.0%	8.0%
11	C. Approved					
12	Forecast Gross Load		3,540	3,559	3,485	3,528
13	Forecast Net Load		3,262	3,282	3,213	3,252

			2016	2017	2018	Average
14	Estimated System Losses plus Company Use	Line 12 – Line 13	278	278	272	276
15	Percent of Gross Load	Line 14 ÷ Line 12	7.8%	7.8%	7.8%	7.8%

This comparison shows that (B) reported losses, as estimated using CIS billing data (the 2012 losses study method) are consistent with the (C) forecast losses as approved (also based on the 2012 losses study method) as well as (A) estimated losses using the 2019 Losses Study method based primarily on monthly calculations using AMI metering data. The 2019 Losses Study generally supports the previous method of forecasting annual system losses.

1.5 *LIMITATIONS OF THE 2019 LOSSES STUDY*

The limitations of the 2019 Losses Study are primarily related to the existence of some residual gaps in data required to support monthly consumption calculations. A number of factors, including legacy meters, AMI meters for which customers have chosen the radio-off option, non-communicating AMI meters, and the nature of some data extracts, affected data availability for purposes of the 2019 Losses study.

For non-communicating AMI meters, or in cases where register read data (at the start and end of the month) was not available, a sum of AMI interval data was used, where possible[6]. Small gaps in AMI data were filled using an averaging approach. The averaging approach used available AMI data within each specific month to determine a daily average specific to the particular service, then multiplying the calculated daily average by the number of missing days within that month. In cases where metering data was incomplete to determine consumption for a particular meter on a monthly basis, the historic bill segment pro-rating allocation method used in the 2012 losses study was used to estimate the consumption for the particular meter.

Over the 3-year study period, an average of 93 percent of all consumption on a monthly basis was calculated from verified read data within the losses study. Included in the 7 percent remaining consumption was fixed billed consumption, small gaps filled using AMI daily averages, and, in specific cases where insufficient validated data prohibited monthly consumption calculations, prorated CIS bill segment data was used to estimate consumption for the particular service point[7].

[6] The AMI system collects two different types of read data, namely register data and interval data. Register data is a forward incrementing odometer style read. In contrast, interval data is consumption that occurred over an interval length, such as 60 minutes. The sum of all intervals in a month (e.g., 744 hours in January) is equal to the difference between the register read at the start of the month and the register read at the end of the month, assuming perfect data, no meter exchange, and no change in meter multiplier.

[7] As not all 2018 billing cycles were complete at the time of developing the 2019 study, in the rare event that no verified AMI or MV-90 metering data was available for 2018, the 2017 CIS pro-rated billed value was used.

The bottom up approach employed in the 2019 Losses Study requires the amalgamation of several different data sources which is currently a manual and time-consuming process. This manual management of large volumes of meter level data is not practical on a regular basis.

1.6 *CONCLUSION AND RECOMMENDATIONS*

The 2019 Losses Study determined consumption using AMI as the primary source of data to form a bottom up, direct estimate of NBL for the years 2016 through 2018. The results of the 2019 Losses Study confirm that the existing losses estimate of 8.0 percent is reasonable based on the existing definition of system losses.

FBC recommends that the definition of system losses be revised to remove measured Company Use, a losses value of 7.6 percent of gross load be used for forecast purposes for the 2020-2024 term of the MRP, and that measured company use be treated independently. FBC further recommends the losses study be next updated at the end of the MRP term.

Appendix B4

FEI REVIEW OF CMAE BUDGET

FEI REVIEW OF CMAE BUDGET

1.1 *INTRODUCTION*

The BCUC Decision on the Core Market Adminstration Expense (CMAE) 2014 Budget and Order G-79-14, both dated June 18, 2014, directed FortisBC Energy Inc. (FEI) to submit its CMAE Budget within its next revenue requirements application (i.e., after the Current PBR Plan period), stating:

> The Panel acknowledges FEI's request to submit the CMAE budgets with the fourth quarter gas cost reports. However, the Panel is concerned that if the CMAE Budget is submitted at the same time, the Commission would have insufficient time to properly review the CMAE Budget. **Further, the Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications. Therefore, until such time as FEI files its next revenue requirements application, the Panel directs FEI to submit future CMAE budgets separately to the Commission at least two weeks prior to the fourth quarter gas cost report to allow the Commission sufficient time to review the CMAE Budget, and to determine if there are sufficient variances from the previous CMAE Budget to warrant a more fulsome review.**
>
> **The Panel directs that the CMAE Budget review and approval process be included within the FEI revenue requirements application starting with the next such application filed by FEI.**
>
> While the Panel acknowledges FEI's position that CMAE is an essential component of the cost of gas, the Panel believes there is benefit to reviewing the CMAE Budget with other similar costs within the larger FEI budget.

Further to the BCUC's directives above, during the term of the Current PBR Plan, FEI has been submitting its CMAE budgets at least two weeks prior to the fourth quarter gas cost report. For example, FEI filed its 2019 CMAE Budget Application for BCUC review and approval on November 7, 2018, which was two weeks before the Fourth Quarter Gas Cost Reports, which were filed on November 23, 2018.

For the term of the proposed MRP, FEI will file its request for approval of its CMAE budget for the upcoming year as part of its annual review filings. In the annual review filings, FEI will provide the information to support the CMAE request as a separate item within the Cost of Gas section, which in the past has not had any approval requests associated with it (since all approvals have been through other processes during the term of the Current PBR Plan).

FEI notes that it is often necessary to request approval of interim delivery rates through the annual review process, since decisions on permanent delivery rates can be received subsequent to January 1 of the following year[1]. Since, in this situation, both permanent commodity and permanent midstream rates will have been approved through a separate process, FEI understands that the direction to include approval of CMAE through the annual review process will result in any variances between the amounts forecast through the annual review process and the final amounts approved being recorded in either the CCRA or MCRA account, as applicable. This is consistent with the current treatment of any variances between approved and actual CMAE costs.

To provide context to the 2019 CMAE budget, the following is an overview and general discussion of the FEI Gas Supply and the CMAE budget.

1.2 *OVERVIEW OF GAS SUPPLY DEPARTMENT*

FEI's Gas Supply department is funded from two main sources – the CMAE budget and an O&M budget. CMAE costs are a direct result of the activities performed to serve core market customers and are recovered separate from the delivery costs which are set through revenue requirement filings, via gas cost recovery rates. In contrast, the on-system transportation activities performed by the Gas Supply group support the transportation services business model, and these costs are included in O&M costs. Other activities of the department, including management oversight, are required to support all customers, and are also included in O&M costs.

1.3 *CMAE BUDGET*

CMAE captures the costs that FEI incurs in planning, managing, and optimizing the gas portfolios, mitigating unrequired resources, managing the credit exposure to counterparties, and minimizing the impact of unfavourable upstream regulatory developments.

The gross cost of the gas supply portfolio is currently in excess of $500 million and represents the largest single component of FEI's revenue requirement. This cost can change dramatically with an increase in commodity costs or in transportation and storage costs.

The CMAE component of the gas supply portfolio is required for the FEI staff and resources that are necessary:

- to plan and optimize gas supply requirements and set them out in the Annual Contracting Plans,
- to manage the gas supply resources on a daily basis and mitigate any unneeded resources,

[1] Due to the anticipated timing of a decision on this Application, FEI will be filing for interim delivery rates in the fourth quarter of 2020, separate from the annual review process which will occur after the decision. For 2020, FEI will need to continue to request approval of the CMAE through the process that is currently in place; that is, filing for approval two weeks prior to the filing of the Fourth Quarter Gas Cost Report.

- to establish appropriate contracts with counterparties and manage their credit exposure,
- to manage upstream regulatory developments so that unfavourable developments are minimized and opportunities identified that can provide benefits, and
- to complete the support activities related to regulatory and financial reporting and compliance.

The CMAE is a critical component of an integrated gas supply function because it enables FEI to carry out these responsibilities.

The level of the CMAE budget is determined by the scope of work required to meet the responsibilities described above, which may increase or decrease year over year. For example, the CMAE budget may increase in a year when significant upstream regulatory developments require intervention in proceedings to ensure the interests of customers are protected. Successful mitigation activities such as these, for which specialized expertise is needed, can also result in several millions of dollars in incremental revenue that offsets the overall cost of gas for the benefit of customers.

An important part of developing this optimal portfolio is the evaluation of resources available to meet both normal and peak day core load requirements. This includes support activities such as portfolio modelling and resource assessment, regional supply and demand analysis, discussions and meetings with pipeline and storage operators, maintaining strong relationships with gas producers and marketers, negotiation and administration of commodity, pipeline and storage contracts, and staying on top of new regional infrastructure developments and seeking opportunities for contracting resources related to cost effective pipeline or storage capacity expansions or additions.

Providing safe, reliable, and cost effective gas supply resources that are required to meet core customers' load demands is the central purpose of CMAE activities. These CMAE activities are provided on the basis of a single administrative function and the costs are allocated between the gas supply commodity and midstream portfolios; the costs are allocated 30 percent to the Commodity Cost Reconciliation Account (CCRA) and 70 percent to the Midstream Cost Reconciliation Account (MCRA) based on the activities performed by employees in the Gas Supply area.

Appendix B5

FEI AND FBC REPORT ON EVACUATION RATE RELIEF

EVACUATION RATE RELIEF

On August 1, 2018, FEI and FBC filed applications for approval to provide to customers who were under an evacuation order due to flooding or wildfires between May 1 and August 31, 2018, a credit for the charges that would otherwise have applied to FEI Rate Schedules 1, 1U, 1X, 1B, 2, 2U, 2X, 3, 3U, 3X, 3B and 23; and to FBC Rate Schedules 1, 2A, 3, 3A, 20, 21, 22A, 23A, 60, 61 and 95. The Companies also requested approval for tariff changes to permit evacuation relief for customers who are subject to an evacuation order. On September 13, 2018, by way of Orders G-169-18 and G-170-18, the BCUC approved for FEI and FBC, respectively, to provide a credit for the Applicable Charges to the end of the 2018 calendar year. The BCUC deferred the review of the requests for tariff changes to a later date.

1.1 *REVIEW OF EVACUATION BILL RELIEF ON 2018 REVENUES AND COSTS*

Directive 3 of both Orders G-169-18 and G-170-18 directed the Companies to report on the impact of the evacuation bill relief on the 2018 revenues and costs in its next Annual Review of Delivery Rates application. Since the next annual review, which will be for 2020 rates, will not occur until after the conclusion of this proceeding, FEI and FBC are providing the requested information in this Application.

The following table summarizes the costs associated with the 2018 evacuation relief provided by FEI and FBC.

Table A:B5-1: Costs Associated with 2018 Evacuation Relief

Year	Business	Event	Accounts Impacted	Bill Credit Amount	Estimated Admin Costs
2018	FEI	Flooding	721	$ 2,597.37	$ 10,750.00
2018	FEI	Wildfire	5	$ 615.41	$ 19,650.00
2018	FBC	Flooding	1,873	$ 58,656.51	$ 19,720.00
2018	FBC	Wildfire	24	$ 1,072.46	$ 5,200.00

The Companies note that related administrative costs are not accounted for separately, are part of customer service O&M as opposed to an additional cost, and are estimated based on an allocation of transaction time.

Appendix B6

FEI REPORT ON MAJOR INITIATIVES DURING THE PBR TERM

FEI REPORT ON INITIATIVES DURING THE PBR TERM

As directed by the BCUC, FEI provides below a table for each of the major productivity initiatives that FEI has implemented as discussed in Section C2 in the format requested by the BCUC.

Table A:B6-1: Regionalization Initiative – Phase 1

	2014	2015+
Activities undertaken	• Operations Supervisor recruitment and training • Dispatcher relocation, recruitment and training • Planner relocations • Process review and modification • IT infrastructure and system modifications • Facilities modifications	None
Organizational changes	• Dispatch staff decreases • Operations staff increases due to hiring of Operations Supervisors • Operations staff decreases due to retirements and terminations not replaced • Planners staff re-allocated to Operations	None
O&M expenditures incurred or expected to be incurred	**$0.9 million** This included costs for a number of activities including employee development/ training, IT and facilities.	None
Capital expenditures incurred or expected to be incurred	**$1.3 million** This includes costs for IT, facilities and communications.	None
Anticipated savings	**$1.0 million** approximately. As discussed in the response to BCUC IR 1.2.1 in the annual review for 2015 delivery rates, it is difficult to separate Regionalization savings from the savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.	Ongoing

Table A:B6-2: Regionalization Initiative – Phase 2

	2016	2017+
Activities undertaken	• Regionalize pre-req, closing, and hazards functions closer to service areas • Process review and modification • IT infrastructure modifications • Facilities modifications	None
Organizational changes	• Operations support staff decreases • Operations support staff re-allocated to service areas	None
O&M expenditures incurred or expected to be incurred	**$0.8 million** This included costs for a number of activities including employee development/training, IT, facilities and communication	None
Capital expenditures incurred or expected to be incurred	**$0.7 million** This includes costs for IT and facilities and back office costs.	None
Anticipated savings - Labour	**$1.1 million** approximately. Similar to Phase 1, it is difficult to separate Regionalization savings from the savings achieved due to the broader initiatives of improving customer service, enhancing the productivity focus and strengthening the accountability culture.	Ongoing

Table A:B6-3: Project Blue Pencil

	2014	2015	2016+
Processes Reviewed	High Bill Inquiry Emergency Collections Meter Exchange New Construction		
Organizational Changes	Contact center and billing operations will experience a FTE reduction as a result.	Contact center and billing operations will experience a FTE reduction as a result.	Contact center and billing operations will experience a FTE reduction as a result.
O&M expenditures expected to be incurred	$0 Incremental O&M costs	$0 Incremental O&M costs	$0 Incremental O&M costs
Capital expenditures expected to be incurred	<$100 thousand	<$200 thousand	$0
Annual Savings - Labour	< $100 thousand	Approximately $1 million annual contact centre and billing operations O&M savings.	Approximately $1 million annual contact center and billing operations O&M savings.
Annual Savings – non-Labour	$0	$0	$0

Table A:B6-4: Review of Technical and Infrastructure Support Provider

	2014	2015	2016+
Services Contract update and change	This is an initiative to review the existing agreement with the Company's technical and infrastructure service provider. This includes the employee help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. This includes the employee Help desk and operation of the end-user environment, data centre infrastructure, communication and security networks. The new contract with Compugen is designed to better support the Company's requirements and to drive efficiency. For each permanent reduction in Compugen's costs to support FEI, the vendor and FEI share in the savings that are achieved, providing an incentive for Compugen to work with FEI to continue to look for efficiencies. Additionally, the new contract provides dedicated support resources rather than a distributed support service resulting in quicker response times and better understanding of the Company's requirements.		
Organizational Changes	Contract awarded to Compugen after RFP process. Transitioned from incumbent third party provider, Telus, to successful bid proponent Compugen.	Compugen takes over support contract.	
Capital expenditures incurred	$1.1 million to replace the Service Request system that required replacement to complete the transition.	$400K to complete the project to replace the Service Request system.	$0
Annual Savings – non-Labour	$0	$1.8 million	$2 million

Table A:B6-5: Online Service Application

	2015 / 2016	2017+
Activities undertaken	• Development of internet based application using .net technology. • Interfaces with existing enterprise applications such as SAP, GIS, ClickSchedule, Café using Web Services and BizTalk.	None
Organizational changes	• None	None
O&M expenditures incurred or expected to be incurred	**$0.05 million** This included costs for analysis, training and change management.	$0.01 million
Capital expenditures incurred or expected to be incurred	**$1.8 million** This includes the costs for developing the application.	$0.5 million
Anticipated savings	This application is designed to enhance the customer experience by offering customers another channel to request a service line in addition to the existing customer contact centre voice channel.	$0.05 million annual O&M savings

Table A:B6-6: SAP Integration

	2017 and 2018	2019+

Activities undertaken	• Blueprint / Technical Design Phase
	• Realization Phase
	• Testing
	  o Regression Test
	  o Data Migration Test
	  o Integration Test
	  o Security Test
	  o User Acceptance Test
	• Cutover Phase & Go Live
	• Stabilization Phase
		None

Organizational changes	• Displacement of contractors with internal resources	None
O&M expenditures incurred or expected to be incurred	$0.3 million This included costs for Change Management support.	None
Capital expenditures incurred or expected to be incurred	$4.2 million This includes costs for implementation including build, test and deliver.	None
Anticipated savings	None in 2017 and 2018. The project was completed in 2018 with savings expected in 2019 and onwards.	$0.9 million ($0.6 m FEI; $0.3 m FBC)

Table A:B6-7: Gas Workforce Management

	2017 - 2019	2020+
Activities undertaken	• Streamline and improve field work processes • Requirements and Design Workshops (3 rounds) • Change Management • Software Build • Software Test • User Acceptance Testing • Training • Go-live (late 2019) • Go-Live and post implementation support	Post implementation support
Organizational changes	• None	None
O&M expenditures incurred or expected to be incurred	$0.7 million This included costs for Change Management support.	None
Capital expenditures incurred or expected to be incurred	$5.8 million This includes costs for implementation including build, test and deliver.	None
Anticipated savings	Project completion is expected in late 2019. It will deliver improved safety, and customer experience, as well as simplify the user experience and reduce O&M.	$0.5 million annual O&M savings

Table A:B6-8: Common Trenching

	2018 and 2019	2020+
Activities undertaken	In collaboration with other shallow utility owners, developers, and customers, FEI is currently developing a program to install gas mains and multi-family services in conjunction with other underground infrastructure such as electric, telephone, and cable conduit. By installing gas infrastructure early and concurrently, FEI is able to increase onsite safety and improve customer service by decreasing construction time for customers and reducing development costs. Customers can get gas pipe installed earlier and FEI can reduce installation effort by avoiding conflicts with other utilities and surface infrastructure. Additionally, FEI expects the program may result in a reduction of installation costs over time. At this time, FEI is not able to estimate the level of savings that may be achieved. To date, FEI has completed four party trenching projects in the Fraser Valley, Okanagan and Vancouver Island. The projects have generated learnings and satisfied customers, as well as provided FEI with opportunities to determine best practices and improve the process.	
Organizational changes	• None	None

	2018 and 2019	2020+
O&M expenditures incurred or expected to be incurred	• Negligible	None
Anticipated savings	Program is currently under development with savings to be determined	Savings to be determined

Appendix B7

FEI REPORT ON HEADCOUNT AND FTE

FEI REPORT ON HEADCOUNT AND FTE

As directed by the BCUC in Order G-237-18, FEI provides the following Table A:B7-1 with the headcount information and Table A:B7-2 with the FTE information by the various categories requested.

Table A:B7-1: Headcount

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Projected	2017 Actual	2017 Projected	2018 Actual	2018 Projected	2019 Projected
Total Annual Headcount	1,764	1,704	1,656	1,667	1,721	1,735	1,724	1,805	1,816	1,827
Change in Annual Headcount (year over year)	(1)	(60)	(48)	11	65	68	57	70	81	22
# of Positions Added Each Year (total) and broken down as follows:										
Regionalization Initiative - Phase 1 and 2	-	31	-	-	-	-	-		-	-
Project Blue Pencil	-	-	-	-	-	-	-		-	-
Other Major Initiatives	-	-	-	-	-	-	-		-	-
Outside of Base O&M	25	(4)	(5)	6	19	25	28	55	58	5
Inside Base O&M	(26)	(34)	(32)	23	46	43	28	15	23	17
Total Positions Added	(1)	(8)	(37)	30	65	68	57	70	81	22
# of Positions Eliminated Each Year (total) and broken down as follows:										
Regionalization Initiative - Phase 1 and 2	-	(52)	-	(19)	-	-	-	-	-	-
Project Blue Pencil	-	-	(10)	-	-	-	-	-	-	-
Other Major Initiatives	-	-	-	-	-	-	-	-	-	-
Outside of Base O&M	-	-	-	-	-	-	-	-	-	-
Inside Base O&M	-	-	-	-	-	-	-	-	-	-
Total Positions Eliminated	-	(52)	(10)	(19)	-	-	-	-	-	-
Net Change in Headcount (year over year)	(1)	(60)	(47)	11	65	68	57	70	81	22
# of Unfilled Vacancies										
# of Unfilled Vacancies for each year	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Table A:B7-2: FTE

	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2016 Projected	2017 Actual	2017 Projected	2018 Actual	2018 Projected	2019 Projected
Total Annual FTEs	1,679	1,650	1,573	1,581	1,613	1,648	1,650	1,727	1,727	1,742
Change in Annual FTEs (year over year)	(3)	(29)	(77)	8	40	67	69	79	79	15
# of Positions Added Each Year (total) and broken down as follows:										
Regionalization Initiative - Phase 1 and 2		31								
Project Blue Pencil										
Other Major Initiatives										
Outside of Base O&M	25	(4)	(5)	6	10	25	28	55	58	5
Inside Base O&M	(28)	(3)	(62)	21	30	42	40	24	21	10
Total Positions Added	(3)	23	(67)	27	40	67	69	79	79	15
# of Positions Eliminated Each Year (total) and broken down as follows:										
Regionalization Initiative - Phase 1 and 2		(52)		(19)						
Project Blue Pencil			(10)							
Other Major Initiatives										
Outside of Base O&M	-	-	-	-	-	-	-		-	-
Inside Base O&M										
Total Positions Eliminated	-	(52)	(10)	(19)	-	-	-	-	-	-
Net Change in FTE - year over year	(3)	(29)	(77)	8	40	67	69	79	79	15
# of Unfilled Vacancies - included related to O&M, Capital, Other										
# of Unfilled Vacancies for each year	19	30	39	51	n/a	50	n/a	42	n/a	n/a

At this time, the 2019 projected average FTE and end of year headcount are expected to be slightly higher than 2018 actuals as vacancies are filled and hires during the latter part of 2018 are fully reflected in 2019. The 2019 projected average FTE and headcount is consistent with the overall staffing level observed in January 2019.

Overview of Approach to Preparing the Information Requested

The numbers provided in the tables above are FEI's approximation of the changes in headcount and FTE by the different classifications (Regionalization Initiative, Project Blue Pencil, Other Major Initiatives, Outside Base O&M, Inside Base O&M, etc.) as outlined in the format provided by the BCUC in Appendix A to Order G-182-16.

FEI does not track and report headcount and FTEs in the classifications outlined by the Commission. FEI's Human Resources systems track employees and the positions that they occupy and which part of the organization they belong to. In addition, the systems track changes in the status of positions, occupied positions added and removed. The position changes tracked in the systems include the transfers of employees from one department to another, even though the changes do not necessarily represent true net changes to the organizational overall.

Reporting on the classifications requested by headcount and FTEs is inherently difficult. An employee, depending upon their job responsibilities, may perform a number of activities that fall into the different classifications outlined. For example, an employee may spend 80 percent of their time performing O&M activities with the remaining 20 percent of their time on capital activities. On an FTE basis, 0.80 FTE would be reported as O&M and 0.20 FTE reported as Capital. However, a headcount cannot be split, so the headcount can be reported as either O&M or Capital, but not partly O&M and partly Capital. As a result, the headcount information provided in Table A:B7-1 above has been completed in a similar manner to that reported on a 1 FTE basis in Table A:B7-2 (i.e., one FTE equals one headcount). Where there are differences between the headcount and FTE information (which are typically caused by vacancies within a given period and the use of part-time and temporary employees), for the purpose of the information requested, the differences are reported as part of the Inside Base O&M classification, recognizing that the Inside Base O&M classification accounts for the majority of headcount and FTE at FEI.

With the limitations described, FEI's approach to generating the information requested by the BCUC was to first approximate the changes in FTEs by the broad classifications (i.e., Inside Base O&M, Outside Base O&M). This was estimated using financial and costing data in FEI's SAP system. The financial data was then converted to FTEs using average annual wage/salary assumptions for different employee affiliations (i.e., M&E, IBEW, MoveUp). Reporting by specific initiatives (i.e., Regionalization, Project Blue Pencil) was based on additional headcount and FTE information available, as the headcount and FTE changes were tracked separately for some initiatives. Adjustments to the FTEs reported for the broad classifications (i.e., Inside Base O&M, Outside Base O&M) were made to avoid double-counting of the changes.

Separating the FTE changes into Additions and Deletions is not possible given the existing systems and information available. Changes in FTEs can occur for different reasons, including new positions, positions eliminated, turnover of staff (i.e., vacancies) and changes in the how much time is allocated between one activity versus another (O&M versus Capital). As a result, FEI was only able to separate Additions from Deletions for the Regionalization and Blue Pencil initiatives, as these were the only ones where the information was tracked separately. Therefore, other than for these two initiatives, the information requested is reported on a Net Change basis.

With regards to the "# Unfilled Vacancies" information requested, FEI understands "Unfilled Vacancies" to mean existing positons that become temporarily vacant due to turnover. For FEI, the proxy to measure this is by taking the number of job bulletins identified as for "replacement" in a given year and calculating how long the job bulletins are vacant for. The days vacant estimated are then converted to an FTE basis. However, FEI is unable to determine specifically for all the job vacancies in a given year, how many are related to the different classifications (i.e., O&M, Capital), or whether in the interim the vacancy was filled by use of a contractor or a consultant, or by additional overtime (unpaid or paid) by existing employees. Due to the difficulties described, FEI has not forecast Unfilled Vacancies (i.e., 2019 Projected).

Given the above circumstances and assumptions, the headcount and FTE information provided are approximations only. The information is indicative of factors contributing to headcount and FTE changes, instead of having a direct and accurate correlation to costs incurred and savings realized.

Appendix B8

CAPITAL DIRECTIVES

Appendix B8-1

FEI CAPITAL DIRECTIVES

FEI CAPITAL DIRECTIVES

1. INTRODUCTION

In Order G-182-16 in FEI's Annual Review for 2017 Rates, at page 17, the BCUC set out the following capital directives.

> The Panel directs FEI to provide the following information in its annual review for 2018 delivery rates application:
>
> - The information contained in Table 1-3 of the Application updated for 2016 Actuals and Projected 2017 results;
> - A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Growth Capital, which separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any);
> - A breakdown and explanation for both the annual variances (i.e. 2014, 2015, 2016 and 2017), and the cumulative variance between formula and actual/projected Sustainment/Other Capital, which separately quantifies the amount of the annual variances and cumulative variance attributable to: (i) the reduction to the Base Sustainment Capital for the Vancouver Island region; (ii) the growth factor for net customer additions; (iii) the Regionalization Initiative; (iv) the installation of Jomar valves; (v) increased in-line inspection activity; (vi) unanticipated system improvements and new stations to supply gas to large new customers; (vii) Burns Bog Stress Relief; and (viii) other contributing factors (if any); and
> - A description of how FEI is prioritizing its capital expenditures during the remainder of the PBR term, with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken during the PBR term. FEI must also provide a description of any projects which it had originally planned to complete during the PBR term but are now expected to be delayed until after the PBR term.

In Order G-196-17 in FEI's Annual Review for 2018 Rates, at page 10, the BCUC provided the following directive.

> The Panel directs FEI to continue to report on capital spending in the manner outlined in the FEI Annual Review for 2017 Delivery Rates Reasons for Decision, attached as Appendix A to Order G-182-16, for the remainder of the PBR Plan

> term.[1] These capital reporting requirements must include updating the information in Table 1-4 provided in the Application as well as updating the information in Appendix C4 to the Application.

Further, in Order G-237-18 in FEI's Annual Review for 2019 Rates, the BCUC stated at page 14:

> In consideration of the above, the Panel directs FEI to file the information contained in Appendices C2, C3 and C4 of the Application, as well as Table 1-4 of the Application, as part of FEI's upcoming revenue requirement application.

Table B2-4 (Growth Capital) and B2-5 (Sustainment and Other Capital) in Section B2 of the MRP Application show the annual and cumulative variances between actual/projected and formula capital expenditures. In this Appendix, FEI provides the requested information for each of the remaining areas described in Order G-182-16.

2. ANNUAL GROWTH CAPITAL VARIANCES

This section provides annual and cumulative variances between formula and actual/projected growth capital broken down into mains growth capital and service line additions growth capital. In its Directive, the BCUC requested information which includes a breakdown and explanation for both the annual variances and the cumulative variance between formula and actual/projected growth capital, and separately quantifies the amount of the annual variance and cumulative variance attributable to (i) the growth factor for service line additions; (ii) the addition of larger industrial mains; and (iii) other contributing factors (if any). As shown in Table B2-4 of the Application, the cumulative growth capital variance for the 2014 to 2018 period is $105.8 million. The service line additions growth capital variance discussed in Section 2.1 below totals $78.7 million, and the mains growth capital variance discussed in Section 2.2 below totals $25.8 million. These two amounts sum to $104.5 million of the $105.8 million cumulative growth capital variance.

The growth capital variances are attributable to two main factors: (1) an increase in the volume of service and main installations, and (2) a higher per installation cost than was utilized in calculating the approved formula growth capital amounts. FEI's Base Capital costs for the 2014-2019 PBR (Current PBR) period were based on the 2013 Approved (for FEI) and 2014 Approved (for Vancouver Island and Whistler) growth capital costs, which were in turn based on 2010 actual costs for FEI and 2012 actual costs for Vancouver Island and Whistler. Since that time, FEI has seen a substantial increase in the number of services and mains installed to meet customer demand, and an increase in installation costs. As a result, overall growth capital expenditures are higher than what the Current PBR Plan formula allows.

[1] FEI Annual Review for 2017 Delivery Rates, Order G-182-16 and Reasons for Decision, dated December 7, 2017, Appendix A, p. 17.

It is important to note that, for growth capital, each customer must pass an extension test in order to attach to the system. This test is either a service line cost allowance test or a main extension test. If the customer passes this test, or elects to pay a contribution if they do not pass the test, FEI is obligated to provide service to the customer[2]. These tests do not consider restrictions on capital spending, whether through a PBR formula or otherwise. Further, in the case of particularly large mains, costs may be high, but offsetting revenues may be high as well. Thus, higher capital expenditures may be offset by higher revenue. As noted in the regulatory proceeding to review FEI's system extension policies, the addition of customers from 2008-2014 has had a positive effect on rates, since new customers pay more than their cost to serve.

Variances attributed to service line addition growth capital and mains growth capital are further explained below.

2.1 *SERVICE LINE ADDITIONS GROWTH CAPITAL VARIANCE*

To determine the annual and cumulative variance from service lines additions FEI first had to determine the approved capital amount for service line additions embedded in growth capital. The following table shows the break out of approved growth capital split by Mains, Meters and Service Line Additions (SLAs). As shown in Table A:B8-1-1, the cumulative approved formulaic capital for SLAs is $94.6 million.

Table A:B8-1-1: Components of Approved Growth Capital ($000s)

Line No.	Year	Approved Growth Capital	Growth Capital for Mains	Growth Capital for Meters	Growth Capital for SLAs
1	2014 A	$ 21,479	$ 6,490	$ 2,102	$ 12,886
2	2015 A	28,480	8,672	2,312	17,495
3	2016 A	33,262	10,129	2,700	20,432
4	2017 A	33,477	10,194	2,718	20,565
5	2018 A	37,485	11,284	3,008	23,192
6	**Cumulative**	**$ 154,182**	**$ 46,770**	**$ 12,841**	**$ 94,572**

The following Table A:B8-1-2 shows the total capital variance and then splits the total variance into activity and cost components.

[2] Section 28 (1) of the *Utilities Commission Act*: "*On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose*."

Table A:B8-1-2: Service Line Addition Capital Variances ($000s unless otherwise noted)

		Approved			*Actual*			*Variance*	
Line No.	**Year**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**$/SLA**	**Capital**	**SLAs**	**Capital**
1	2014 A	7,934	$ 1,624	$ 12,886	8,473	$ 2,096	$ 17,762	539	$ 4,876
2	2015 A	9,586	$ 1,825	$ 17,495	12,392	$ 2,430	$ 30,110	2,806	$ 12,615
3	2016 A	11,143	$ 1,834	$ 20,432	12,288	$ 2,546	$ 31,291	1,145	$ 10,859
4	2017 A	11,180	$ 1,840	$ 20,565	15,856	$ 2,497	$ 39,594	4,676	$ 19,029
5	2018 A	12,443	$ 1,864	$ 23,192	16,606	$ 3,283	$ 54,511	4,163	$ 31,318
6	**Cumulative**	**52,286**	**$ 1,809**	**$ 94,572**	**65,615**	**$ 2,641**	**$ 173,269**	**13,329**	**$ 78,696**
7									

		Activity Variance (Approved)			*Cost Variance*			*Variance*
8								
9	**Year**	**SLAs Variance**	**Approved $/SLA**	**Capital Variance from # SLAs**	**Actual SLAs**	**$/SLA Variance**	**Capital Variance from Cost per SLA**	**Capital**
10	2014 A	539	$ 1,624	$ 875	8,473	$ 472	$ 4,001	$ 4,876
11	2015 A	2,806	$ 1,825	$ 5,122	12,392	$ 605	$ 7,493	$ 12,615
12	2016 A	1,145	$ 1,834	$ 2,099	12,288	$ 713	$ 8,760	$ 10,859
13	2017 A	4,676	$ 1,840	$ 8,603	15,856	$ 658	$ 10,426	$ 19,029
14	2018 A	4,163	$ 1,864	$ 7,759	16,606	$ 1,419	$ 23,559	$ 31,318
15	**Cumulative**	**13,329**		**$ 24,458**	**65,615**		**$ 54,239**	**$ 78,696**

2.1.1 Growth Factor for Service Line Additions

The variance in approved versus actual, for both SLAs and overall capital, is impacted by the Current PBR formula which uses a historical growth factor to determine the future years approved capital expenditures, in addition to the growth formula accounting for only one half of growth[3]. As a result, the Current PBR Plan formula does not accurately account for the actual number of service line additions. Line 15 from Table A:B8-1-2 shows that FEI has installed 13,329[4] more service lines than the formula contemplated, which accounts for $24.5 million of the total variance.

2.1.2 Other Factors Contributing to the Variance for Service Line Additions

As shown in line 15 of Table A:B8-1-2, overall service line attachments were higher than the formula allowed. Line 6 also shows that the actual average cost per SLA is $832 per SLA higher than the formula approved amount ($2,641 - $1,809). Consistent with the factors discussed in Appendix C4 Capital Directives of the FEI Annual Review for 2019 Rates, the primary factors that have changed since the base capital per SLA amounts were developed, and that are contributing to the cost per service line variance include:

[3] FEI has calculated the impact on Total Capital of the growth factors for SLAs and net customer additions being reduced by half in Section 1.4.4.1 of the FEI Annual Review for 2019 Rates Application. In addition, FEI is compensated for the use of an historical growth level instead of actual through the earnings sharing mechanism, but the capital formula itself is not adjusted for the lag. The adjustment to the earnings sharing mechanism is described in Section 10.1.2 of the FEI Annual Review for 2019 Rates Application.

[4] 2014 – 2017 Actual plus 2018 Projection

- An increase in customer attachments per service line, which results in a higher cost per service line addition;
- An increase in SLA activity on Vancouver Island (where costs are higher), compared to the SLA activity in the growth capital formula;
- An unfavourable USD exchange rate that has resulted in an increased cost of equipment and supplies purchased from the United States; and
- Local government requirements.

These contributing factors are described in more detail below.

2.1.2.1 Increase in Customer Attachments per Service Line Addition

Due to the changing housing market from single detached homes to multi-family developments, FEI is seeing an increase in the number of customer attachments per SLA. In the case of a single detached home, there is generally one customer attachment per SLA. In the case of a multi-family development, there can be upwards of 10 to 40 customers attaching to a single service line. For example, in 2012 there were approximately 1.2 customers per SLA, whereas in 2016 there were approximately 1.4 customers per SLA. The average customer attachment per SLA ratio for the past three year period (2015-2018) has been approximately 1.35. To serve a single detached home requires smaller pipe, fewer fittings, and a smaller riser resulting in a lower cost per service line attachment compared to the cost to serve a multi-family development, which requires a service line attachment with larger pipe, additional fittings and a larger riser contributing to a higher SLA cost.

2.1.2.2 SLA Activity on Vancouver Island and the Cost per Service Line Addition

The cost variance is due in part to the increase in SLA activity on Vancouver Island compared to the SLA activity in the growth capital formula. When the Vancouver Island and Whistler service areas were amalgamated with FEI, the 2014 growth capital base was adjusted for both the number of SLAs and the cost per SLA for Vancouver Island (and Whistler). At that time, the Vancouver Island SLA adjustment added 2,167 SLAs, which represented 21 percent of the total 2014 SLAs of 10,156. In 2015, 2016, 2017 and 2018, FEI is experiencing increased SLAs on Vancouver Island compared to those in the base (26 percent, 29 percent, 28 percent and 35 percent of total SLAs in 2015, 2016, 2017 and 2018, respectively). The increase in this activity on Vancouver Island at a higher cost per SLA than the Mainland is a contributing factor to the cost variances attributed to SLAs.

2.1.2.3 USD Exchange Rates

The Canada-United States exchange rate forecast, on which FEI based its capital cost assumptions for the Current PBR term, was higher than the exchange rates that have been realized during the Current PBR term. FEI's Base Capital for the Current PBR Plan was set at

FEI's 2013 Approved levels, with additions for Vancouver Island and Whistler based on 2014 Approved expenditures, following the amalgamation of the companies. FEI's 2013 Approved capital expenditures were based on a CAD/USD exchange rate forecast of $0.97 and Vancouver Island (and Whistler) Approved capital expenditures in 2014 were based on a CAD/USD exchange rate of $0.99. Thus, FEI's Base Capital was set based on an expectation that the exchange rate would be close to par, whereas capital expenditures during the Current PBR term have been incurred at an exchange rate closer to 0.8[5]. This causes capital cost pressure on FEI's formula-driven expenditures under the Current PBR Plan.

2.1.2.4 Evolving Local Government Requirements

Local governments have implemented regulations that place increased requirements on utilities. FEI is continuing to work with local governments and regulators to meet evolving municipal regulations. Additional permitting requirements, working arrangements and restricted working hours have added additional cost pressures to growth capital.

2.2 *MAINS GROWTH CAPITAL VARIANCE*

As noted in the preamble to the discussion on growth capital, FEI is experiencing strong customer growth in both service lines and in mains with more residential developments which require main extensions, but also a number of larger mains required for commercial/industrial customers.

The annual and cumulative variances between formula and actual capital is provided for total New Customer Mains as shown in Table A:B8-1-3 below. Mains expenditures in 2018 were significantly higher than 2017 resulting from a steep increase in activity in early 2018. In 2018 FEI saw an increase in mains activity of approximately 32 percent, which resulted in over 49,000 meters of additional main installed compared to last year.

Table A:B8-1-3: New Customer Mains ($ thousands)

New Customer Mains (000's)	Actual/ Projected	Allowed	Variance	Var%
2014	5,399	6,649	(1,250)	-19%
2015	14,082	9,007	5,075	56%
2016	13,103	10,444	2,659	25%
2017	16,654	10,400	6,253	60%
2018	24,729	11,657	13,072	112%
Cumulative	73,966	48,156	25,810	54%

5 Average 2014 through 2018 Bank of Canada indicative CAD/USD exchange rate (2014: 0.91, 2015: 0.78, 2016: 0.76, 2017: 0.77 , 2018: 0.78)

The variance in costs for customer mains is driven partly by the growth in large industrial mains, and a number of other factors as outlined in Section 2.2.2 below.

2.2.1 Growth in Larger Industrial Main Additions

FEI does not have a capital formula specific to larger industrial mains so is not able to directly quantify the amount of the variance due to this factor. Instead, FEI provides the following discussion of larger mains.

The average cost per metre of main in FEI's 2013 Base was $62 per metre. The actual cost per metre of main was $87 in 2014, $121 in 2015, $121 in 2016, $110 in 2017 and $123 in 2018. The 2014 through 2018 costs have been influenced upward by a number of larger cost mains. The 34 mains with the highest cost per metre that FEI has installed since 2014 had an average cost per metre of $308, which has contributed approximately $5.8 million to date to the capital cost pressure when compared to the average cost that was embedded in the Current PBR formula.

In 2010, the year that was used to develop the 2013 Base for the Current PBR formula, there was one new main with a cost greater than $100 thousand. This compares to 15 and 11 new mains greater than $100 thousand in 2015 and 2016, respectively. The number of larger new mains (greater than $50 thousand) has more than doubled in 2015 and 2016 compared to that of 2014. In 2017, FEI installed approximately 400 meters of new main for a customer that was more than seven times the average unit cost of $110 per metre of main. Several factors contributed to the higher unit cost for the main installation including complexity of the service renewals, additional costs associated with maintaining road access to the fire hall and additional paving costs requested by the city.

FEI mains expenditures are driven by customer growth and the type of customer impacts the timing, size and cost of the mains. The decision by large industrial customers to connect to FEI's system, their load profile and the location they wish to connect to are largely driven by factors outside the control of FEI. Larger diameter and more costly mains to serve customer load requirements, in addition to a significantly larger number of main installations compared to previous years, have contributed to variances in growth capital.

2.2.2 Other Factors Contributing to the Variance for Mains

Some of the cost pressures contributing to the SLA growth capital variance also contribute to the Mains growth capital variance. An increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate and local government requirements are contributing to the mains growth capital cost variance.

3. ANNUAL SUSTAINMENT/OTHER CAPITAL VARIANCES

In Table A:B8-1-4 below, FEI provides a breakdown and itemization of variances attributable to the items identified by the BCUC.

Table A:B8-1-4: Annual Sustainment/Other Capital Variances ($ millions)

Line No.	Description	2014	2015	2016	2017	2018	Forecast 2019	Cumulative
1	PBR Decision reduction to base sustainment capital for Vancouver Island pressure	-	6.351	6.417	6.484	6.567	6.711	32.531
2	PBR Decision growth factor for net customer additions pressure	0.259	0.939	1.586	2.250	3.234	4.233	12.502
3	Regionalization Initiative	1.300	0.100	0.600	-	-		2.000
4	Installation of bypass (Jomar) valves	-	0.050	2.070	2.590	3.400	3.400	11.510
5	Increased in-line inspection activity	1.944	1.295	3.287	1.719	(2.547)	4.087	9.785
6	Unanticipated system improvements and new stations to supply gas to new customers	0.600	2.700	1.764	1.901	3.418	0.323	10.706
7	Whistler IP pipeline					10.273	1.454	11.727
8	Burns Bog stress relief	0.300	1.800	1.000	2.827	-	-	5.927
9	Other contributing factors:							-
10	PBR formula pressures resulting from increase in PIF (1.1% vs. 0.5%)	0.597	0.664	0.669	0.676	0.684	0.693	7.601
11	Prince George #1 lateral erosion	0.150	0.030	0.040	0.682	-	-	0.902
12	Ministry of Transportation and Infrastructure IP relocation		0.050	0.700		-	-	0.750
13	Mission IP seismic upgrade		1.200			-	-	1.200
14	Ashcroft Lateral Pipeline replacement due to flood erosion				1.308	1.269	0.743	3.320
15	Cyber security				0.423	0.500		0.923
16	Operations Fleet Requirements					6.000	1.250	7.250
17	**TOTAL Sustainment / Other Pressures**	5.150	15.180	18.134	20.860	32.798	22.895	92.122
18	**Actual annual and cumulative Sustainment / Other capital expenditures variance compared to formula**	1.825	(3.098)	2.588	26.311	35.732	27.244	63.358

Table A:B8-1-4 shows that in order for FEI to be able to manage its capital spending to a level close to the formula allowed amount in the years 2014 through 2016, some projects that were assessed as being less critical to the system, or that were temporarily less time sensitive, were reprioritized to future years to accommodate the required projects listed in the table. Starting in 2017, FEI has prioritized additional capital expenditures to start to catch-up on an accumulation of work that had been re-prioritized from previous years of the Current PBR term. For this reason, FEI's cumulative sustainment and other capital expenditure compared to formula is higher in 2017 to 2019 than the total of the items shown in Table A:B8-1-4.

FEI provides below a further discussion of each of the 2019 items in the table above, other than the formula-related items which are self-explanatory. Pressures for 2014 through 2018 were described in Appendix C-4 of FEI's Annual Review for 2019 Rates.

3.1 *INSTALLATION OF BYPASS (JOMAR) VALVES*

The installation of bypass valves (Jomar Valves) on residential meter sets was described further in Section 3.1, Appendix C4 of FEI's Annual Review for 2019 Rates Application.

3.2 *INCREASED IN-LINE INSPECTION ACTIVITY*

As described in Section 3.2, Appendix C4 of FEI's Annual Review for 2019 Rates Application, FEI needs to continue to enhance its Integrity Management Program to manage aging infrastructure, meet the CSA Z662-15 standard, and adopt industry practices deemed appropriate to FEI's system. Enhancements to FEI's in-line inspection activities include the adoption of the circumferential magnetic flux leakage technology with a run frequency of approximately seven years, and an increased number of transmission lines subject to in-line inspection.

3.3 *Unanticipated System Improvements and New Stations to Supply Gas to New Customers*

As described in Section 3.3, Appendix C4 of FEI's Annual Review for 2019 Rates Application, FEI forecasts the need for system capacity improvements due to typical growth of core customer load over 5-10 years using system capacity models. These forecasts make assumptions regarding the magnitude and location of load additions to the system based on housing development and growth trends known at the time. The higher than expected customer growth that has taken place during the Current PBR term, and the addition of large new customers has resulted in the need for system improvements and new stations to support the added load described in section 2. The need for capacity upgrades to the system has been well in excess of what was anticipated at the time of the 2014-2018 PBR Plan Application filing.

3.4 *Whistler IP Pipeline*

System capacity planning identified the need for significant capacity improvements to address load growth at the north end of the Whistler DP system. The project extended the existing intermediate pressure pipeline further into Whistler to the location of a new station and included the installation of additional distribution pipe to connect the station and reinforce the system. The project was initially planned to be phased over the course of three years with the majority of the costs incurred outside of the Current PBR period. The need for the later phases of the capacity upgrade was advanced due to higher than anticipated growth, and Whistler's conversion of its bus fleet to CNG. Additionally, the project met with significant delays in identifying a route that was acceptable to all stakeholders. As a result of the project delays and the increased customer load, the three phases of the project were compressed into 2018.

3.5 *Other Contributing Factors*

In addition to the Current PBR formula pressures, FEI has identified the following other contributing factors.

3.5.1 Ashcroft Lateral Pipeline Replacement Due to Flood Erosion

In the spring of 2017, flooding in the Ashcroft area caused Cache Creek to leave its previous channel and create a new channel that eroded the ground cover over the Ashcroft Lateral NPS 88 pipeline. Approximately 150 metres of pipeline needed to be replaced and lowered below the new creek profile. Further flooding in the spring of 2018 exposed additional sections of the pipeline. Two additional areas were remediated to restore ground cover over the pipeline during 2018. An additional three sites are planned for remediation in 2019.

3.5.2 Cyber Security

In 2019, FEI is continuing to implement cyber security measures to protect networks, computers and data from attack, theft, damage or unauthorized access. This initiative was introduced in FEI's Annual Review for 2018 Rates.

3.5.3 Operations Fleet Requirements

Fleet expenditures are related to the additional fleet and equipment requirements related to capital growth. FEI has identified new vehicle and equipment requirements associated with the addition of Operations headcount. The majority of the positions are related to construction crews required to assist with the increasing volume of growth capital projects.

3.5.4 CAD-USD Exchange Rates

This item was discussed above in Section 2.1.2.3. An increased cost of equipment and supplies purchased from the United States due to the unfavourable exchange rate is contributing to the sustainment / other capital cost variance.

3.5.5 Evolving Local Government Requirements

This item was discussed above in Section 2.1.2.4.

4. PROJECTS PLANNED TO BE UNDERTAKEN OUTSIDE OF CURRENT PBR TERM

The management of the capital plan is a dynamic and ongoing process and project timing is routinely shifted to accommodate changing conditions, such as resource constraints, permitting, material delays, project interdependencies, load changes and financial constraints. FEI reprioritizes capital spending as part of its routine management of the capital portfolio and has done so in prior years to accommodate unforeseen events and work, and to mitigate in part some of the pressures seen during the Current PBR term. However, FEI will not defer significant amounts of capital spending that would result in increased risk exposure.

Ssome projects that provide less value, or that are less time-sensitive, may be reprioritized to future years in favour of more urgent or valuable projects. Likewise, if additional capital is made available through project delays or cost savings, projects may be brought forward based on their assessed value and their ability to be successfully executed.

The base capital amount and annual formula adjustments were not derived from a list of future capital projects FEI planned to undertake each year during the Current PBR term. Rather, they were based on 2013 forecasts derived from historical capital expenditures. As such, FEI is unable to provide a comprehensive listing of projects that have been delayed, rescheduled, cancelled or added today against what was anticipated when the formula was developed.

However, the following is a list of the larger projects that FEI had identified for execution in the 2014-2018 PBR Plan Application but that have been delayed beyond the Current PBR term.

Table A:B8-1-5: Projects Delayed to Beyond the Current PBR Term

Description	Estimated Timing	Current Status
Class Location Upgrade: 765m (9 segments) of 1975 vintage 323mm OD East Kootenay Link Mainline, Salmo and Creston	2016	Planned for 2020 - 2021
Class Location Upgrade: 1319m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, West of Moyie River at Yahk	2017	Planned for 2022
Class Location Upgrade: 2782m (1 segment) of 2000 vintage 610mm OD Southern Crossing Pipeline, Grand Forks	2018	Planned for 2022
Tilbury LNG Plant Buildings	2018	Delayed to assess business requirements and site space strategy.
Distribution Main, Service Renewals and Alterations: Penticton Second Supply – Penticton	2015	Planned for 2019-2020.
The addition of pipe storage to the Burnaby Operations building	2014	Delayed due to further review of requirements for space strategy.

As described in the FEI 2014-2018 PBR Plan Application[6], FEI developed a forecast of Information Systems expenditures for the Current PBR period to allow for the implementation of projects to improve employee and public safety, address potential shortcomings in customer service levels and to drive O&M cost reductions. Information Systems expenditures are categorized under five main areas of focus including infrastructure sustainment, desktop infrastructure sustainment, application sustainment, business technology transformation and business technology enhancements. The annual portfolio under each category is continually evolving and individual projects are added or removed from the portfolio as required by the business. Each year is considered to be a new portfolio and projects are re-evaluated. As such, FEI does not have any specific IS projects that have been deferred to outside the Current PBR term.

5. CONCLUSION

FEI has taken a number of steps over the years to enhance and strengthen its internal capital prioritization processes. The AIP tool will allow the consistent quantification and evaluation of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

[6] Table C4-22, Section C4.6.4 of the FEI 2014-2018 PBR Plan Application.

Appendix B8-2

FEI DESCRIPTION OF CAPITAL CATEGORIES

FEI DESCRIPTION OF CAPITAL CATEGORIES

1.1 *FEI CAPITAL PLANNING PORTFOLIO HIERARCHY*

The capital planning portfolios are used to group similar types of work together for tracking purposes and for efficiency in planning, managing and executing the capital plan. Table A:B8-2-1 below shows the portfolio hierarchy used for the Capital Plan.

Table A:B8-2-1: Portfolio Hierarchy

Level 1	Level 2	Level 3	Level 4
FEI	Sustainment	Customer Measurement	Meter Materials
			Residential Meter Alterations & Exchange
			Small Commercial/ Industrial Meter Alterations & Exchange
			Large Commercial/ Industrial Alterations & Exchange
		Transmission System Reliability & Integrity	Pipeline Alterations
			Pipeline Capacity Improvements
			Pipeline Station Alterations
			Transmission System Telemetry Alterations
			Compressor Station Alterations
			Compressor Unit Overhauls
			LNG Plant Alterations
			Transmission System Cathodic Protection
			Pipeline Inspection
			Pipeline SRW Acquisition
		Distribution System Reliability	Distribution Stations Alterations
			Distribution System Telemetry Alterations
			Distribution System Capacity Alterations
			Distribution Stations New
			Revelstoke Propane Plant Alterations
			Distribution Sectioning Valves
		Distribution System Integrity	Main and Service Alterations
			Main and Service Renewals
			Service Hazards Mitigation
			Distribution Cathodic Protection
	Growth Capital	New Customer Mains	New Customer Mains
		New Customer Services	New Customer Services

Level 1	Level 2	Level 3	Level 4
		New Customer Meters	New Customer Meters
		System Improvements (DP)	System Improvements (DP)
	Other Capital	Equipment	Tools and Equipment
			Fleet Services
			Measurement Services
			Radio Communication
			Supply Chain
		Facilities	Facilities
		IS	Information Systems Sustainment
			Application Enhancements
			Cybersecurity
			Business Technology Applications

1.2 DESCRIPTION OF FEI CAPITAL PLANNING PORTFOLIOS

1.2.1 Sustainment Capital

1.2.1.1 Customer Measurement

1.2.1.1.1 METER MATERIALS

Meter materials expenditures are based on the meter exchange activity levels (scheduled and unscheduled) and the meter unit costs.

The level of meter exchange activity is the combined total of scheduled and unscheduled meter exchanges (residential, commercial and industrial) required so that customers continue to receive service that is both cost effective and reliable while remaining in compliance with regulatory requirements.

Scheduled meter exchange activity levels are driven by factors related to Measurement Canada's mandatory standards and regulations. Measurement Canada allows utilities to operate their meter fleets by applying a compliance sampling plan to confirm meters used for billing customers are accurate. Compliance sampling is the process of randomly selecting a subset of meters from a group of installed meters, testing the samples and inferring the quality of the remaining installed meters in that group from the test results of the samples.

Unscheduled meter exchanges occur as a result of unanticipated changes to customer metering needs, load changes as well as mechanical failures identified by a customer, a meter reader or other gas technician.

The meter unit cost is influenced by the type, the size, the design of the meter, the installation, fabrication and exchange conditions of the meter set and the timing of the bulk meter purchases and meter upgrade activity.

1.2.1.1.2 RESIDENTIAL METER ALTERATIONS & EXCHANGE

Residential meter alterations & exchange contain the labour component of completing the scheduled and unscheduled meter exchange, as well as the full cost of any customer or company initiated alterations for residential meter sets.

Residential meter set alterations are relatively consistent in volume and cost from year to year. Alterations are initiated for a variety of reasons, including customer load changes, alterations to the outside of the home or business, the correction of building code non-compliances, or the correction of observed hazards.

1.2.1.1.3 COMMERCIAL/INDUSTRIAL METER ALTERATIONS & EXCHANGE

The commercial/industrial meter alterations & exchange contain the labour component of completing the scheduled and unscheduled meter exchange, as well as the full cost of any customer or company initiated alterations for commercial and industrial meter sets.

The meter sets that are built to serve commercial and industrial customers can range from a simple meter and regulator configuration, to a TP/DP station that serves a single large customer. Consequently, commercial and industrial meter set alterations can be as simple as changing a regulator and meter for a load change, or as complex as a full station rebuild.

1.2.1.2 Transmission System Reliability & Integrity

1.2.1.2.1 PIPELINE ALTERATIONS

Pipeline alterations include the replacement or modification of pipelines or pipeline fittings to support the ongoing reliability and integrity of the asset. The majority of pipeline alterations are attributable to four main drivers: natural hazard mitigation, code compliance, operation and maintainability, or third party driven alterations.

Natural hazard mitigation is required to protect the pipeline from damage due to stream crossings, land movement, and seismic vulnerability. FEI has inspection programs in place that proactively monitor for emerging hazards. As threats to the integrity of the pipeline emerge, mitigation measures are designed and implemented in accordance with the severity of the threat. Although some of these hazards develop slowly over time and can be dealt with on a planned basis, others materialize very quickly and must be dealt with on an emergent basis.

Clause 4.3.2 of CSA Standard Z662, *Oil and gas pipeline systems*, defines limitations on operating stress (safety factor) based on the number of dwellings in proximity to the pipeline. An increase in the density of dwellings adjacent to a pipeline may result in the class location being changed, leading to a requirement to reduce the operating stress of the pipeline and thus increase the factor of safety. CSA Z662 also requires annual assessments of the class location to recognise and accommodate development near the pipeline. In instances where the class location is changed as a result of development, FEI must change the operating parameters of the pipeline. This may require reducing the operating pressure which leads to a loss of capacity and may limit the ability to meet customer demand. In instances where reducing operating pressure is unacceptable, the impacted section of pipeline must be replaced to meet the required safety factor while maintaining customer supply.

Investments that improve the ability to operate and maintain the system include replacing or installing new valves to allow effective isolation of the system for maintenance and emergency response, or removing obstructions and constrictions from the pipeline to allow the effective use of inline inspection tools to understand pipeline condition.

In addition to these planned modifications to pipelines, FEI is required to modify or relocate its pipelines at the request of third parties. This can take the form of pipeline crossings that require engineered structures or pipeline upgrades, or major provincial infrastructure projects that require pipeline relocation or upgrade. The cost for such modifications may be the responsibility of FEI or the requesting party, depending on any previous agreements in place.

1.2.1.2.2 PIPELINE CAPACITY IMPROVEMENTS

Pipeline capacity improvements include replacement, twinning, extensions and upgrades to increase transmission capacity and to ensure reliable delivery of natural gas to customers. The primary drivers of pipeline capacity improvements are load growth or improved reliability and resiliency.

1.2.1.2.3 PIPELINE STATION ALTERATIONS

Pipeline station alterations include the replacement or addition of equipment and components to support the ongoing safety and reliable operation of the transmission system. The pipeline stations on FEI's system require periodic replacement of equipment and components due to condition, obsolescence, load changes, and regulatory compliance.

1.2.1.2.4 TRANSMISSION SYSTEM TELEMETRY ALTERATIONS

Telemetry alterations are required for reliable communication of operating conditions to Gas Control. The telemetry systems require periodic replacement of equipment and components due to condition, obsolescence and code compliance.

1.2.1.2.5 COMPRESSOR STATION ALTERATIONS

Compressor station alterations include the replacement or addition of equipment and components to support the ongoing safety and reliable operation of FEI's compression facilities.

The compressor stations on FEI's system are an integral part of the transmission system and are critical for adequate gas supply for customers. The compressor stations require periodic replacement of equipment and components due to condition, obsolescence, and regulatory compliance.

1.2.1.2.6 COMPRESSOR UNIT OVERHAULS

The compressor stations on FEI's system are subject to recurring unit overhauls based on unit operating hours, as well as scheduled replacement of equipment and components due to condition, obsolescence, and regulatory compliance.

1.2.1.2.7 LNG PLANT ALTERATIONS

LNG plant alterations include the replacement or addition of equipment and components to support the ongoing safety and reliable operation of FEI's LNG facilities. The Tilbury and Mt. Hayes LNG plants play an important role in the operation of the FEI system. The two plants are peak shaving facilities that provide an alternate source of supply during peak demand days, during some types of pipeline work, or as a source of supply of LNG for use in planned or emergency work within FEI's distribution systems. Additionally, the plants are required to meet daily demands for FEI's transportation customers. Regardless of purpose, a high degree of reliability is required for these facilities.

1.2.1.2.8 TRANSMISSION SYSTEM CATHODIC PROTECTION

Clause 9.5.1 of CSA Standard Z662, *Oil and gas pipeline systems*, states that cathodic protection of new piping shall be applied no later than 1 year after installation, and shall be maintained. CP projects include the installation or replacement of anode beds, rectifiers and remote monitoring units (RMUs) to ensure the ongoing cathodic protection of the transmission system.

1.2.1.2.9 PIPELINE INSPECTION

Pipeline inspections include in-line inspections using smart tools, as well as major waterway underwater crossing inspections.

In-line inspection programs are developed based on the age, attributes, and condition of the pipeline. Inspection frequencies typically range from five to seven years. Tools are selected based on the specific attributes of the pipeline to detect a range of features and condition deterioration mechanisms that the pipeline could be susceptible to.

Underwater crossing inspections are carried out every five years on a scheduled basis to inspect the external condition of pipelines that were installed by laying the pipe at bottom of the waterbody.

1.2.1.2.10 PIPELINE SRW ACQUISITION

The acquisition of statutory rights of way (SRW) is required for safe and compliant installation of transmission pipelines. The acquisition of new SRW is required where no SRW has been established or existing SRW cannot be used. Additional SRW projects may arise from pipeline trespass discovered by survey or third-party notification.

1.2.1.3 Distribution System Reliability

1.2.1.3.1 DISTRIBUTION STATIONS ALTERATIONS

Distribution stations alterations include the replacement or addition of equipment and components at distribution pressure regulating stations to support the ongoing safe and reliable operation of the distribution system. The pressure regulating stations on FEI's system require periodic replacement of equipment and components due to condition, obsolescence, load changes, and regulatory compliance. Some examples of typical investments in this category include:

- Replacing station RTUs due to equipment obsolescence.
- Upgrading the line heater and/or regulators to meet increased station load.
- Upgrade of odorization equipment to prevent over or under odorization.

1.2.1.3.2 DISTRIBUTION SYSTEM TELEMETRY ALTERATIONS

Telemetry alterations are required for reliable communication of operating conditions to Gas Control and to record information that is used in the planning and operation of the distribution system. The telemetry systems require periodic replacement of equipment and components due to condition, obsolescence and code compliance.

1.2.1.3.3 SYSTEM CAPACITY ALTERATIONS

System capacity alterations occur when additional mains are required to be installed within the existing network to increase system capacity in order to meet peak customer demand. Capacity alterations are required to address low pressure areas in the distribution system that arise due to increased customer demand and new customer additions within the service area. As of 2020, this category only includes intermediate pressure system improvements

1.2.1.3.4 DISTRIBUTION STATIONS NEW

New stations may be installed to provide added capacity and/or to improve reliability and resilience to a distribution system by providing a second source of supply. They may also replace an existing station to improve the system pressures and/or improve our ability to safely maintain the station.

1.2.1.3.5 REVELSTOKE PROPANE PLANT ALTERATIONS

Revelstoke propane plant alterations include the replacement or addition of equipment and components at the Revelstoke propane plant to support the ongoing safe and reliable operation of the propane system. The Revelstoke propane plant requires periodic replacement of equipment and components due to condition, obsolescence, load changes, and regulatory compliance.

1.2.1.3.6 DISTRIBUTION SECTIONING VALVES

Distribution sectioning valves are used in case of emergencies to isolate portions of the system to ensure public safety by minimizing the release of gas and avoiding impact to the rest of the distribution system.

1.2.1.4 Distribution System Integrity

1.2.1.4.1 MAIN AND SERVICE ALTERATIONS

Main and service alterations expenditures can be initiated by FEI, by customers, or by a third party. FEI may initiate the work to address hazards, to replace aging assets, or to meet internal or external standards. A customer may initiate an alteration to accommodate renovations at their home or to increase the size of the service. A third party, such as a municipality or developer. may initiate an alteration to accommodate other subsurface or infrastructure work that they are undertaking. Their work often necessitates that FEI cut out or abandon an existing section of pipe and install new pipe in a new alignment. The cost of these replacements may or may not be recoverable from the party initiating the work, depending on the terms of any agreement or permit that exists.

Addition or alteration of non-sectioning valves also falls under this sub-portfolio. Valves must be NPS 6 or larger in order to qualify as capital.

1.2.1.4.2 MAIN AND SERVICE RENEWALS

Main and service renewals are initiated by FEI to manage the replacement of aging and poor condition mains and services over time. FEI uses asset leak history and condition assessments to identify gas mains that are more likely to have integrity-related concerns and proactively schedules them for replacement. By assessing and planning the projects in this manner the replacement work can be undertaken at a lower cost than numerous unplanned repairs, and the work will be less disruptive to municipalities, the public and FEI's customers. Further, with sufficient assessments completed, the replacement projects can be coordinated with municipal infrastructure upgrades thus reducing the impact on the public further.

1.2.1.4.3 SERVICE HAZARDS MITIGATION

Service hazards mitigation expenditures include the alteration of services to address hazards or code non-compliance issues that impact the safety or integrity of a customer service. These hazards are often the result of property alterations conducted by homeowners.

1.2.1.4.4 DISTRIBUTION SYSTEM CATHODIC PROTECTION

Distribution cathodic protection expenditures include the replacement, upgrade or addition of components that support the cathodic protection system to prevent corrosion on buried distribution assets. Examples of expenditures in this category include:

- Replacement or installation of rectifiers;
- Replacement or installation of anode beds;
- Installation of new isolation devices (electrostops); and
- Projects to remove electrical shorts from the system.

1.2.2 Growth Capital

1.2.2.1 New Customer Mains

Main expenditures consist of new main extensions with a number of different attributes including location, size of pipe, and length of extension, pressure and type of material. Proposed main extension projects are evaluated through a BCUC approved main extension test (MX Test). The MX Test includes inputs such as the cost estimates for installing the main, projections in the numbers of customers attaching, along with an estimate for consumption based on an average consumption value per appliance. If the main extension does not meet the MX Test threshold, a contribution from the customer is required in order for the planned extension to proceed. These contributions are recorded as CIAC.

1.2.2.2 New Customer Services

Service expenditures consist of a variety of service types for new customers. These include new and conversion, distribution and intermediate pressure services to single and multi-family dwellings, gas stub service from the main, services installed from the stub, vertical header subdivisions (a vertical service line system within a building such as a high-rise) and distribution and intermediate new or conversion service header mains, and distribution and intermediate service header laterals. Service header mains are distribution mains installed on private property (i.e., multi-family strata owned complexes). Stubs are service extensions off of the main installed with the main in new subdivisions to eliminate road cuts and pavement repairs at a future date.

Residential customer service attachments can be for a single family dwelling attachment where there is typically one gross customer addition (one new meter) associated with each new service line, or for multi-family dwellings such as townhomes where there may be one riser with multiple meters and dwellings. Where multiple meters are installed to one service line, the gross customer additions are greater than the service line installations and are equal to the number of new meters installed.

The BCUC approved Service Line Cost Allowance (SLCA) is used to evaluate customer contributions for gas service connections for infill residential and small commercial customers to *existing* mains, where only a service line is required. For services that exceed the SLCA, a contribution is required and these contributions are also recorded as CIAC.

1.2.2.3 New Customer Meters

This category includes to cost to install new meter sets (meter, regulator, valves, piping and fittings) required to serve new customers.

1.2.2.4 System Improvements (DP)

System improvements occur when additional mains are required to be installed within the existing distribution network to increase system capacity in order to meet peak customer demand. Expenditures in this category are driven by customer additions that necessitate upgrades to system capacity to maintain reliable service to existing and new customers. These system improvements are sometimes triggered over time by growth of core customers, and other times by a single large customer that attaches to the system.

1.2.3 Other Capital

1.2.3.1 Equipment Capital

1.2.3.1.1 TOOLS AND EQUIPMENT

This category includes tools and equipment which allow employees to do their jobs safely, efficiently and at a level expected for the business. The tools and equipment budget is used to purchase and/or replace tools and equipment that have a value greater than $1,000 and are required by various technical and trades employees. New tools and equipment are purchased to improve ergonomics, meet new requirements, or replace outdated and worn tools and equipment.

1.2.3.1.2 FLEET SERVICES

This category includes the replacement and/or acquisition of heavy fleet vehicles, light duty vehicles, passenger vehicles, service vehicles, specialty equipment and off road vehicles necessary to meet the operational requirements of FEI.

Many factors are taken into consideration when an actual vehicle replacement decision is made. Factors such as suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, and compliance with regulations, are reviewed when vehicles are near the end of their planned service life. Each replacement decision is evaluated on a unit-by-unit basis. Measurement Services.

1.2.3.1.3 MEASUREMENT SERVICES

Measurement Services capital includes the replacement of worn and out dated tools and equipment in the meter shop. This category of funding is also used to purchase new tools and equipment to increase safety and efficiency. The tools and equipment includes racking, gas leak detectors, gas meter proving systems, leak detectors, and temperature standards.

1.2.3.1.4 RADIO COMMUNICATIONS

Radio communications capital includes the purchase of replacement and new equipment to maintain the VHF, Microwave, and UHF communications systems for dispatching, emergency communications, and SCADA signals. The equipment includes handheld radios, truck radios, and tower and dish upgrades to meet radio network standards.

1.2.3.1.5 SUPPLY CHAIN

This category of funding is used to replace, upgrade and purchase new tools and equipment for the weld shop, prefabrication shop and stores. The tools and equipment includes arc welders, cutters, meter cages, pallet jacks, and machinery that make the shops and stores safer and more efficient.

1.2.3.2 Facilities

Facilities capital expenditures include the acquisition or leasing of land, buildings, and facilities furniture and equipment. FEI's facilities capital expenditures focus primarily on capacity planning, upgrading and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet Company standards, building codes and regulations, and provide a long term solution toward meeting the business requirements.

FEI has 55 non-plant office and muster sites with buildings ranging from 1 year to over 100 years in age. When it is determined that an asset facility is no longer adequate, FEI will decide whether to upgrade, replace or add assets depending on condition, age and capacity to provide a suitable work environment with safe and efficient buildings and workspaces.

1.2.3.3 Information Systems

FEI's Information Systems expenditures focus on enhancing, replacing, upgrading and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency. FEI relies on a base of core enterprise applications, including SAP (Customer Service and Billing, Financial, Human Resources, Plant Maintenance and Materials Management), SharePoint, and AM/FM (Asset and Facilities Management). These applications are used to support FEI's business technology requirements. FEI selected these core systems for their scalability and technology which allow them to be upgraded, enhanced and integrated thereby minimizing the need to acquire and implement new business technology solutions.

1.2.3.3.1 IS SUSTAINMENT

Infrastructure Sustainment is the non-discretionary capital funding required to replace or upgrade outdated or end-of-life hardware and server software in the data centres. This includes servers, operating systems, LAN and WAN equipment, etc.

End-user device Sustainment is the capital funding required to replace or upgrade end user equipment and software. This includes PCs, operating systems, desktop applications, printing equipment, all mobile devices, etc.

Application Sustainment is the capital funding required to sustain existing software applications. This includes required upgrades to maintain support, reliability and performance of existing applications not including data centre software.

1.2.3.3.2 APPLICATION ENHANCEMENT

Application enhancement is the capital funding to modify the functionality or enable capabilities of existing applications to meet annual business requirements with priority on safety and customer service. This includes interfaces, enabling new functionality, enhanced reporting, etc.

1.2.3.3.3 CYBERSECURITY

Increased sophistication in cyber threats has forced hardware and software companies to release updated code and operating systems to counteract these threats. The frequency of these updates have forced the business to engage in testing, custom configuration and code updates to deploy the updates. Tools to monitor and counteract these threats have to evaluated and implemented to maintain an acceptable level of cybersecurity.

1.2.3.3.4 BUSINESS TECHNOLOGY APPLICATIONS

This category includes capital funding for initiatives that impact the way business is conducted and that support business unit's priorities. This includes the introduction of new technologies to meet business requirements, system integration that changes business processes and/or the introduction of new business processes and harmonization of systems that benefit both FEI and FBC.

Appendix B8-3

FBC CAPITAL DIRECTIVES

FBC CAPITAL DIRECTIVES

1. INTRODUCTION

In Order G-38-18, at page 14, the BCUC set out the following capital directive.

> The Panel directs FBC to provide the following information related to capital in its annual review of 2019 rates application:
>
> - A breakdown and explanation for both the annual variances (2014–2018) and cumulative variances between forecast/actual and formula capital which quantifies the variances attributable to the following factors:
>   - System improvements to accommodate customer growth;
>   - Customer driven modifications at RG Anderson Terminal;
>   - Increased costs due to unfavourable exchange rate;
>   - A list of work prioritized from previous years by project, including the capital cost and the previously scheduled dates and classifications (i.e., mandatory, essential or flexible);
>   - New projects in generation to address compliance with new WorkSafeBC legislation;
>   - Unanticipated transmission projects to address safety and reliability issues;
>   - Additional substation projects to address end-of-life equipment replacements; and
>   - Any other significant factors or miscellaneous items.
> - A description of how FBC is prioritizing its capital expenditures during the remainder of the 2014-2019 PBR term (Current PBR term), with reference to the prioritization ascribed to its existing ongoing projects as well as any new projects to be undertaken during the Current PBR term.
> - A list of projects that were originally planned to be completed during the Current PBR term that are now expected to be delayed until after the Current PBR term, including a description of the project, reason for the delay, the estimated capital cost, classification and the year for which it was originally planned.

Further, in Order G-246-18 in FBC's Annual Review for 2019 Rates, the BCUC stated in Directive 4:

> FBC is directed to continue providing the information related to capital that is in Table 1-3 and Appendix B2 of the Application in its next revenue requirements application, which is expected to be filed with the BCUC in 2019.

Table B2-6 in Section B2 of the MRP Application shows the annual and cumulative variances between actual/projected and formula capital expenditures. In this Appendix, FBC provides the requested information for each of the remaining areas described in Order G-38-18.

2. ANNUAL CAPITAL VARIANCES

In the table below, FBC provides a breakdown and itemization of variances attributable to the items identified by the BCUC.

Table A:B8-3-1: Annual Capital Variances ($ millions)

Line No.	Description	2014	2015	2016	2017	2018	2019P	Cumulative
1	Growth factor reduction for net customer additions	0.140	0.080	0.260	0.220	0.290		0.980
2	X factor increase by 0.53 percent	0.230	0.230	0.230	0.240	0.250		1.170
3	System improvements to accomodate growth	2.000	2.000	2.000	2.600	5.205	2.900	16.705
3a	Customer-Funded Projects					0.552		0.552
4	Highway 97 Kelowna/ Hwy 22 Castlegar MOTI	0.100	0.400	2.400	0.700	0.105	0.900	4.605
4a	Relocation of 42L north of Oliver substation						1.300	1.300
5	Customer-driven modifications at RG Anderson Terminal			0.100	2.700	0.856		3.656
6	New Generation projects to address compliance with WorkSafeBC legislation (guarding of rotating parts and floor covers)			0.140	0.140	0.584	0.198	1.062
7	New Generation projects to address compliance with WorkSafeBC legislation (single device isolation)					0.254	0.195	0.449
8	Unanticipated transmission projects to address safety and reliability issues					0.456	0.050	0.506
9	Substation projects to address end of life equipment replacements				1.200	0.600		1.800
10	Other contributing factors:							
11	Weather events					1.899		1.899
12	Evolved project definition				1.900			1.900
13	Project re-prioritization				4.000	1.880	0.705	5.880
14	Cyber security				0.125	0.215		0.340
15	**TOTAL Capital Pressures**	2.470	2.710	5.130	13.825	13.146	6.248	42.804
16	**Annual and cumulative capital expenditures variance compared to formula**	0.472	2.408	2.964	15.799	16.369	11.638	49.650

Table A:B8-3-1 shows that in order for FBC to be able to manage its capital spending to a level close to the formula allowed amount in the years, 2014 to 2016, some projects that were assessed as being less critical to the system, or that were temporarily less time-sensitive, were reprioritized to future years to accommodate the required projects listed in the table. In 2017 and 2018, FBC prioritized:

- additional capital expenditures to start to catch up on an accumulation of work that had been re-prioritized from previous years of the Current PBR term; and

- new projects that were identified to address safety, compliance, reliability issues and to replace end of life of equipment.

In 2019, FBC will complete the re-prioritized work from prior years.

FBC anticipates capital expenditures to exceed the formula in 2019 due to factors including:

- New projects in generation to address compliance with legislation from WorkSafeBC;
- Unanticipated transmission projects to address safety and reliability issues;
- Additional substation projects to address end-of life equipment replacements;
- Purchase of fibre from Shaw Cablesystems Limited due to contractual obligations; and
- Addition of the Sexsmith Distribution Transformer to accommodate capacity requirements.

FBC provides below a further discussion of each of the 2019 items in the table above, other than the formula-related items which are self-explanatory. Pressures for 2014 through 2018 were described in Appendix B2 of FBC's 2019 Annual Review for 2019 Rates.

2.1 *SYSTEM IMPROVEMENTS TO ACCOMMODATE CUSTOMER GROWTH*

System improvements are projects related to increased capacity, equipment and services upgrades, voltage regulation, feeder ties, and load transfers, which are required to keep pace with normal load growth on the transmission and distribution systems. They also include work to connect new customers and to ensure continuing acceptable standards of service.

2.2 *FORCED UPGRADE PROJECTS*

There are two significant Forced Upgrade projects with expenditures forecast in 2019:

- Ministry of Transportation and Infrastructure (MOTI) driven line relocation in Castlegar.
- Relocation of 42L north of Oliver substation.

The MOTI project will be partially offset by CIAC. The 42 L project is customer-funded and offset by CIAC. CIAC is excluded from the capital expenditure formula envelope.

2.3 NEW GENERATION PROJECTS TO ADDRESS COMPLIANCE WITH WORKSAFE BC LEGISLATION

Ongoing Generation pressures in 2019 are due primarily to Occupational Health and Safety (OHS) requirements under WorkSafe BC legislation[1] including:

- Compliance with OHS rules related to guarding of rotating parts - OHS 12.16 and OHS 12.3;
- Compliance with OHS rules for platforms - OHS 4.59 related to the load rating of hatches, plates and covers; and
- Compliance with OHS 9.18(3)(b) rules related to single device isolation certification.

2.4 UNANTICIPATED TRANSMISSION PROJECTS TO ADDRESS SAFETY AND RELIABILITY ISSUES

There is one unanticipated transmission project in the Crawford Bay area required to address safety and reliability concerns:

- Improvements to the Right of Way conditions along the 30L transmission line (63kV line) from Nelson to Coffee Creek substation to manage vegetation growth and to reduce the number of tree-contact related outages.

2.5 SUBSTATION PROJECTS TO ADDRESS END OF LIFE EQUIPMENT REPLACEMENTS

The work required in the Generating station switchyards in 2019 is:

- Due to the poor condition of the beams and protection equipment, FBC will replace the 69 kV bus wood beams and pin and cap insulators at UBO;
- Due to major oil leaks and dissolve gas analysis results, FBC will re-gasket and conduct oil refurbishment for LBO transformers T1 and T2;
- Due to damage as a result of improper use and condition of equipment, FBC will replace the UBO Outdoor Low Voltage AC Distribution Panel.

[1] FBC notes that in its response to the BCUC IR 12.4 related to FBC's Annual Review for 2018 Rates has incorrectly attributed the capital expenditures increases in 2018 related to Generation projects to new WorkSafeBC legislation. Requirements are outlined in existing WorkSafeBC OHS legislation.

2.6 OTHER CONTRIBUTING FACTORS

In addition to the Current PBR formula pressures, FBC has identified the following other contributing factors.

2.6.1 Weather Events

In 2019 to date there have been no significant weather related events necessitating urgent repairs, so weather events have placed negligible pressure on the sustainment capital funding to date. Weather events are unpredictable and FBC strives to maintain service and to restore power as soon as possible during weather related events.

2.6.1 Evolved Project Definition

FBC is executing projects that were first scoped and estimated in 2011 for the 2012 Long Term Capital Plan (on which the 2014 PBR capital formula was based). Changes in equipment condition compared to that expected and other project requirements have resulted in increased costs. During detailed design the project definition is improved and cost estimates are updated to reflect changes.

2.6.2 Project Re-prioritization

The following is a list of work prioritized from previous years into 2019, including the priority (as set out in Section 3.1 below) assigned to each item:

- Rooftop HVAC replacement for non-compliant refrigerant (Mandatory). This multi-year project was deferred from starting in 2015 to 2016 due to capital cost pressures. The 2019 forecast is $0.250 million.
- Underground switcher replacement scope for a distribution feeder in Kelowna (Essential). This project was deferred from 2018 due to capital cost pressures. The 2019 forecast cost is $0.100 million to complete.
- Generation project for UBO T5-T6 low voltage cable and supports upgrade (Essential). This project was deferred from 2018 due to capital cost pressures. The 2019 forecast cost is $0.188 million to complete.
- Generation project for UBO station service circuit breaker decommissioning (Essential). This project was deferred from 2018 due to capital cost pressures. The 2019 forecast cost is $0.069 million to complete.
- FBC stations minor plant sustainment scope for several substations throughtout the service territory (Essential). These projects were deferred from 2018 due to capital cost pressures or outage constraints. The 2019 forecast cost is $0.100 million to complete.

2.6.3 Cyber Security

In 2019, FBC is continuing to implement cyber security measures to protect networks, computers and data from attack, theft, damage or unauthorized access. This initiative was introduced in FBC's Annual Review for 2018 Rates[2].

2.6.4 Exchange Rates

The Canada-United States exchange rate forecast, on which FBC based its capital cost assumptions for the PBR term, was higher than the exchange rates that have been realized during the PBR term. FBC's Base Capital for the Current PBR Plan was determined from 2013 Approved levels, which were based on a CAD/USD exchange rate forecast of $0.97. Thus, FBC's Base Capital was set based on an expectation that the exchange rate would be close to par, whereas capital expenditures during the Current PBR term have been incurred at an exchange rate closer to 0.8[3]. This causes capital cost pressure on FBC's formula-driven expenditures under the Current PBR Plan as many of FBC's major equipment purchases are from outside Canada and are denominated in USD currency.

For the majority of capital items, the impact of these unfavourable exchange rates cannot be specifically quantified. Apart from the services and materials that FBC sources directly from the United States, there are large volumes of materials that are sourced from Canadian distributors where the higher cost of goods is passed on to FBC according to the terms of the contract. FBC's vendor contracts can have a negotiated currency clause that governs the treatment of fluctuations in exchange rate between the two parties and the terms of that clause could be different for each vendor. Services and materials for capital projects are also often negotiated specifically based on a detailed scope of work for the project and are therefore subject to the economic conditions and exchange rates in place at that time. The individual contribution of the various drivers on price cannot be isolated, and as a result, FBC is unable to quantify the impact of the unfavourable exchange rate on capital costs from inflationary pressures and other variables that drive service and material costs.

3. CAPITAL PRIORITIZATION

In this section, FBC provides a discussion of how capital expenditures are prioritized during the Current PBR term, with reference to the prioritization ascribed to its existing ongoing projects. This includes a description of any projects which were originally planned to be completed during the Current PBR term but are now expected to be delayed until after the Current PBR term. New projects undertaken or anticipated during the remainder of the Current PBR term are identified in Section 2 above.

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2 FBC Annual Review for 2018 Rates, page 4.

3 Average 2014 through 2018 Bank of Canada indicative CAD/USD exchange rate (2014: 0.91, 2015: 0.78, 2016: 0.76, 2017: 0.77 , 2018: 0.78)

Prioritization of capital expenditures has been an evolving process and FBC has taken a number of steps over the years to improve its internal capital prioritization processes.

FBC provides below a description of its current capital expenditure prioritization processes.

3.1 CURRENT CAPITAL PRIORITIZATION PROCESS

Higher expenditures for customer growth capital during the Current PBR term have led to capital expenditure pressures in other areas of the organization. This growth capital pressure has been partially offset by FBC reprioritizing some sustainment work that is flexible in timing. However, as a public utility, FBC is required to provide service, and as such, FBC considers the capital expenditures associated with customer growth to be mandatory.

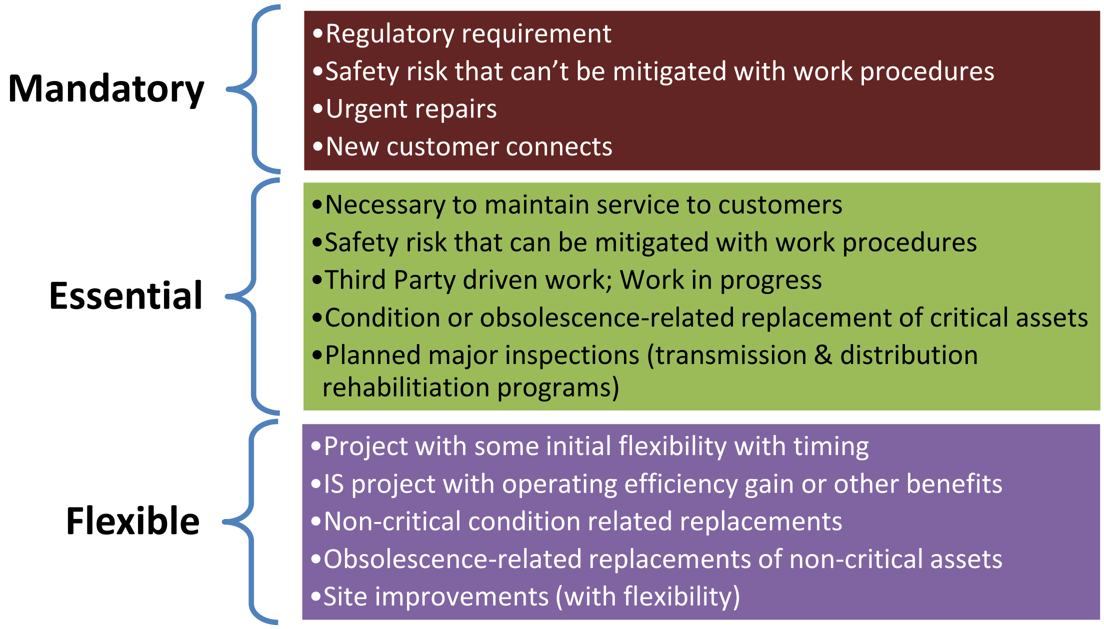
To date during the Current PBR term, capital expenditures, including new projects required to address safety, compliance, reliability issues and to replace end of life of equipment, but excluding non-discretionary growth capital, have been prioritized through the following steps:

Step 1: Within the various planning groups of electric assets sustainment and general plant (e.g. Information Systems (IS), Fleet and Facilities), capital investments are prioritized through established asset-specific means. Criteria such as asset health/condition, number of customers served, location, reliability indices, and operating cost opportunities are considered through a project portfolio management process that strives to quantify the benefit of the proposed projects. IS projects are prioritized through the Project Portfolio Management process that quantifies the benefit of the proposed projects[4].

Step 2: In addition to this asset specific prioritization, during the development of the 2016 capital plan, FBC began assigning each project to one of the three classifications in the figure below

[4] IS Capital Prioritization using Project Portfolio Management and Benefits Management Practice is described in Appendix C-4 response to 2012-2013 RRA Decision BCUC Directive No. 42.

Figure A:B8-3-1: Capital Priority Classification



Step 3: Based on the three classifications set out in Figure A:B8-3-1, available funds and resources were allocated towards mandatory and essential work first. As funds were anticipated to be insufficient to cover the proposed scope of flexible work, further analysis was completed as described in Step 4.

Step 4: Projects that were classified as Flexible in the subject year were subject to further analysis to determine which ones would proceed in that year and which ones would be rescheduled to future years. This analysis included an evaluation of risk mitigation, financial performance, customer growth, customer service, and employee engagement.

Step 5: Once the year's plan is approved and released, plan execution is monitored and adjustments are made as required. For example, in 2014 through 2017, growth expenditures were higher than anticipated which caused other work to be reprioritized to later years.

3.2 *PLANNED IMPROVEMENTS TO THE CAPITAL PRIORITIZATION PROCESS*

In recognition of the importance of consistently valuing and prioritizing its investments, and in light of recent capital pressures that are expected to continue, FEI and FBC (collectively FortisBC or the Companies) have been building on and enhancing their capital planning process to further align capital investment decision-making across the Companies and leverage the available tools, processes and systems. The planned improvements to the capital prioritization process are described in greater detail in Section C3.1 of the MRP Application.

3.3 PROJECTS PLANNED TO BE UNDERTAKEN OUTSIDE OF CURRENT PBR TERM

FBC reprioritizes capital spending as part of its routine management of the capital portfolio and has done so in prior years to accommodate unforeseen events and work, and to mitigate in part some of the pressures seen during the Current PBR term. However, FBC will not defer significant amounts of capital spending that would result in increased risk exposure.

The base capital amount and annual formula adjustments were not derived from a list of future capital projects FBC planned to undertake each year during the Current PBR term. Rather, they were based on 2013 forecasts. As such, FBC is unable to provide a comprehensive listing of projects that have been delayed, rescheduled, cancelled or added today against what was anticipated when the formula was developed. However, the following is a list of the larger projects that FBC had identified for execution in the Current PBR Plan but that have been delayed beyond the Current PBR term.

Table A: B8-3-2: Projects Delayed to Beyond the Current PBR Term

Name-Description	Estimated Cost (million)	Original Schedule	Current Status
Glenmore Low Voltage Bus Capacity Upgrade Upgrade the 1200 amp rated low voltage bus and three bus tie switches at Glenmore substation to a 2000 amp rating.	$ 0.2	2017	Delayed indefinitely due to redistribution of load
The Summerland Substation transformer: Required to supply the District of Summerland municipal utility with a distribution wholesale supply. The load on the existing Summerland T1 transformer was forecast to exceed 95 percent of the contract Demand Limit in 2015. Under the terms of the wholesale supply agreement, FBC would be required to upgrade the supply capacity in order to continue to provide reliable service.	$7.0	2015	Will be reviewed in the near future due to lower load growth than previously forecast.
Grand Forks Terminal Feeder Addition Additional feeder to supply Christina Lake from Grand Forks Terminal station	$5.0	2016-2017	Delayed. To be reviewed once the Grand Forks Terminal Station Reliability project is completed.
DG Bell 4 Feeder Addition Currently the DG Bell substation has three feeders with a spare breaker available for a future feeder. The original planned solution was to make use of the spare breaker and add a fourth feeder to the station in order to offload the existing load	$1.8	2018	Planned for 2020. Delayed to coordinate with a City of Kelowna project.
Okanagan Long Term Solution Procurement of land to construct a FBC Facility in Kelowna	$12.0	2016	Delayed due to land procurement challenges.

As described in the 2014-2018 PBR Plan Application[5], FBC developed a forecast of Information Systems expenditures for the Current PBR period to allow for the implementation of projects to improve employee and public safety, address potential shortcomings in customer service levels and to drive O&M cost reductions. Information Systems expenditures are categorized under four main areas of focus including information systems sustainment, cyber security, application enhancement, and business technology applications. The annual portfolio under each category is continually evolving and individual projects are added or removed from the portfolio as required by the business. Each year is considered to be a new portfolio and projects are re-evaluated. As such, FBC does not have any specific IS projects that have been deferred to outside the Current PBR term.

3.4 *CONCLUSION*

FBC has taken a number of steps over the years to enhance and strengthen its internal capital prioritization processes. In 2019, FBC is using the AIP tool for the 2020 – 2024 capital prioritization. The AIP tool will allow the consistent quantification and evaluation of benefits and risk mitigation associated with each proposed investment and the optimization of the capital portfolio across asset types and business units.

[5] Table C4-22, Section C5.6.1 of the FBC 2014-2018 PBR Plan Application.

Appendix B9

FEI REVIEW OF BVA TRANSFER MECHANISM AND INTERCONNECTION COSTS

FEI REVIEW OF BVA TRANSFER MECHANISM AND INTERCONNECTION COSTS

1.1 *INTRODUCTION*

This appendix reports on the results of FEI's review of the Biomethane Variance Account (BVA) Balance Transfer mechanism. FEI completed this review in compliance with Directive 12 of the BCUC's Decision on FEI's Application for Approval of Biomethane Energy Recovery Charge Rate Methodology (BERC Rate Methodology Decision) issued on August 12, 2016. Directive 12 ordered FEI to review the BVA Balance Transfer mechanism at *"the earlier of four years or an application for an inventory transfer from the BVA to the MCRA, or FEI's approach to ratemaking (i.e. PBR to cost of service)".*

Based on FEI's review of the current BVA Balance Transfer mechanism, FEI concludes that it is operating as designed and is both simple and transparent. Therefore, FEI proposes to continue with the existing BVA Balance Transfer mechanism through this MRP term. In FEI's comprehensive assessment report on the Biomethane Energy Recovery Charge (BERC) rate methodology directed to be filed by August 12, 2020 by Order G-133-16[1], FEI will consider again the potential need for changes to the BVA Balance Transfer mechanism in the context of any proposed changes to the biomethane program arising out of that report.

While FEI is proposing to continue with the current BVA Balance Transfer mechanism, FEI is requesting one change to the regulatory treatment of certain biomethane costs. Specifically, FEI proposes that the interconnection costs for FEI's first seven interconnection facilities that were approved as part of the biomethane pilot project, and that are currently recovered in delivery charges, be accounted for in the BVA. This would be consistent with the treatment of the costs of all other interconnections, which are accounted for in the BVA. Given the approved BERC rate methodology, there is no longer a need to keep the seven interconnections outside of the BVA.

1.1 *BVA BALANCE TRANSFER MECHANISM – CLEAR AND TRANSPARENT*

The BVA Balance Transfer Mechanism is working as intended and continues to provide clear and transparent information regarding the costs of the program, the recoveries from biomethane customers and the costs transferred from the BVA to the BVA Rider Account for recovery from non-bypass customers. The BCUC outlined one issue with respect to the BVA Balance Transfer mechanism that FEI proposed in its Biomethane Energy Recovery Charge Rate Methodology Application filed on August 28, 2015.

[1] G-133-16 dated August 12, 2016, Directive 16.

> Does the proposed BVA Balance Transfer mechanism provide customers with an understanding of the true cost of the program?[2]

There are three reports that FEI produces each year to ensure transparency of Biomethane program costs.

FEI's Fourth Quarter Gas Cost Report includes actual, projected and two years of forecasted biomethane purchase and production costs, purchase and production volumes, sales volume and cost recoveries[3] by rate schedule and an aged inventory report. This report provides a forecast of the costs to procure and produce biomethane and also a forecast of the expected recovery of program costs from biomethane customers. The report also provides a forecast of the costs to be transferred to the BVA Rider Account.

FEI's Annual Review contains the calculation of the costs transferred to the BVA Rider Account and the determination of the riders by rate schedule. The BVA cost transfer includes a true-up of the previous year's forecast of costs transferred to the account, a forecast of costs transferred to the account from the BVA[4], a projected recovery of costs in the account and, finally, a calculation of the BVA rider by rate schedule for the upcoming forecast year.

Finally, the BVA Status Report (filed Annually) reconciles the previous years' actuals with forecast including the actual costs transferred to the BVA Rider Account.

Together these reports provide transparency of Biomethane program costs and the cost of the program that are borne by all non-bypass rate payers through the transfer and calculation of the BVA rider.

In the Decision to FEI's Biomethane Energy Recovery Charge Rate Methodology Application both the BCSEA[5] and CEC[6] agreed with the mechanism proposed and BCOAPO[7] was not opposed.

FEI concludes that the BVA Balance Transfer Mechanism is operating as designed and is both simple and transparent. Therefore, FEI proposes to continue with the existing BVA Balance Transfer mechanism through this MRP term or until FEI files its comprehensive assessment report on the Biomethane Energy Recovery Charge (BERC) rate methodology directed to be filed by August 12, 2020.

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[2] Order G-133-16, Decision page 39
[3] Through the BERC rate
[4] Updated from the Fourth Quarter Gas Cost Report
[5] Order G-133-16, Decision page 44
[6] Ibid
[7] Ibid

1.2 *REGULATORY HISTORY – INTERCONNECTION COSTS*

On June 8, 2010, FEI filed an Application for Approval of a Biomethane Service Offering and Supporting Business Model (2010 Biomethane Application). The 2010 Biomethane Application sought approval of the necessary tariff provisions, cost allocation methodology and accounting treatment to allow the Company to introduce an end-to-end business model for the acquisition of Biomethane supply and the sale of a renewable energy. The 2010 Biomethane Application proposed to recover from all distribution customers the costs to connect the biomethane supply sources to FEI's distribution system (interconnection costs). The application also proposed the creation of the BVA to capture the cost of purchasing biomethane and raw biogas and the costs to upgrade the raw biogas to biomethane (production costs). The recovery of costs in the BVA were to be from Biomethane customers through the BERC rate. In the Order and Decision to the 2010 Biomethane Application the BCUC approved the cost allocation methodology proposed by FEI for the 2 year pilot period[8]. FEI was approved to recover interconnection costs from all customers and production costs from Biomethane customers.

On December 19, 2012 FEI filed the Biomethane Service Offering: Post Implementation Report and Application for Approval of the Continuation and Modification of the Biomethane Program on a Permanent Basis (2012 Biomethane Application). The 2012 Biomethane Application sought, among other things, approval to maintain the cost recovery mechanisms described above. However, as part of its Decision on the 2012 Biomethane Application, the BCUC determined that the pipe connecting the upgrader (interconnection costs) was outside the traditional natural gas distribution utility configuration, and therefore part of the cost to acquire supply.[9] The BCUC stated:

> Therefore, the Panel finds that the cost of biomethane metering interconnection facilities are more appropriately considered part of the cost of supply. Accordingly, they should be allocated to the Biomethane Program.[10]

Further, the Panel directed that *"all interconnection and Biomethane Program Costs are to be recorded in the BVA along with the cost of supply."*[11]

The above determinations changed the recovery of interconnection costs from all customers to only Biomethane customers.

Following the Decision on the 2012 Biomethane Application, FEI filed a letter dated February 5, 2014 requesting, among other things, clarification on recovery of interconnection facility costs for projects approved under the pilot program. Specifically, FEI asked if the cost allocation was

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8 Order G-194-10, Decision page 51
9 Order G-210-13, Decision page 52
10 Order G-210-13, Decision page 53
11 Order G-210-13, Decision page 65

applicable only to new biomethane supply projects after the decision. The BCUC responded that this was the correct interpretation.

> Commission Panel confirms that, as such, the interconnection facility cost allocation methodology for the Pilot Program as approved in Commission Order G-194-10 applies to the costs associated with the interconnection facilities for the seven projects listed above.[12]

As a result, the cost of the interconnection facilities of the seven referenced projects continued to be recovered through delivery charges from all customers, while all new interconnection costs were accounted for in the BVA and recovered from Biomethane customers.

The seven projects approved under the pilot program, and referred to in the Decision on the 2012 Biomethane Application are the following:

1. Fraser Valley Biogas Ltd. (originally Catalyst Power Inc.) project interconnection expenditures approved December 14, 2010 via Order G-194-10;
2. Salmon Arm Landfill (partnering with the Columbia Shuswap Regional District) project interconnection expenditures approved December 14, 2010 via Order G-194-10;
3. City of Kelowna Landfill project interconnection expenditures accepted April12, 2012 via Order G-44-12 and Reasons for Decision in the FortisBC Energy Utilities 2012-2013 Revenue Requirements Application;
4. Seabreeze Farm Ltd. project interconnection capital expenditure accepted May 14, 2013 via Order G-79-13;
5. Dicklands Farms project interconnection capital expenditures accepted May 14, 2013 via Order G-79-13;
6. EarthRenu Energy Corp. project interconnection expenditure accepted May 14, 2013 via Order G-79-13; and
7. Greater Vancouver Sewerage and Drainage District project interconnection capital expenditures accepted October 24, 2013 via Order G-175-13.

On August 28, 2015 FEI filed its Application for Approval of Biomethane Energy Recovery Charge Rate Methodology (BERC Rate Methodology Application). The BERC Rate Methodology Application sought and received approval to set the price of biomethane at a premium above FEI's conventional natural gas costs instead of being set based on biomethane production and purchase costs. To allow for the recovery of any biomethane costs not recovered through biomethane sales, FEI sought approval to amortize the forecast December 31 residual balance in the BVA, net of the transfer of unsold inventory and remaining supply

[12] Letter L-10-14, page 2

costs, through the delivery rates of all non-bypass customers effective January 1 of the subsequent year. In Order G-133-16, the BCUC approved the proposal, and determined that the biomethane costs should be recovered through a rate rider, as follows:

> In order to provide the transparency directed in the 2013 Decision the Panel directs that the recovery of the BVA balance be through a rate rider from FEI's non-bypass customers, effective January 1st of the subsequent year (BVA Rate Rider).[13]

1.3 *PROPOSAL – INTERCONNECTION COSTS*

As described in the regulatory history above, the cost of service associated with the seven interconnection projects approved during the pilot period are currently recovered from all non-bypass customers through FEI's delivery rates. FEI proposes to instead account for the cost of service for the seven projects in the BVA, so that they are treated in the same manner as all other projects.

From an accounting efficiency perspective, this is advantageous as all biomethane costs will be accounted for in the BVA so that FEI will not be required to separate the cost of the seven interconnects from FEI's other biomethane related interconnection cost. This will also make the reporting of these costs simpler in FEI's filings with the BCUC.

Flowing these seven interconnection costs through the BVA will also improve transparency, as all biomethane-related costs will be included in the BVA. This is consistent with the transparency principles that the BCUC discusses in Order G-210-13[14].

For these reasons, FEI proposes that the interconnection costs for FEI's seven interconnection facilities identified in the 2010 Biomethane Application be accounted for in the BVA consistent with all other interconnection costs under the Biomethane program.

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[13] Order G-133-16, Decision page 45
[14] Order G-210-13, Decision page 35

Appendix C

PROPOSED MULTI-YEAR RATE PLAN

Appendix C1

FORTISBC PRE-2014 PBR EXPERIENCE

1. FORTISBC PRE-2014 PBR EXPERIENCE

Both FEI and FBC have had a long history with multi-year rate plans, and specifically performance-based rate-setting, going back to the 1990s. In this section, previous and existing generations of PBR plans employed by FortisBC are studied. Understanding FEI's and FBC's experiences with PBR plans will provide additional insight into FortisBC's perspective in developing this Application as the proposed MRP builds on the successes and lessons learned from these plans, incorporating some similar elements with adjustments where appropriate. FortisBC's experience with the 2014-2019 PBR Plan is discussed in the Section B-2 of the Application. This appendix will provide further detail regarding FEI's and FBC's pre-2014 MRPs.

1.1 *FEI EXPERIENCE*

1.1.1 FEI 1998 PBR Plan

The 1998 PBR plan was approved on July 23, 1997 by Order G-85-97. The plan was originally set for three years but was later extended to 2001. This was the first generation of FEI's (then BC Gas) PBR plan that covered both capital and O&M expenditures[1]. A brief summary of the main features of the 1998 PBR plan is provided in the Table A:C1-1 below.

Table A:C1-1: Main Features of FEI's 1998 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		Initially three years (1998-2000) subsequently extended to 2001
Formula	O&M	$O\&M_t = [\ O\&M_{t-1} * (1+G-X) * (1+I)\ ]$ + Costs of defined required activities G = Forecast percentage growth in the average number of customers
	Capital	<u>Type I: Unit cost approach</u> Allowed Unit Cost $_t$ = Unit Cost $_{t-1}$ * (1+I-X) Allowed Cost $_t$ = Allowed Unit Cost $_t$ * Units Forecast $_t$ <u>Type II: Aggregate cost approach</u> Allowed Cost $_t$ = Cost $_{t-1}$ * (1+I-X)
I-Factor		CPI-BC
X-Factor		Various values set as part of the NSP
Y-Factor		Yes, included deferral accounts for items such as interest, DSM expenses, tax variances and RSAM.
Z-Factor		Yes, available for costs caused by exogenous factors, no materiality threshold
ESM		Yes, 50:50 sharing of variances between authorized and actual earnings net of specific incentive programs which were considered as non-utility earnings.

[1] A formula-based approach to setting O&M was first adopted in FEI's 1994-1995 settlement and refined in the 1996-1997 settlement.

Item	Description
ECM	Available through the capital efficiency mechanism
Incremental Capital	Available through CPCN process, no materiality threshold was defined.
SQI	Yes, Included five metrics

As can be seen, the 1998 PBR plan included two types of capital formulas. The first and more widely used unit cost approach was employed to calculate the allowed costs for capital cost categories such as mains, services, meters and system improvements and reinforcements. The unit costs for some of these categories such as mains and services were calculated based on regional unit costs (i.e. interior unit cost and lower mainland unit cost) to account for the differences in unit cost in different regions of FEI's service territory. The remaining capital costs not suitable for the unit cost approach were calculated using the aggregate formula presented in Table XX above. Further to the formula driven costs, the utility was able to apply for incremental capital funding using the CPCN process. The negotiated settlement specified that any efficiency gained as a results of these projects could also be used to achieve the targeted O&M productivity level.

The 1998 PBR plan also included a "capital efficiency mechanism". Under this mechanism, the variance between actual unit costs and allowed unit cost was multiplied by the actual number of units. This amount would then be added or subtracted from the utility rate base. The capital efficiency incentive adjustment to rate base would phase out over three years.

1.1.2 FEI 2004 PBR Plan

The 2004 PBR plan was originally approved by Order G-51-03 for a four year period (2004-2007), and subsequently extended for two years, ending in 2009. Table A:C1-2 below presents the main elements of 2004 PBR plan. This plan maintained a few features of the 1998 plan (similar ESM, deferral accounts, use of CPCN process for incremental capital funding, inflation factor, etc.) while introducing changes to other elements (such as capital formulas). Table A:C1-2 below provides a brief summary of the main features of FEI's 2004 PBR plan.

Table A:C1-2: Main Features of FEI's 2004 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		Initially four years (2004-2007) subsequently extended to 2009
Formula	O&M	$O\&M_t = [\, O\&M_{t-1} * (1+G) * (1+I - X) \,]$ G = Forecast percentage growth in the average number of customers
	Capital	$\text{Allowed Unit Cost}_t = \text{Unit Cost}_{t-1} * (1+I-X)$ $\text{Allowed Cost}_t = \text{Allowed Unit Cost}_t * \text{Units Forecast}_t$ Two formulas: (i) growth capital; (ii) Other capital
I-Factor		CPI-BC

Item	Description
X-Factor	Various percentage of inflation factor determined as part of the NSP
Y-Factor	Yes, included deferral accounts for items such as debt interest, DSM expenses, tax variances, pension and RSAM.
Z-Factor	Yes, available for costs caused by exogenous factors, no materiality threshold
ESM	Yes, 50:50 sharing of variances between the allowed and actual ROE (net of GSMIP, DSM Incentive, load building and incentives for partially controllable items) using the common equity component of the actual rate base.
Safeguard Mechanism	Any party could request a review process if the achieved ROE after ESM varies from the approved ROE by 150 bps in any year of the plan
ECM	Available through the phase-out of capital benefits
Incremental Capital	Available through CPCN process, Materiality threshold of $5 million
SQI	Yes, Included six SQIs and two directional indicators
Other incentives	Included separate incentive mechanism (not subject to ESM) such as incentives for partially controllable costs (municipal taxes) and load building incentives

As indicated in the table above, the 2004 PBR plan included both capital expenditures and O&M expenditures. For O&M expenses, the approved 2003 O&M was used as the base, and then escalated by inflation, a productivity factor and a customer growth factor. Customer growth was expressed as the change in the average number of customers from one year to the next. Similar to O&M, the capital expenditures approved in the 2003 RRA were used as the base, and then escalated for inflation and a productivity factor. The capital expenditures were separated into two categories - growth capital (customer addition driven capital expenditures such as capital needed to install service lines) and other capital (where the average number of customer was used as the cost driver). The base capital expenditures were not rebased during the term of the PBR. However, similar to the treatment for O&M, there was a prospective true-up in the formula capital expenditures for actual customer growth. Similar to 1998 PBR plan, CPCN additions were excluded from the capital formula, and instead addressed in separate regulatory processes.

The 2004 PBR plan also included an efficiency carry-over mechanism for capital-related costs. It involved determining the difference between the formulaic and actual capital expenditures over the term of the PBR, and then, rather than full rebasing right away, the Company received 2/3 of its 50 percent share in the first year following the expiry of the plan, and 1/3 of its 50 percent share in the next year.

1.2 FBC EXPERIENCE

1.2.1 FBC 1996 PBR Plan

In 1996, FBC (then West Kootenay Power), as part of its 1996 Revenue Requirements Application, received BCUC approval by Order G-73-96 to enter into a PBR plan to replace cost of service regulation. The plan consisted of 'targeted' cost categories with cost drivers, base costs, escalators, productivity improvement factors and a sharing mechanism. In addition to cost categories, performance standards including customer satisfaction and system reliability were included as part of the PBR plan, and were subject to annual review to confirm that service quality was being maintained throughout the term.

The PBR plan was originally approved for 1996-1998, but the Negotiated Settlement contemplated a potential continuation of the PBR Plan. A one-year extension was approved for 1999 by Order G-123-98; in addition the Settlement Agreement approved by that order required the Company to file a multi-year rate-making proposal to commence in 2000. The Company's 2000-2002 Revenue Requirements Application, extending the plan and amending the incentive mechanism, was approved by Order G-134-99. Subsequent one-year extensions to the plan were approved for 2003 by Order G-10-03 and for 2004 by Order G-38-04. Certain of the mechanisms included as part of the original PBR plan were modified in subsequent extensions. These modifications included the introduction of a power purchase variance mechanism and market incentive mechanism, as well as the exclusion of capitalized overhead from the sharing mechanism.

Table A:C1-3: Main Features of FBC's 1996-2004 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		9 years (1996-2004), Approved for three years (1996-1998) and extended for 1999, 2000-2002, 2003 and 2004.
Formula	O&M	$O\&M_t = [(O\&M/customer)_{t-1} * [1 + (I-X)]] * (customer_t)$ Forecast percentage growth in the average number of customers
	Capital	Four categories of capital expenditures escalated by applicable drivers including customer growth and system peak load
I-Factor		CPI-BC (O&M, General Plant capital) or CPI-Canada (all other capital)
X-Factor		Various percentages for each year determined as part of the initial NSP
Y-Factor		Yes, Items such as pension expense, certain lease costs were excluded from the formulas and treated as flow-through. Other items such as DSM expenses were also treated outside the formula. Non-routine capital approved by project.
Z-Factor		Yes, For extraordinary costs outside of the "steady state" operations as determined by O&M formula. No materiality threshold.
ESM		Symmetric 50:50 sharing for variance between allowed and actual O&M expense, other income, income taxes and interest volume. Incentives for power purchase expense included from 2000 - 2004.

Item	Description
Safeguard Mechanisms	Other than ESM no financial safeguard provided. The 1999-2000 application included a review of the plan and the extensions to the plan were contingent on the mutual agreement of parties.
SQI	A number of performance standards were established to provide an overall assessment of the FBC's performance

1.2.2 FBC 2007 PBR Plan

FBC's subsequent PBR plan commenced in 2007 pursuant to an approved Negotiated Settlement Agreement (Order G-58-06) and remained in effect (after an approved three-year extension) until 2011.

The 2007 Plan was based on the previous PBR plan in key aspects, and included the continued use of cost and growth escalators and a productivity factor. A key difference in the 2007 PBR plan was the exclusion of capital expenditures as part of the PBR plan. Instead, capital expenditures were to be approved as part of a separate annual filing or by way of filing CPCN applications for major projects. As well, a symmetric earnings sharing mechanism replaced the previously-existing line-by-line review used to determine the level of any incentive sharing between the Company and its customers. A brief summary of the main features of FBC's 2007 PBR plan is provided in Table A:C1-4 below.

Table A:C1-4: Main Features of FBC's 2007 PBR Plan

Item		Description
Process		Negotiated Settlement
Term		5 years (2007-2011), Approved for two years and extended to the end of 2011.
Formula	O&M	$O\&M_{t} = [(O\&M/customer)_{t-1} * [1 + (I-X)]] *(customer_{t})$ Forecast percentage growth in the average number of customers.
	Capital	Not subject to formula. Set based on separate capital expenditure schedule filings or CPCN applications.
I-Factor		CPI-BC
X-Factor		Various percentages for each year determined as part of the initial NSP.
Y-Factor		Yes, Items such as pension and post-retirement benefits and office lease costs were excluded from the formulas. Other items such as DSM expenses were also treated outside the formula.
Z-Factor		Yes, For extraordinary costs outside of the "steady state" operations as determined by O&M formula. No materiality threshold.
ESM		Symmetric 50:50 sharing for variance between the allowed and actual earnings up to 200 bps. Differences greater than 200 bps to be placed in a deferral account for review and disposition in annual review.

Item	Description
Safeguard Mechanisms	Other than ESM no financial safeguard provided. However the 2008 annual review included a review of PBR plan and the extension to the plan were contingent on the mutual agreement of parties.
SQI	A number of performance standards with associated targets were established to provide an overall assessment of the FBC's performance

As indicated, the O&M formula was based on a unit cost approach where the base O&M unit cost is escalated by an I-X index and the result is multiplied by the average number of customers to calculate the allowed O&M expense in each year. The inflation index and growth factor in the formula were forecast with no true-up for actual amounts. Capitalized overheads was also determined by formula, at 20% of Gross O&M Expense.

The 2007 PBR plan further expanded the number of service quality indicators to improve the measurement of customers' satisfaction with both the quality and reliability of service as well as the convenience of customers' routine interactions with FBC. Under this negotiated incentive framework, failure to meet one (or more) targets did not necessarily constitute unacceptable performance. Rather BCUC would take into account the reasons given by the Company on why certain performance targets were not met and why the Company should be entitled to an incentive payment.

Appendix C2

BENCHMARKING REPORTS

Benchmarking Study

Prepared for:

FortisBC Energy Inc.

February 11, 2019

Prepared by:

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TABLE OF CONTENTS

I. <u>INTRODUCTION</u>

FortisBC Energy Inc. ("FEI," or the "Company"), retained Concentric Advisors, ULC ("Concentric") in February 2018 to conduct a benchmarking study on utility efficiency (the "Study"). The Study encompassed a review of the Company on a stand-alone basis and a comparison of the Company to Canadian and U.S. natural gas utilities.[1] For the comparative analysis, the Study focused on a series of metrics designed to examine the relative efficiency of the Company in terms of its operations and maintenance ("O&M") expense profile, capital investment, reliability, customer service, and other factors.

II. <u>LIMITATIONS AND CAVEATS</u>

The following are the limitations and caveats associated with the Study:

- Concentric did not audit or otherwise independently validate the data provided by FEI or other Canadian utilities. While our analysis included a careful review of the data to identify inconsistencies, as well as multiple rounds of communications with the Company and its peers through which Concentric was able to resolve data issues and place the companies on a comparable basis, we relied on FEI and the companies in our survey to provide complete and accurate data that was consistent with the benchmarking categories.
- Because the majority of the data provided by the Canadian peer companies was not otherwise publicly available, the Canadian utilities provided their information on a confidential basis. Concentric listed the companies in Figure 1, below, but otherwise masked the names of the utilities in our analyses and figures to preserve that confidentiality. Further, we did not shared peer group-specific details or data (other than those disclosed in this report) with FEI.
- Accounting policies and procedures can impact utility companies' reported financial results, particularly when those results are used for comparative purposes. For instance, factors that can impact relative expense levels include the capitalization policies, capitalization rates, and cost allocation practices that a utility uses.[2] The actual amount of dollars that are split between expense and capital projects will also depend on the overall level of capital expenditures incurred in a given year. In other words, the relative level of each company's operations,

[1] Concentric also conducted an electric utility study documented in a separate report.

[2] FEI, for instance, reduced its capitalization rate starting in 2014, going from 14% to 12%. All else being equal, that would result in greater amounts of administrative and general ("A&G") expenses resulting from the reduced capitalization rate, with lower amounts of capital expenditures.

maintenance, and administrative ("OM&A") and capital expenditures depends on: (a) the level of capital expenditures it incurs; and (b) the rate at which it allocates labour and overhead costs to capital projects. As such, normalizing for those differences between companies would be extremely difficult, particularly when assessing relative expense levels over time.[3] The use of peer groups is designed to mitigate those risks in two ways. First, use of companies in the same industry (*i.e.*, regulated utilities) is intended to capture, at a high level, companies with similar capital expenditure needs and capitalization procedures. Second, while each company may apply different capitalization ratios and have differing levels of capital expenditures within the bounds of industry norms, the use of multiple companies in the peer group is intended to mute the impact that any one company's policies and procedures can have on the overall results. It is important to recognize, however, that such differences may exist, and could impact the financial results of any one company when viewed in isolation. Further to this point, Concentric analyzed both expense and net plant figures to provide a more complete review of FEI's financial position and cost structure relative to the peer group companies.

- Financial data are expressed in own-country terms, without adjustment to account for fluctuating exchange rate differentials. For that reason, the U.S. data are presented separately from the Canadian data in each figure in the Study and are excluded from the Canadian peer group median and quartile calculations. That ensures that differently-denominated financial results are not factored together in the benchmarking results. Over time, sustained exchange rate differentials between Canada and the U.S. can contribute to differences between the Canadian companies (including FEI) and the U.S. companies, particularly in more recent years, as the exchange rate difference was more pronounced.[4] Concentric did not attempt to adjust for exchange rate differences, as it would require the introduction of a cross-border index (such as the World Bank's purchase power parity index), and such an index would have to consider capital investments made over many years and is beyond the scope of this study.

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3 Concentric also inquired of the Canadian peer group companies: (a) how their overhead capitalization rates changed over the period studied; and (b) whether they had any significant changes in accounting policies over the period studied. Unsurprisingly, for those companies that responded, there was a diversity of practice in terms of the method of allocating A&G expenses to capital projects, as well as the rates at which such allocations are done.

4 Specifically, the U.S. dollar to Canadian dollar exchange rate was close to parity in the 2012 to 2013 timeframe, but the U.S. dollar began to strengthen in 2014. For 2015 through 2017, the exchange rate was consistently at or above 1.00 U.S. dollars to 1.20 Canadian dollars (*see*, *e.g.*, https://www.bloomberg.com/quote/USDCAD:CUR, accessed July 18, 2018).

III. DESCRIPTION OF FEI

FEI is the largest distributor of natural gas in British Columbia ("BC"), serving approximately one million residential, commercial and industrial, and transportation customers in more than 135 communities. Major areas served by FEI are the Mainland, Vancouver Island and Whistler regions of BC. FEI provides transmission and distribution services to its customers and obtains natural gas supplies on behalf of most residential, commercial and industrial customers.

FEI is an indirect wholly-owned subsidiary of Fortis Inc.

IV. INDUSTRY BENCHMARKING METHODOLOGY

A. Overview

Benchmarking is a commonly employed analytical technique used across a wide variety of industries to compare a company's performance against an industry group, which serves as the benchmark. Comparator companies are typically chosen from within the same industry, and screens are typically applied to narrow the field to companies with reasonably comparable operations. Company service offerings, size, geography, age of assets, *etc.*, may be used as screens, or as variables used to explain performance differences. On a given performance attribute (*e.g.*, O&M expenditures per unit of output), certain explanatory measures (*e.g.*, average, median, quartile, *etc.*) determine average and best of class performance, and help to identify performance gaps against those standards. Benchmarking is often conducted for a limited number of time periods, or even a single year.

The benefits of benchmarking are its intuitive appeal and the ability to compare against companies chosen from within the same industry. Even though no two companies face identical operating circumstances, benchmarking provides a view into industry performance and provides perspective for regulators and stakeholders. Limitations of benchmarking include its inability to quantify causal relationships between operating circumstances and costs, and between inputs and outputs.[5] Detailed data across companies beyond top line revenue and cost categories can also be difficult to glean from public sources. Further, the standard benchmarking comparison is a relative one, and therefore does

[5] Econometric benchmarking can be employed where multi-company "panel" data is available, and the objective of the study is to identify the effects of causal factors.

not offer insights into optimal performance (sometimes referred to as the "efficient frontier") in an absolute sense.[6]

B. Determination of Industry Peer Groups

The industry peer groups used in the Study were selected according to criteria designed to produce peer groups with operating circumstances similar to FEI. The criteria, which are listed below, were also determined to allow for a peer group size that would provide a sufficiently broad perspective for industry comparisons.

- Operations: The companies in the FEI peer group are natural gas transmission and distribution utilities, as well as distribution-only utilities. Because the peer group companies provide similar services, it is reasonable to assume that they will broadly have similar business functions within their companies in order to provide those services, thus providing a basis upon which to compare the financial and non-financial metrics of FEI.
- Geography: The Study includes Canadian natural gas distribution utilities and utilities in the Pacific Northwest U.S. region.
- Rate Regulated: The Study includes investor-owned natural gas utilities governed by a utility commission.

Those criteria resulted in a group of five Canadian and eight Pacific Northwest U.S. natural gas utilities for the FEI peer group. Concentric also analyzed whether there are appropriate subsets of utilities that can be used as a proxy for FEI. Our conclusion, however, was that further consolidation of the peer groups was unnecessary. The reasons for that are twofold. First, as described further below, Concentric used peer group medians and quartiles for the purposes of benchmarking FEI. In a broad sense, therefore, the Study already amalgamated the companies in the peer groups. Second, Concentric had concerns with benchmarking FEI against an amalgamated proxy made up itself of only a few companies. The specific concern was one of sample size limitation, and the amalgamated benchmark being skewed by the anomalous results of one or two of the component companies.

[6] Data Envelopment Analysis ("DEA") can be employed where an objective of the benchmarking is to quantify the theoretical optimum.

A complete list of the Canadian and Pacific Northwest U.S. natural gas utilities included in the industry peer groups is provided in Figure 1.[7]

Figure 1: Peer Group Canadian and Pacific Northwest U.S. Natural Gas Utilities

No.	Company Name	Ultimate Parent Company Name	State(s)/ Province of Operation
	Canadian Natural Gas Utilities		
1	ATCO Gas Distribution	ATCO Ltd.	Alberta
2	Enbridge Gas Distribution	Enbridge Inc.	Ontario
3	Energir	Energir Inc.	Quebec
4	Pacific Northern Gas	AltaGas Ltd.	British Columbia
5	Union Gas	Enbridge Inc.	Ontario
	Pacific Northwest U.S. Natural Gas Utilities		
1	Avista Corporation – Idaho	Avista Corp.[8]	Idaho
2	Avista Corporation – Oregon	Avista Corp.	Oregon
3	Avista Corporation – Washington	Avista Corp.	Washington
4	Cascade Natural Gas Corporation – Oregon	MDU Resources Group, Inc.	Oregon
5	Cascade Natural Gas Corporation – Washington	MDU Resources Group, Inc.	Washington
6	Intermountain Gas Company – Idaho	MDU Resources Group, Inc.	Idaho
7	Northwest Natural Gas Company – Oregon and Washington	NW Natural	Oregon, Washington
8	Puget Sound Energy – Washington	Puget Sound Energy	Washington

C. Benchmarking Metrics

The Study focused on the following financial and non-financial benchmarking metrics. These metrics measure the utilities' financial efficiency, reliability, and customer service performance. These metrics were chosen in consultation between the Company and stakeholders. In Concentric's opinion, this set of metrics provides for a reasonably comprehensive overview of FEI's relative performance on both a financial and a non-financial basis.

Figure 2: Description of Benchmarking Metrics

Metric	Description
OM&A expenses per customer, unit of throughput, employee, and kilometre of gas mains	OM&A per unit (*e.g.*, customers, throughput, employees, kilometre of pipe, *etc.*) measures a company's financial efficiency in terms of the level of expenses it incurs per unit. In a capital-intensive industry, such as the utility industry, OM&A should also be considered together with fixed assets (*i.e.*, net plant), as a company's capitalization policy will impact the amount of costs that are recorded to OM&A versus capital.

7 In total, Concentric requested data from eight natural gas Canadian utilities, and received data from five of those companies.

8 On July 19, 2017, Hydro One announced that it was acquiring Avista Corp. As of the date of this report, however, that transaction had not closed.

Metric	Description
Net plant per customer, employee, and kilometre of gas mains	Net plant per unit (*e.g.*, customers, employees, kilometre of pipe, *etc.*) measures a company's financial efficiency in terms of its level of fixed assets. As described above, net plant per unit should be considered together with OM&A to provide a more complete view of a company's cost structure.
Energy delivered per customer	Energy delivered per customer provides descriptive information regarding a company's customer base and usage characteristics.
Energy delivered per employee	Energy delivered per employee provides information regarding the efficiency of a utility in providing service.
Employees per customer	Employees per customer provides further information regarding the efficiency of a utility in providing service.
Administrative and General ("A&G") expense per customer and volume	A&G per unit (*e.g.*, customers, output, *etc.*) measures the efficiency of a company's administrative and back office functions. In a benchmarking analysis, A&G should be considered together with the company's overall expense levels (*i.e.*, OM&A), because different companies may have different policies regarding the recording and reporting of A&G costs such as labour costs and benefits. Some companies may record those costs as A&G, while others may use overhead loading factors to reclassify those costs to operations.
Customer care costs per customer	Customer care costs per unit provide information both about the overall scope of a company's customer care function, as well as the efficiency of that function.
Financing costs per customer	Financing costs per customer provide information regarding a company's cost of capital. In a capital-intensive industry, such as the utility industry, financing costs will tend to correlate with overall fixed asset/net plant figures.
Emergency response time	This measure is calculated as the percent of calls responded to within one hour and measures the responsive efficiency of the utility.
Telephone response and abandonment rates	Telephone service factor ("TSF") – emergency and non-emergency, first contact resolution ("FCR"), and telephone abandonment rate all measure customer service via call centers. TSF is the number of calls answered within 30 seconds divided by the number of calls received. FCR is the percent of customers who achieved call resolution within one call. The telephone abandonment rate is equal to the total number of abandoned calls divided by the total number of answered calls plus abandoned calls.

Metric	Description
Demand side management ("DSM") expenditures	DSM expenditures per customer measures each company's expenditures on DSM programs, both with incentives and without incentives. Non-incentive expenditures include indirect costs associated with the DSM program (*e.g.*, program administration, communication and outreach, research and evaluation of the program, *etc.*). The level of DSM expenditures is dependent on the availability of regulatory mechanisms for cost recovery and the utility's efficiency in deploying these programs.
Greenhouse gas emissions	This metric measures direct greenhouse gas ("GHG") emissions by natural gas utilities.

D. Data Sources

The Study is based on data that was compiled from publicly available sources and commercially available databases for the Pacific Northwest U.S. utilities. For the Canadian companies, there is insufficient publicly available information that is available on a consistent basis. Therefore, Concentric sent data surveys to Canadian utilities requesting the data necessary for the Study. In total, Concentric requested data from eight natural gas Canadian utilities, and received data from five of those companies. Because the majority of the data that was provided was not otherwise publicly available, the Canadian utilities provided their information on a confidential basis. Concentric necessarily had access to the names and company-specific data for each utility, but FEI did not have such access (except as provided herein). As such, the names of the utilities are not linked with the results in the Study so as to preserve that confidentiality.

FEI's data is primarily based on data provided by FEI for 2012 through 2017. Data provided by the Company includes the underlying financial and operational data necessary to calculate the benchmarking metrics (*i.e.*, O&M expenses, net plant, customers, employees, pipe lengths, and volumes,[9] as well as the reliability and customer service metrics).

1. Canadian Peer Group

Because the Canadian data was not available as one data set or from consistent, publicly-filed financial statements, Concentric took steps to ensure that the data collected through our survey process was consistently-presented and provided a reasonable and adequate basis upon which to compare FEI.

[9] Concentric used actual volumes in the Study, not weather normalized volumes. The main reason for this is that, while utilities normalize volumes for weather for ratemaking purposes, they do not typically normalize expenses for weather.

Those steps included: (1) sending to each survey respondent a template to be completed that was organized consistently with the benchmarking metrics, and with descriptions of each metric, so as to limit differences in interpretation; (2) after receiving responses, carefully reviewing the data for anomalous results and inconsistencies; (3) through an iterative process, working with each surveyed company through a series of follow-up communications to resolve questions and data classification/presentation issues. The survey template is provided in Appendix A to the Study, and a more detailed description of the data gathering and validation process is provided in Appendix B.

For GHG benchmarking, Concentric relied on Environment and Climate Change Canada's Greenhouse Gas Emissions Reporting Program ("GHGRP").

2. Pacific Northwest U.S. Peer Group

For the Study, Concentric primarily relied on data compiled from annual reports filed by the individual operating utilities with their federal or state regulatory commissions.[10] Once collected, the database of data was checked for completeness and consistency. Data was gathered and presented at the state level, not the holding company level. Concentric also relied on the data contained within the U.S. Energy Information Administration's Form 176 filings. For GHG benchmarking, Concentric relied on the U.S. Environment Protection Agency's GHGRP.

V. INDUSTRY BENCHMARKING RESULTS

A. Overview

This section presents the results of the benchmarking analyses. First, an overview of descriptive metrics (*e.g.*, percentage of plant by function and number of customers) is provided for FEI and each of the peer group companies. Second, an analysis of FEI's performance on a stand-alone basis is provided. Third, a comparison of FEI's relative performance to that of the peer groups is provided.

FEI's performance compared to other utilities is heavily reliant on the composition of the proxy group. As such, it is important to focus not only on those groupings of companies that are most comparable to FEI, but also on those data that provide a comparison of utilities on a similar basis. As discussed herein, Concentric focused on those cost segments (*i.e.*, distribution costs) that both maximized the

[10] Concentric primarily relied on data from the annual reports as provided through the SNLxL database.

number of peer companies included in the analysis, and put the peer companies on as equal a footing as possible.

For those metrics where sufficient peer group data was available, each benchmarking figure presents five main data points: (1) FEI's result for each metric, per year; (2) the Canadian peer group median (including FEI) result, per year; (3) the Canadian peer group median (excluding FEI) result, per year; (4) a shaded region that provides the range between the first and third quartile performance in the Canadian peer group (including FEI) (denoted as "Canadian Q1-Q3" in each figure); and (5) the Pacific Northwest U.S. peer group median, per year. Because Concentric is benchmarking costs, first quartile performance represents the lower quartile. For those metrics for which insufficient peer group data was available (*i.e.*, there was data available from less than five peer group companies, and thus quartiles would be less meaningful), the figures do not provide the shaded region with the range between the first and third quartile performance for the Canadian companies.

B. Descriptive Metrics

As noted previously, FEI's performance is compared to a peer group of five Canadian and eight Pacific Northwest U.S. natural gas utilities that were chosen based on a number of selection criteria designed to reflect FEI's operating profile and provide a broad perspective for industry comparisons. In order to provide context and background on the peer group, the following sections compare FEI's operational profile to the peer group.

1. Operational Profile

The figure below provides the operational profile of the companies in the peer group in terms of the percentage of net plant dedicated to distribution, transmission, storage, and other operations.

Figure 3: Natural Gas Company Functional Mix

Company	Distribution	Transmission	Storage	Other
FEI	**58%**	**28%**	**5%**	**9%**
Company A[1]	N/A	N/A	N/A	N/A
Company B[1]	N/A	N/A	N/A	N/A
Company C	43%	51%	0%	6%
Company D	45%	33%	13%	9%

Company	Distribution	Transmission	Storage	Other
Company E	63%	6%	8%	23%
Company F	65%	13%	5%	17%
Company G	84%	0%	0%	16%
Company H	87%	0%	0%	13%
Company I	89%	0%	0%	11%
Company J	92%	0%	4%	4%
Company K	94%	1%	1%	4%
Company L	97%	0%	2%	2%
Company M	97%	0%	0%	3%
Average	76%	11%	3%	10%

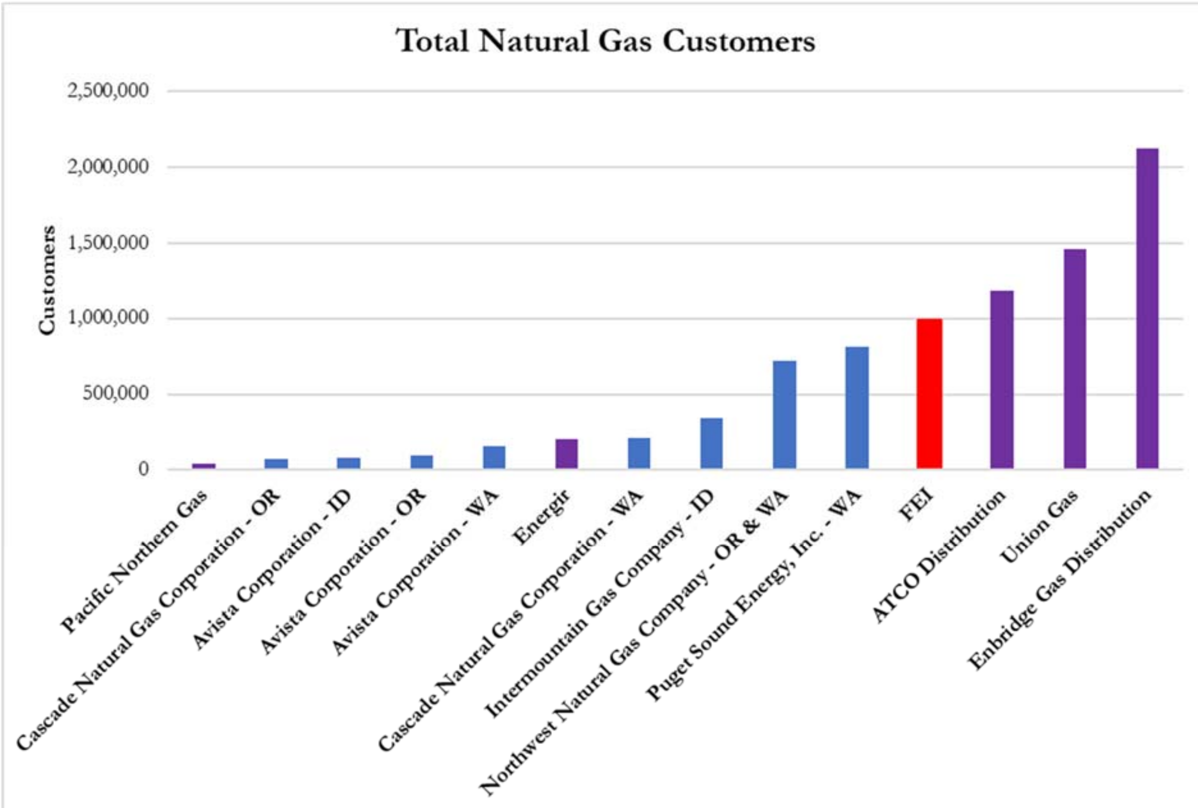
[1] Net plant was not reported at the functional level for these companies.

As shown in the figure above, the companies in the peer group have different mixes of functions within their operational profiles. This can lead to skewed results if certain companies have a greater proportion of their operations in traditionally higher cost functions or functions that are more subject to cost variation. Concentric controlled for that risk in the Study by focusing on the distribution-only segment of the peer group companies (plus total A&G costs), and excluding transmission and storage O&M, from certain of the financial analyses.

2. <u>Customer Profile</u>

As of 2017 (*i.e.*, the last year in the period studied), FEI served approximately one million natural gas customers. In terms of utility size, as measured by number of natural gas customers, FEI is the fourth largest Canadian utility among the peer group and fourth largest overall among the Canadian and Pacific Northwest U.S. peer groups. The average and median number of customers in the natural gas peer group are approximately 605,000 and 274,000, respectively, as compared to FEI's approximately one million customers. The figures below show the total natural gas customers as of the most recent data available for FEI (in red) and each of the natural gas utilities in the peer group (with the Canadian utilities in purple and the Pacific Northwest U.S. utilities in blue). These data suggest that to the extent scale economies are operative, FEI would be expected to be among the most efficient of its gas utility peers.

Figure 4: Peer Group Natural Gas Customers[11]



3. System Throughput

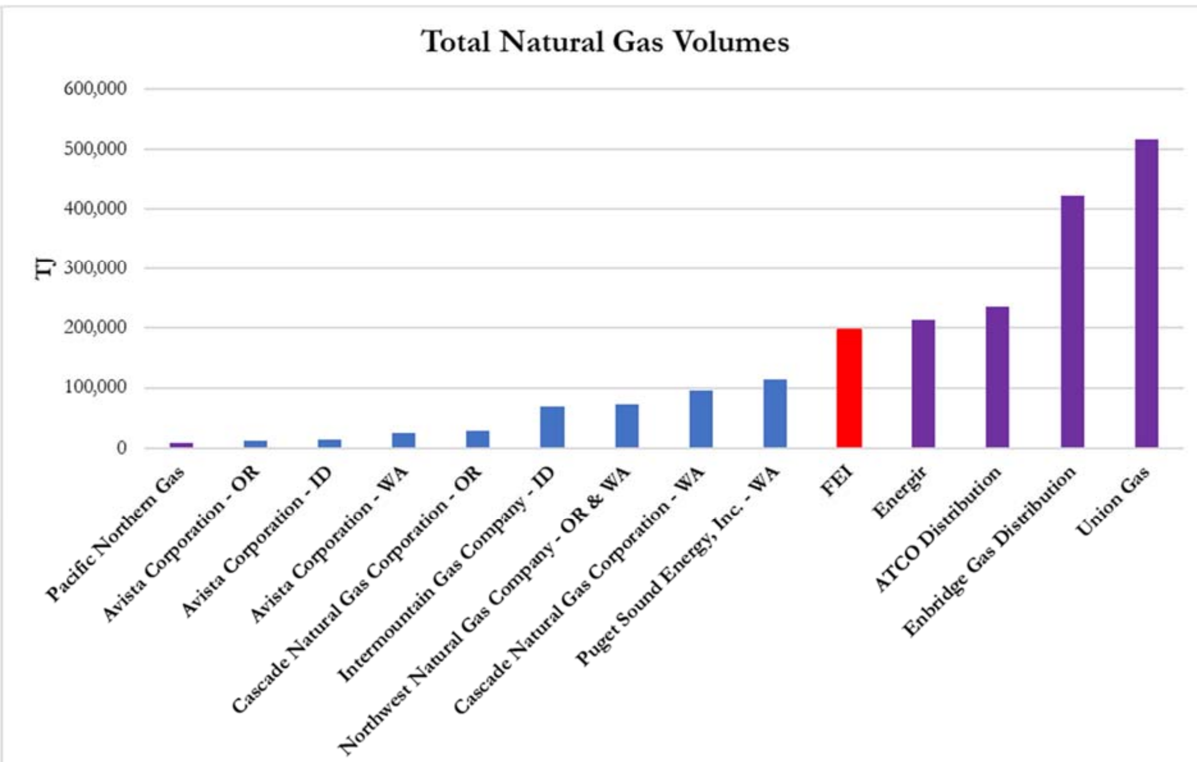
The figures below show the most recently available total natural gas volumes for FEI and each of the natural gas utilities in the peer groups, as well as the volumes sold per customer. As illustrated, FEI is the fifth largest Canadian utility among the peer group and fifth largest overall among the Canadian and Pacific Northwest U.S. peer groups. The average and median volumes in the natural gas group are approximately 145,000 terajoules ("TJ") and 84,000 TJ, respectively, as compared to FEI's approximately 197,000 TJ.

Figure 6 demonstrates that FEI is near the median of the Canadian peer group in terms of volumes per customer, indicating general comparability to the Canadian utilities in the Study in terms of customer profile and usage. FEI does, however, have a high percentage of residential and commercial customers (88% combined in 2017) in its overall customer base, and, as discussed herein, its relative

11 Data is as of 2016, as 2017 data was not yet available for all Pacific Northwest U.S. utilities as of the time of Concentric's analysis.

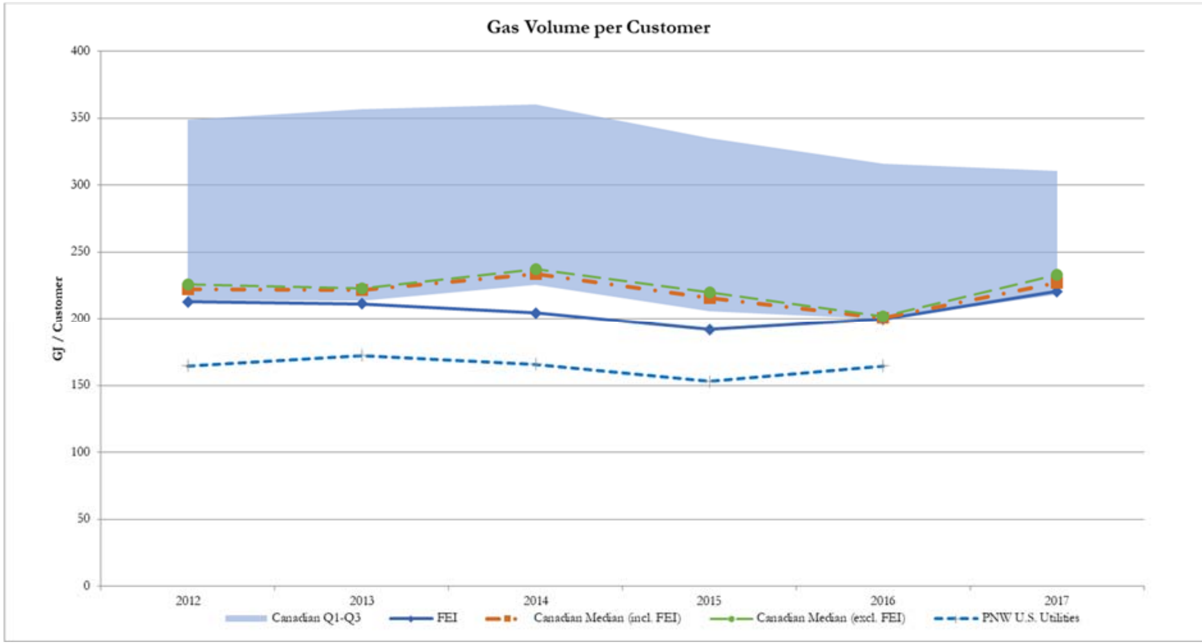
performance compared to the peer groups is more favorable when expressed on a per-customer basis than when expressed on a per-unit-of-volume basis. The wide range in volumes-per-customer results between the second and third quartile, as illustrated by the shaded region in Figures 6, is driven by the composition of the Canadian peer groups' customers, whereby those companies with a higher percentage of commercial and industrial customers (and thus a lower percentage of residential customers) have significantly more volume delivered per customer, and visa-versa. In addition, most of the companies in the Canadian peer group are clustered close to the median, while one company has significantly more volume per customer than the others. That is what drives the median in the figure to be shown as falling close to the bottom of the "Canadian Q1 – Q3" shaded region.

Figure 5: Peer Group Natural Gas Volumes[12]



12 Data is as of 2016, as 2017 data was not yet available for all Pacific Northwest U.S. utilities as of the time of Concentric's analysis.

Figure 6: Gas Delivered per Customer



C. Stand-Alone Financial Analysis

In terms of analyzing FEI's performance on an isolated basis, the Company's OM&A and net plant have increased modestly over the period studied on a nominal basis (five-year compound annual growth rates ("CAGRs") of 0.75% and 1.36%, respectively), and have decreased (in the case of OM&A) or remained flat (in the case of net plant) on a real basis, based on a five-year average annual increase in the Consumer Price Index of 1.39%.[13] The following figures illustrate those trends.

[13] Source: Statistics Canada. Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted.

Figure 7: FEI Total O&M Expense ($000s, nominal)

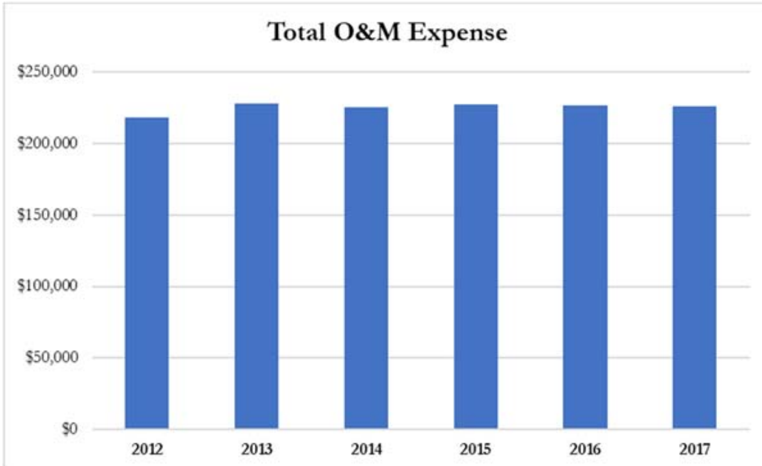
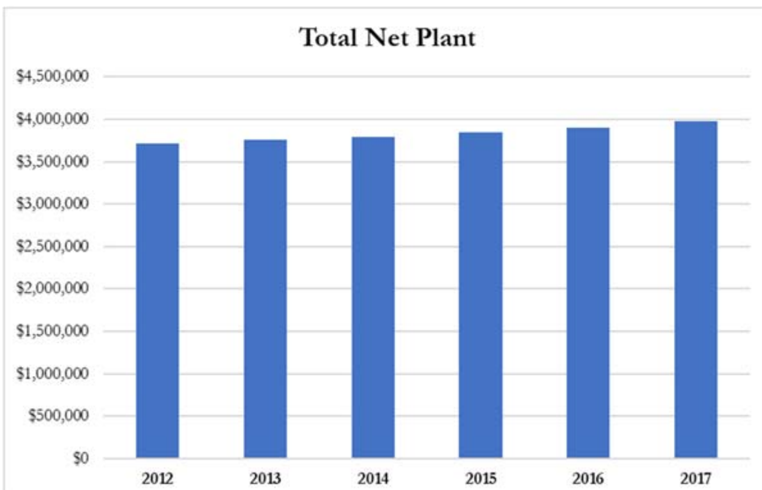


Figure 8: FEI Total Net Plant ($000s, nominal)



D. Benchmarking and Trend Analysis

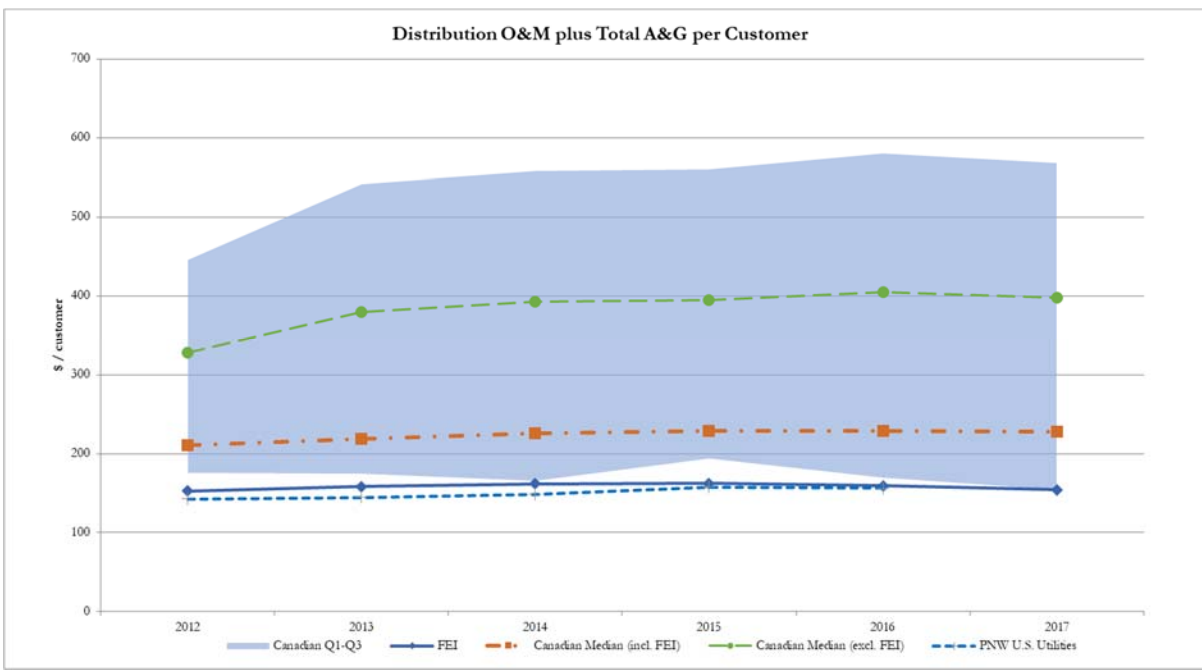
The following sections summarize the results of the benchmarking and trend analysis that compares FEI's performance against the natural gas peer group across a number of financial and operational metrics. FEI's natural gas performance is benchmarked against the Canadian and Pacific Northwest Pacific Northwest U.S. peer groups over the period 2012 through 2017. Certain Pacific Northwest U.S. peer group data, however, was only available through 2016, so Pacific Northwest U.S. data is presented only through that year.

Financial Metrics

For FEI, Concentric's initial observation is that the distribution-only (plus total A&G, excluding customer care)[14] segment provides the most meaningful benchmark, because of significant differences between the scope of peer companies' transmission and storage facilities (as discussed above), as well as differences between the level of customer care services provided across the Canadian utilities. Specifically, the peer group utilities in Alberta do not provide certain customer care services (*e.g.*, billing, collections) to end-use customers. Rather, those functions are provided by retail choice providers. Use of the distribution O&M plus total A&G cost segment also ensures the inclusion of the greatest number of peer group companies, providing for more reliable benchmarking results.

1. Distribution O&M and Total A&G

Figure 9: Distribution O&M and Total A&G/Customer



[14] In performing this analysis, Concentric did not make any adjustment to, or otherwise allocate, A&G to the various utility functions, but rather used total A&G expense for benchmarking purposes. Allocation of A&G to the non-distribution functions, such as might be done under a fully allocated cost-of-service study, would reduce the total expense analyzed for those companies, including FEI, with transmission, storage, and other functions.

Figure 10: Distribution O&M and Total A&G/TJ

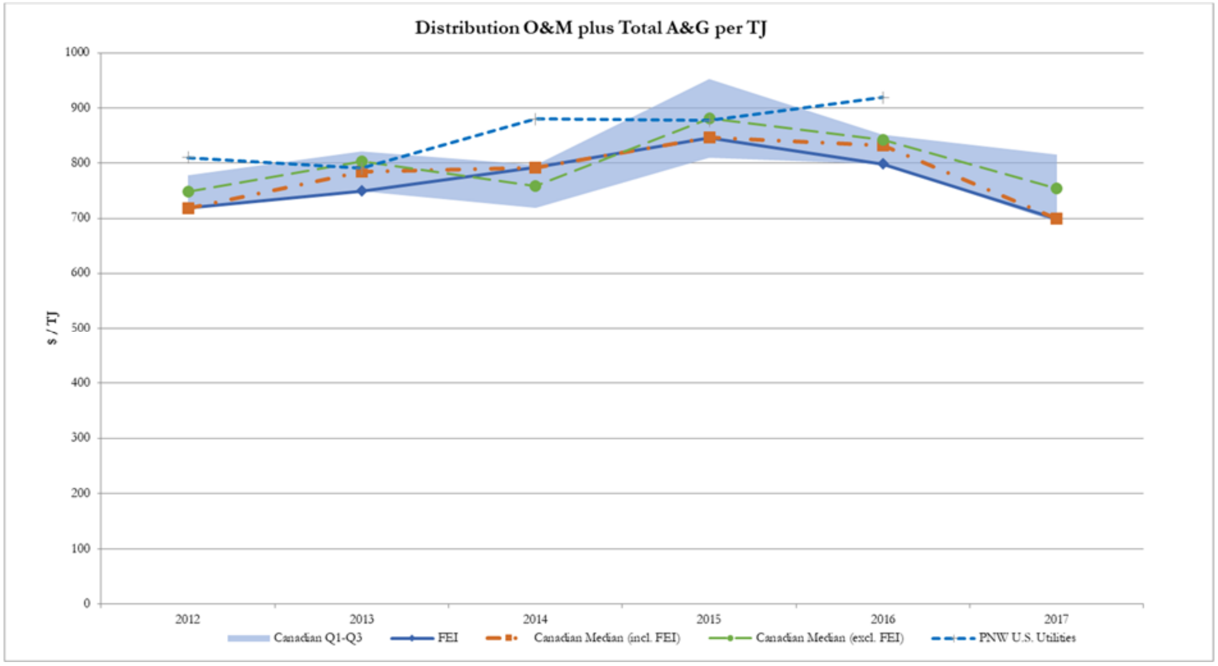


Figure 11: Distribution O&M and Total A&G /Employee

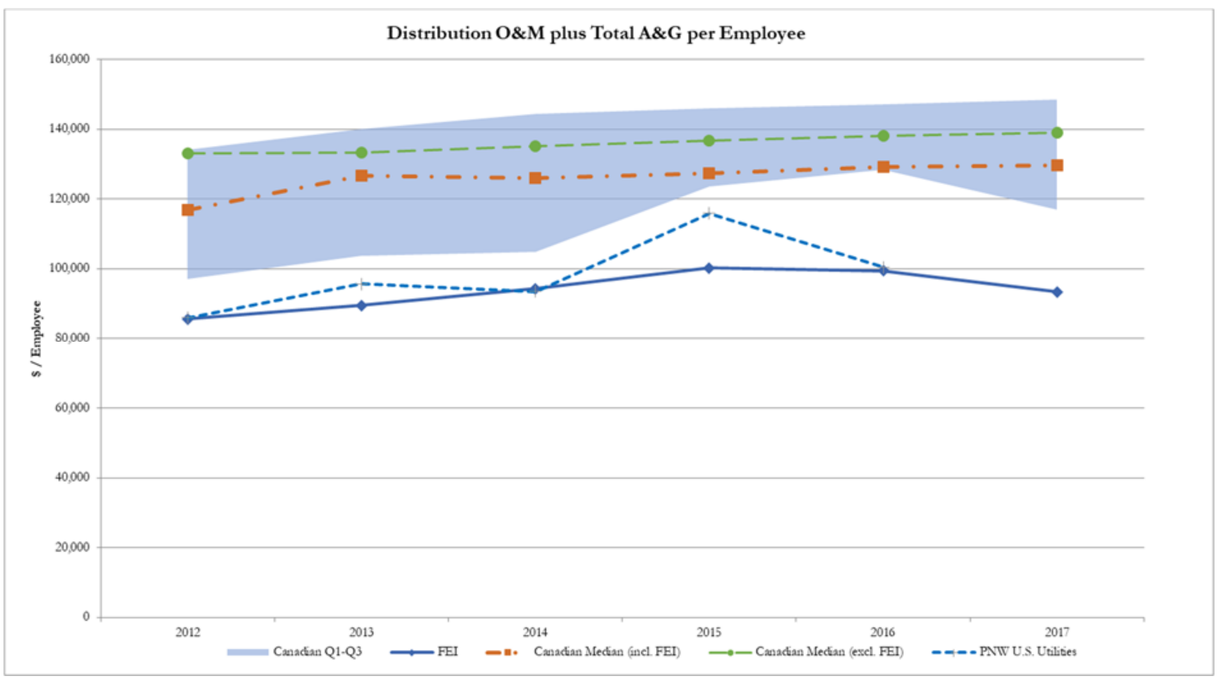
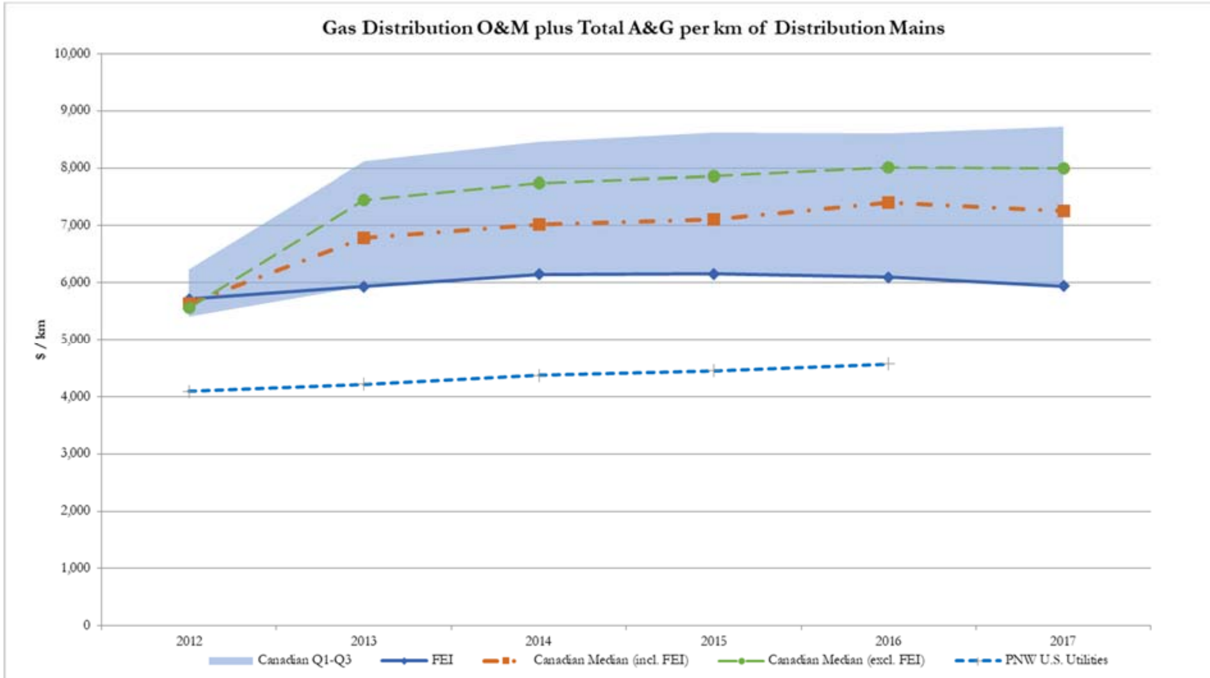


Figure 12: Distribution O&M and Total A&G/Kilometre of Distribution Mains



In terms of natural gas distribution O&M and total A&G per customer, FEI was near the Pacific Northwest U.S. company median and below the Canadian peer group median over the period of study, and its per customer costs increased modestly (nominal five-year CAGR of 0.16%) while the average costs for the peer groups increased more significantly (nominal CAGRs of 1.57%, 3.94% and 2.31% for the Canadian peer group median including FEI, the Canadian peer group median excluding FEI, and Pacific Northwest U.S. peer group, respectively).[15] For the companies in the Canadian peer group (including FEI), there is a distinct difference between companies with smaller customer bases versus those with larger customer bases, whereby smaller utilities, by customer count, tend to have greater distribution O&M and total A&G per customer, suggesting some economies of scale in distribution O&M and total A&G. While that phenomenon (*i.e.*, higher costs per unit for companies with less units, whether they be customers, volumes, or employees) is not unique to the per-customer metrics, in this case (as well as others, as described below), the peer group companies fell into more distinct dollar-per-customer groupings, which impacted not just the smallest and largest companies in the peer group, but also the companies that comprised the second and third quartile. That distinction is

15 Note that the CAGRs presented in the Study for the Pacific Northwest U.S. peer group are measured from 2012 to 2016 (*i.e.*, the last year of available data at the time of Concentric's analysis).

evidenced by the wider variance between the first and third quartile, which is shown by the shaded area in the figure.

On a distribution O&M and total A&G per TJ basis, FEI was at or below the Canadian peer group median (including FEI) over the study period, at or below the Canadian peer group median (excluding FEI) over the study period except for 2014, and below the Pacific Northwest U.S. peer group median. FEI's per unit costs have decreased over the period (nominal CAGR of (0.56)%). That is compared to nominal CAGRs of (0.56)%, 0.15% and 3.20% for the Canadian peer group median including FEI, the Canadian peer group median excluding FEI, and the Pacific Northwest U.S. peer group, respectively. For the years 2012 and 2017, FEI was the median utility, which resulted in the CAGR for FEI and the Canadian peer group (including FEI) being the same. In terms of distribution O&M and total A&G per employee, FEI was below the median over the period of study (except in 2014, when it was slightly above the Pacific Northwest U.S. median), with per employee costs growing more slowly than two out of the three peer groups medians shown in the figure (*i.e.*, nominal CAGR of 1.76% for FEI, compared to nominal CAGRs of 2.07%, 0.89%, and 3.95% for the Canadian peer group median including FEI, the Canadian peer group median excluding FEI, and the Pacific Northwest U.S. peer group, respectively). Finally, on a distribution O&M and total A&G per kilometre of distribution mains basis, FEI was below the Canadian peer group median for 2013 through 2017, and above the Pacific Northwest U.S. per group median over the period of the Study. FEI's per unit costs have increased only slightly over the study period (nominal CAGR of 0.77%), while the increase was more significant for the Canadian peer group including FEI, the Canadian peer group excluding FEI, and the Pacific Northwest U.S. peer group (nominal CAGRs of 5.19%, 7.52%, and 2.79%, respectively). The lower medians in 2012 for the Canadian peer groups are driven primarily by missing data for that year from a peer group company with relatively high costs per unit in other years.

2. <u>Net Plant</u>

Figure 13: Net Distribution Plant/Customer

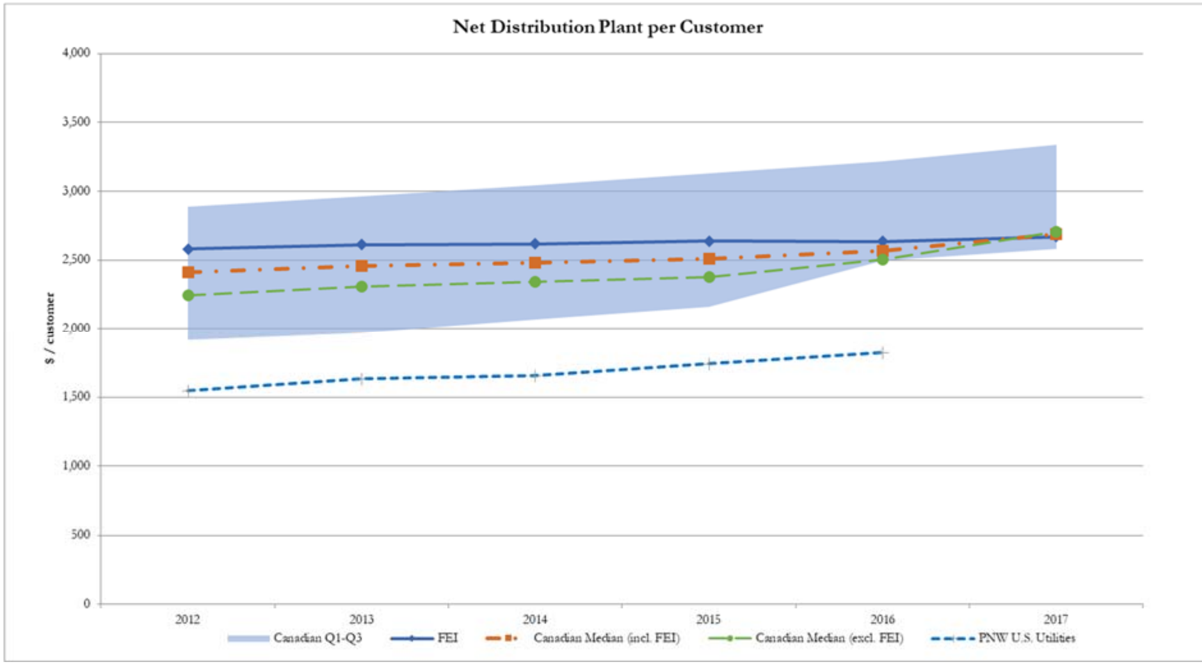


Figure 14: Net Distribution Plant/Employee

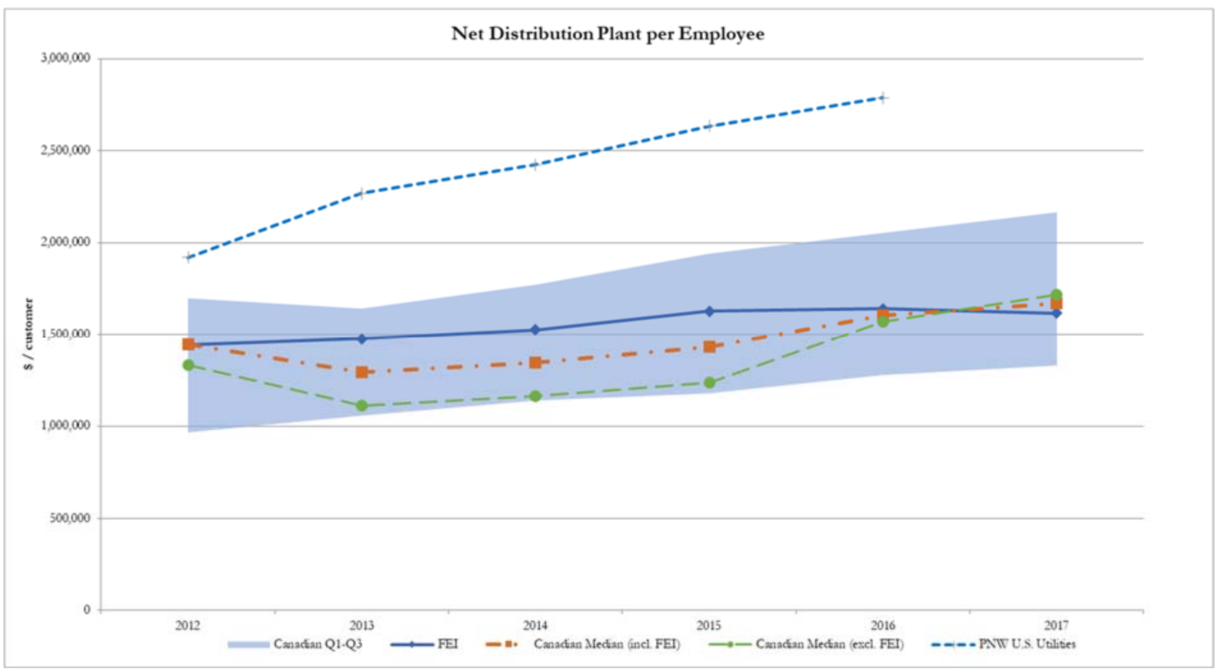
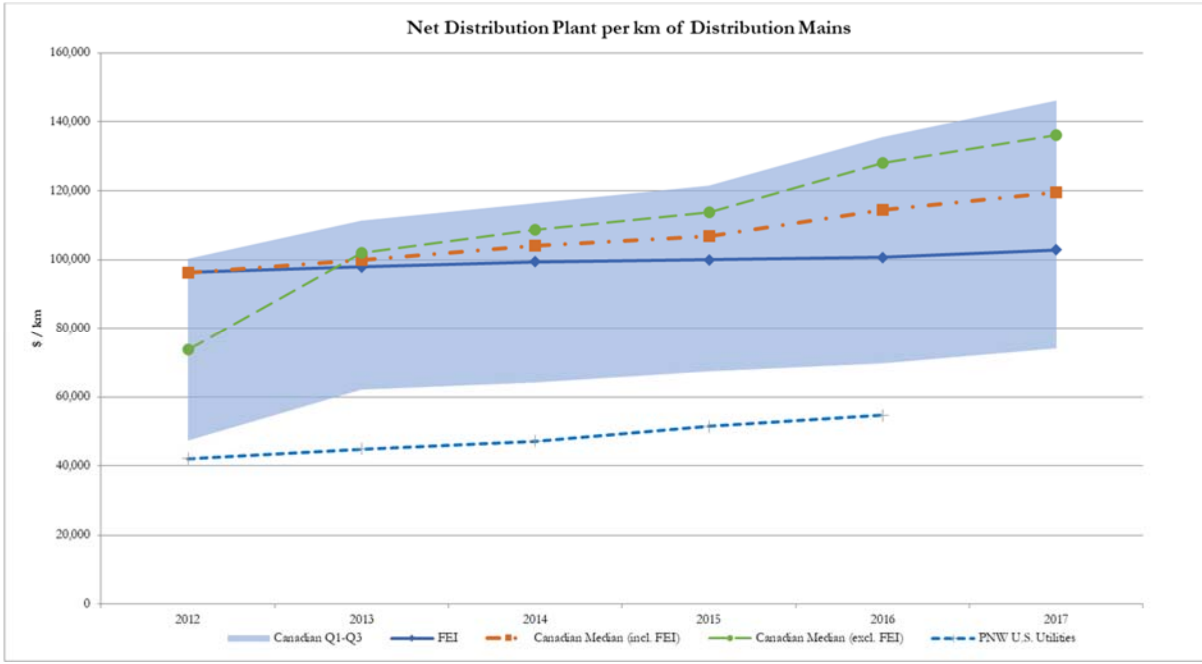


Figure 15: Net Distribution Plant/Kilometre of Distribution Mains



Compared to the Canadian utilities, FEI was above the median (both including and excluding FEI) on a net distribution plant per customer and net distribution plant per employee basis for the years 2012 through 2016, and approximately at the median in 2017. FEI's relatively flat level of net plant per customer over the course of the study period (*i.e.*, a nominal CAGR of 0.70%) eased this differential, whereas the Canadian peer group (both including and excluding FEI) experienced rising net plant per customer (*i.e.*, nominal CAGRs of 2.18% and 3.78%, respectively). The CAGR for the Canadian peer group is driven heavily by two of the peer group companies, which had growth in net plant that was significantly greater than the other companies in the peer group.

In comparison to the Pacific Northwest U.S. peer group, FEI is substantially above the group median on a net plant per customer basis. In fact, the Pacific Northwest U.S. peer group median is noticeably lower than the Canadian peer group medians and FEI in all years studied (*i.e.*, 2012 through 2016 for the Pacific Northwest U.S. companies). That result is driven by the net plant-per-customer of three of the utilities in the Pacific Northwest U.S. peer group, all of which had lower net plant-per-customer than each of the Canadian peer group companies in every year of the Study. In fact, one of those Pacific Northwest U.S. utilities (*i.e.*, Intermountain Gas) had net plant-per-customer that was approximately one-fifth the Canadian peer group median in each year of the Study. Like the Canadian peer group, the Pacific Northwest U.S. group also experienced an increase in net plant per customer over the study period (*i.e.*, a nominal CAGR of 4.19%). Lastly, while the Pacific Northwest U.S. utilities' median net plant per employee is noticeably above FEI and the Canadian peer group (in contrast to the Pacific Northwest U.S. utilities' net plant per customer, which was below FEI and the Canadian peer group), that result can be attributed to the fact that net plant per employee data was only available for two of the Pacific Northwest U.S. utilities, and both of those utilities were on the high end in terms of the range of net plant per customer. As such, the median net plant per employee of those two companies may not be representative of the median of the larger Pacific Northwest U.S. utilities group.

In terms of net distribution plant per kilometre of distribution mains, FEI was below the medians of both Canadian peer groups for the years 2013 through 2017. While net plant per kilometre of distribution mains increased steadily for the Canadian peer group including FEI and significantly for the Canadian peer group excluding FEI (nominal CAGRs of 4.40% and 13.04%, respectively), FEI's metric remained relatively flat (*i.e.*, a nominal CAGR of 1.31%). FEI was at the median of the Canadian peer group including FEI in 2012. As in the case of the O&M and total A&G per kilometre of distribution mains metric, the lower median in 2012 for the Canadian peer group excluding FEI is driven primarily by missing data from a peer group company with relatively high net plant per unit in other years. Similar to the net distribution plant per customer metric, both FEI and the Canadian peer group medians are substantially above the Pacific Northwest U.S. peer group median for the study period. Like the Canadian peer groups, the Pacific Northwest U.S. group also experienced an increase in net plant per kilometre of distribution mains over the study period (*i.e.*, a nominal CAGR of 6.73%).

3. A&G Expense

Figure 16: Total A&G/Customer

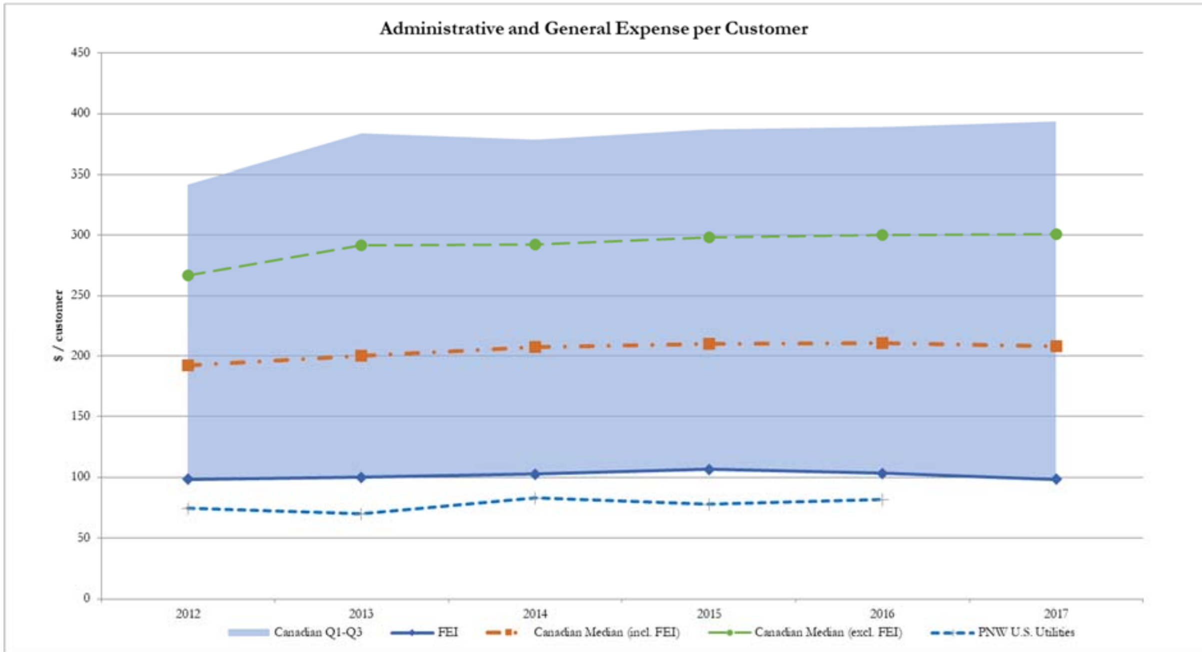


Figure 17: Total A&G/TJ

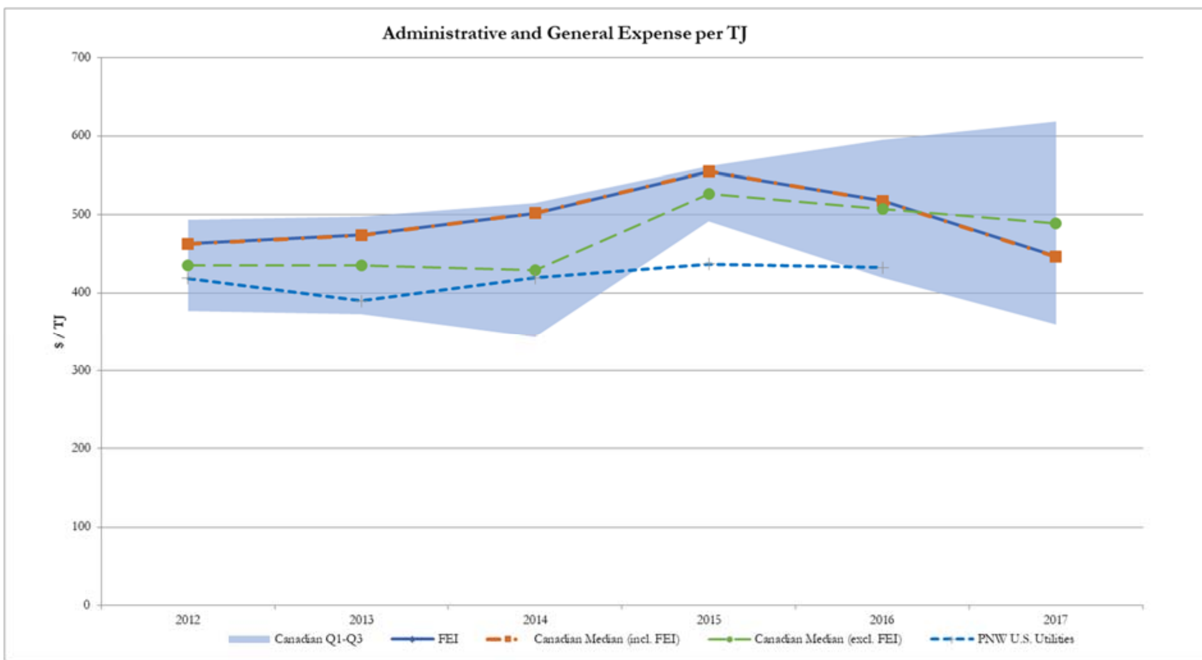


Figure 18: Gas Delivered per Employee

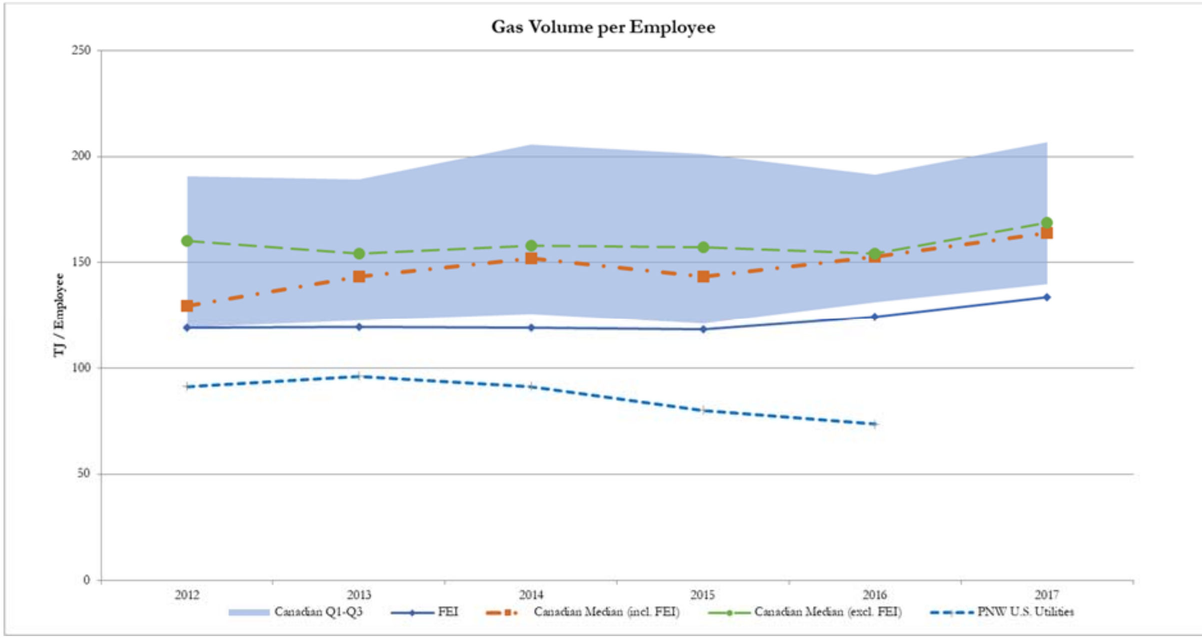
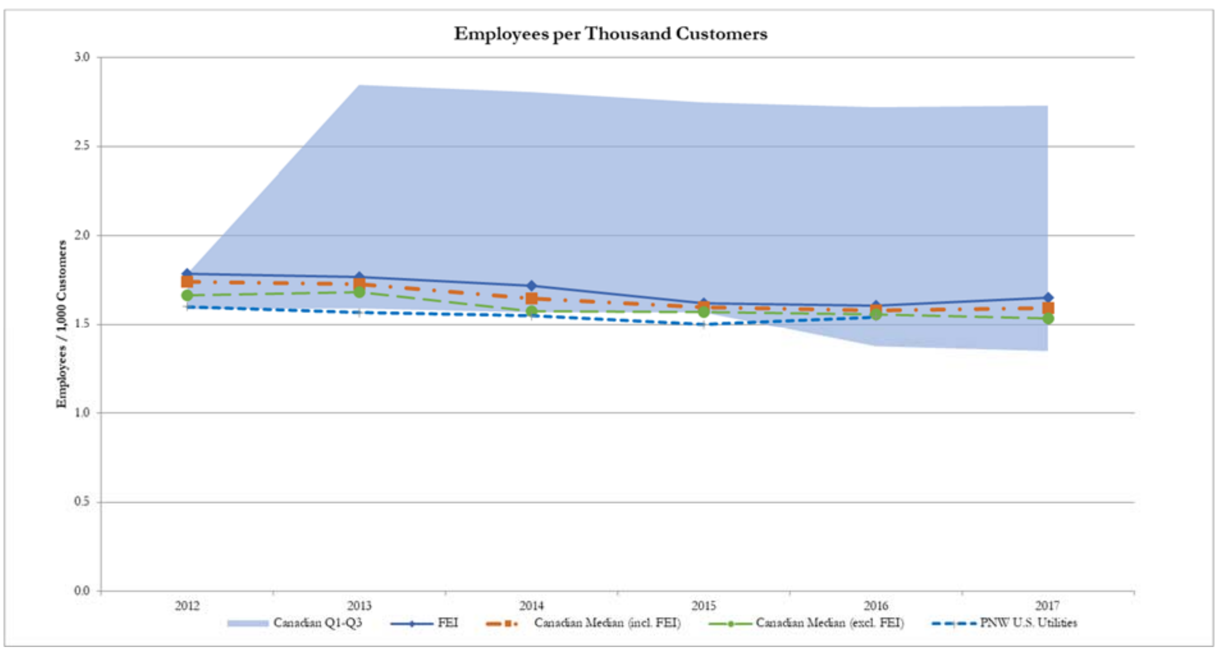


Figure 19: Employees per Thousand Customers



FEI had flat A&G expense per customer levels over the period studied (a nominal CAGR of 0.02%) and negative A&G expense per TJ growth (a nominal CAGR of (0.71)%). The Company was slightly above the Pacific Northwest U.S. peer group median but well below the Canadian peer group median (both including and excluding FEI) on a per-customer basis, and at the Canadian peer group median including FEI but above the Pacific Northwest U.S. peer group median and slightly above the Canadian median excluding FEI (with the exception of 2017, where FEI fell below the median) on a per-TJ basis.

Similar to the distribution O&M plus total A&G per customer metric, A&G expense per customer also exhibited a distinct difference between companies with smaller customer bases versus those with larger customer bases, as evidenced by the wider variance between the first and third quartiles, which is shown by the shaded area in the figure.

The figures above showing gas volume per employee and employees per thousand customers also provide information regarding the efficiency of the Company's workforce. The Company provided less volume per employee than the Canadian peer group median (both including and excluding FEI) over the period studied, but is only slightly above or at the Canadian peer group median (both including and excluding FEI) in terms of employees per thousand customers served. In addition, the lower volume per employee does not appear to have come at an overall higher cost, based on the OM&A results discussed above. Further, as discussed earlier in this report, volume-based metrics, such as volume per employee, can be driven by the customer mix of a utility (and the building stock, weather and customer usage characteristics), whereby companies with a higher percentage of commercial and industrial customers (and thus a lower percentage of residential customers) will have more volume delivered per employee, and visa-versa.

Both FEI and the Canadian peer group median (both including and excluding FEI) are well above the Pacific Northwest U.S. peer group median in terms of gas volume per employee, and moderately above the Pacific Northwest U.S. peer group median in terms of employees per thousand customers, in each year of the Study.

4. Customer Care Expense[16]

Figure 20: Customer Care Expense/Customer

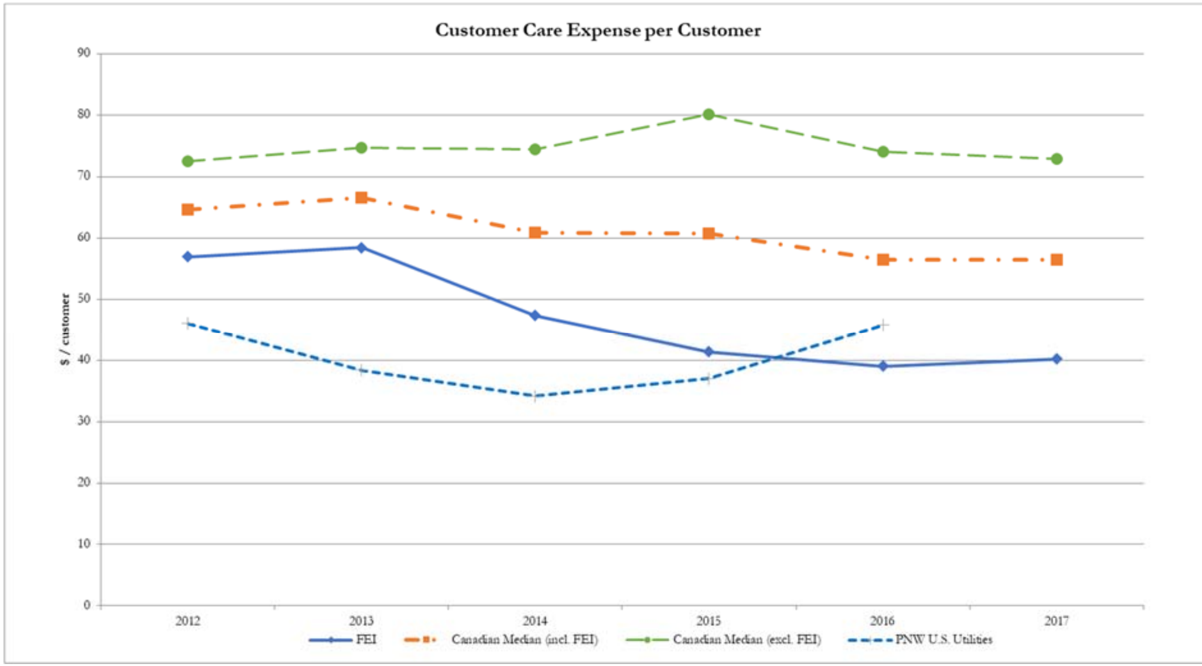
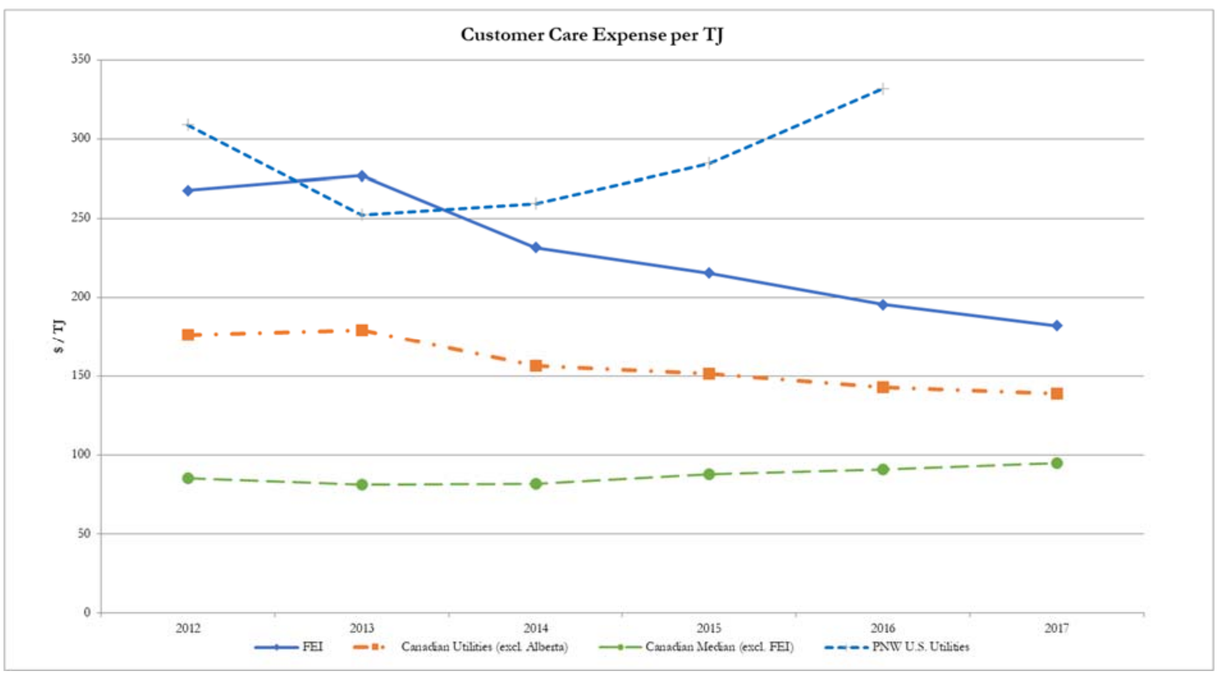


Figure 21: Customer Care Expense/TJ

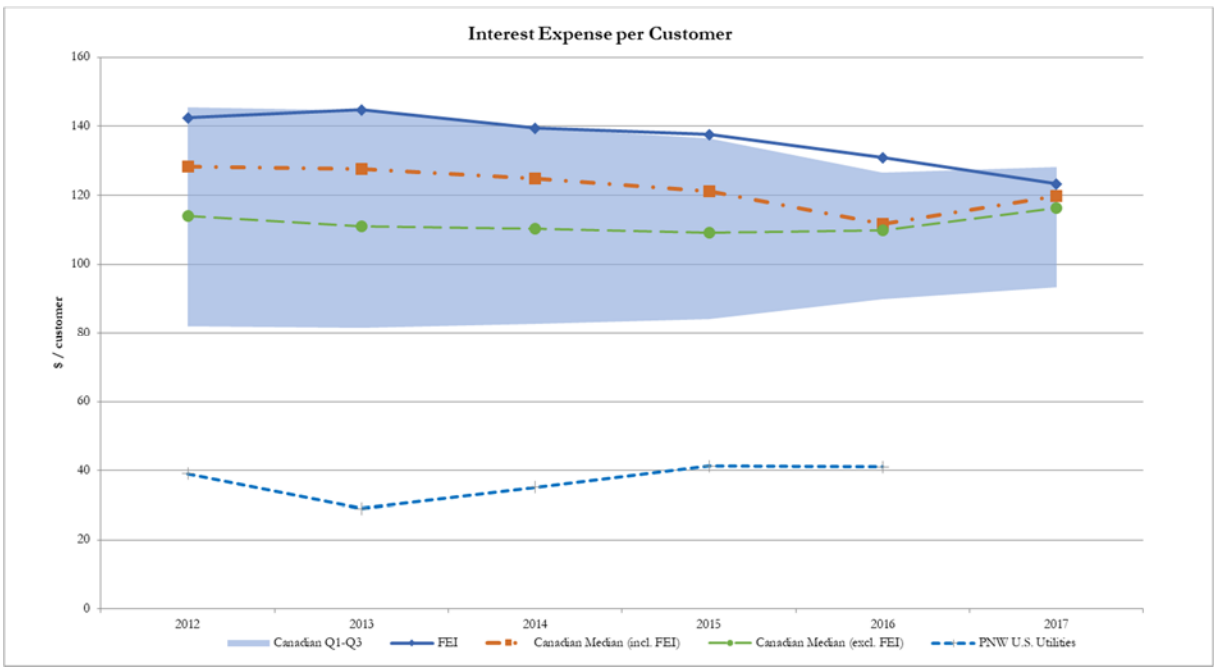


16 As mentioned earlier, since Alberta utilities do not provide certain customer care services (*e.g.*, billing, collections) to end-use customers, they are excluded from the customer care expense comparisons.

FEI's natural gas customer care expense decreased over the study period on both a per-customer and per-TJ basis (nominal CAGRs of (6.73)% and (7.40)%, respectively). On a per-customer basis, FEI was below the median (both including and excluding FEI) for the Canadian peer group for all years of the analysis. In comparison to the Pacific Northwest U.S. peer group, FEI began the study period above the peer group median but ended below the peer group median by 2016. On a per-TJ basis, FEI was above the Canadian peer group median (both including and excluding FEI) and below the Pacific Northwest U.S. peer group median in every year of the Study except 2013, decreasing the difference between the Canadian peer group median (both including and excluding FEI) over that time.

5. <u>Interest Expense</u>

Figure 22: Interest Expense/Customer



FEI's interest cost per customer has fallen over the period studied, but, consistent with its higher net plant-per-customer level, FEI's interest cost per customer exceeded both the Canadian and Pacific Northwest U.S. peer group medians. As with net plant-per-customer, the Pacific Northwest U.S. peer group median is noticeably lower than the Canadian peer group median (both including and excluding FEI) and FEI in all years studied (*i.e.*, 2012 through 2016 for the Pacific Northwest U.S. companies). Also, similar to the net plant-per-customer metric, that result is driven by the interest expense-per-customer of two of the utilities in the Pacific Northwest U.S. peer group, both of which had lower interest expense-per-customer than each of the Canadian peer group companies in every year of the Study. In fact, one of those Pacific Northwest U.S. utilities (*i.e.*, Intermountain Gas) had interest expense-per-customer that was approximately 10% of the Canadian peer group median in each year of the Study. It is important to note that while Concentric did not do a direct comparison of the capital structures at each peer group company, interest expense is driven not only by a utility's cost of debt, but also by the relative proportion of its rate base that is financed with debt (*i.e.*, its capital structure).

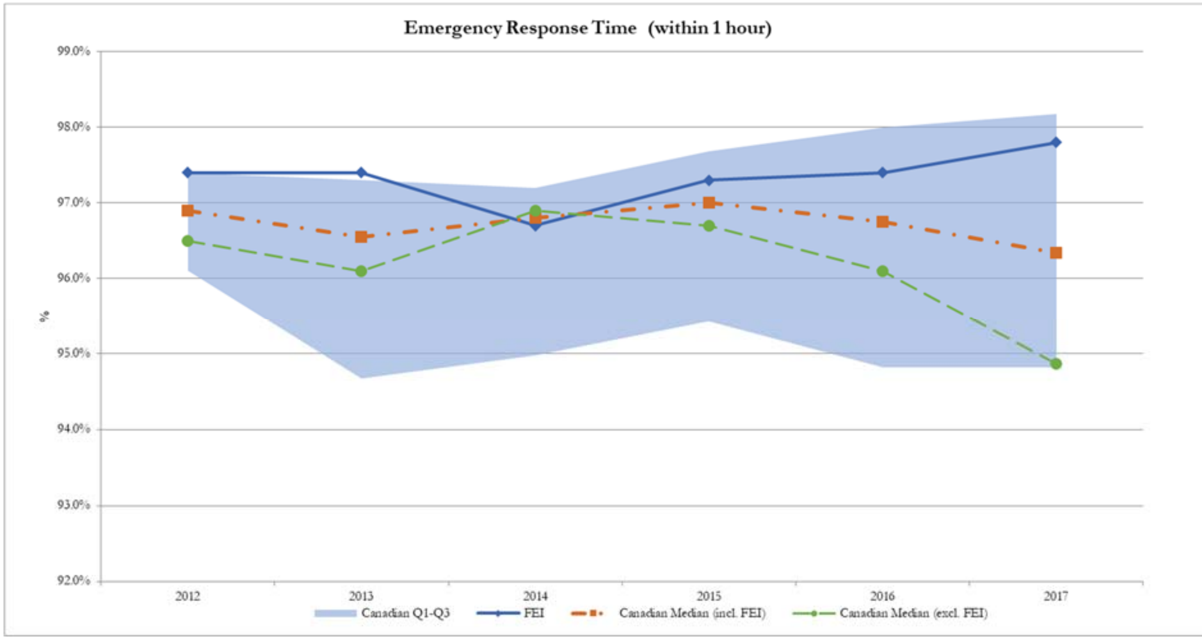
<u>Reliability and Customer Service Metrics</u>

The Study included a number of reliability and customer service metrics, including emergency response time, various call center related metrics, DSM expenditures, and GHG emissions. While those metrics do not provide direct information regarding financial efficiency, they can be viewed either in isolation or in conjunction with the financial metrics to provide information regarding the service level provided given the studied companies' cost levels. On these metrics, the top quartile is at the upper or lower end of the figure, depending on the metric.

Further, the RFP requested that metrics that can be used to evaluate utilities' capabilities to adapt to evolving industry dynamics and societal needs be considered. In Concentric's view, the metrics discussed in this section serve that purpose, as they not only measure reliability and customer service, which are of paramount importance to customers, but they also measure items related to changing industry dynamics, such as DSM programs and the desire to limit GHG emissions.

1. Emergency Response Time

Figure 23: Emergency Response Time



Emergency response time measures the percent of emergency calls responded to within one hour. FEI performed at or above the average Canadian peer group medians in each year of the study period except for 2014 and was consistently in the top half of companies. FEI's emergency response time was slightly below the benchmark established for performance-based ratemaking purposes of 97.7% for all years of the study, except for the most recent year (*i.e.*, 2017). Data was unavailable for the Pacific Northwest U.S. peer group.

While the figure appears to show a wide dispersion between the first and third quartile for this metric, all companies in the Canadian peer group were within 6% of each other over the course of the period studied, and the minimum for any company never fell below 92%.

2. Telephone Service Factor, First Contact Resolution and Abandonment Rates

Figure 24: Telephone Service Factor – Emergency

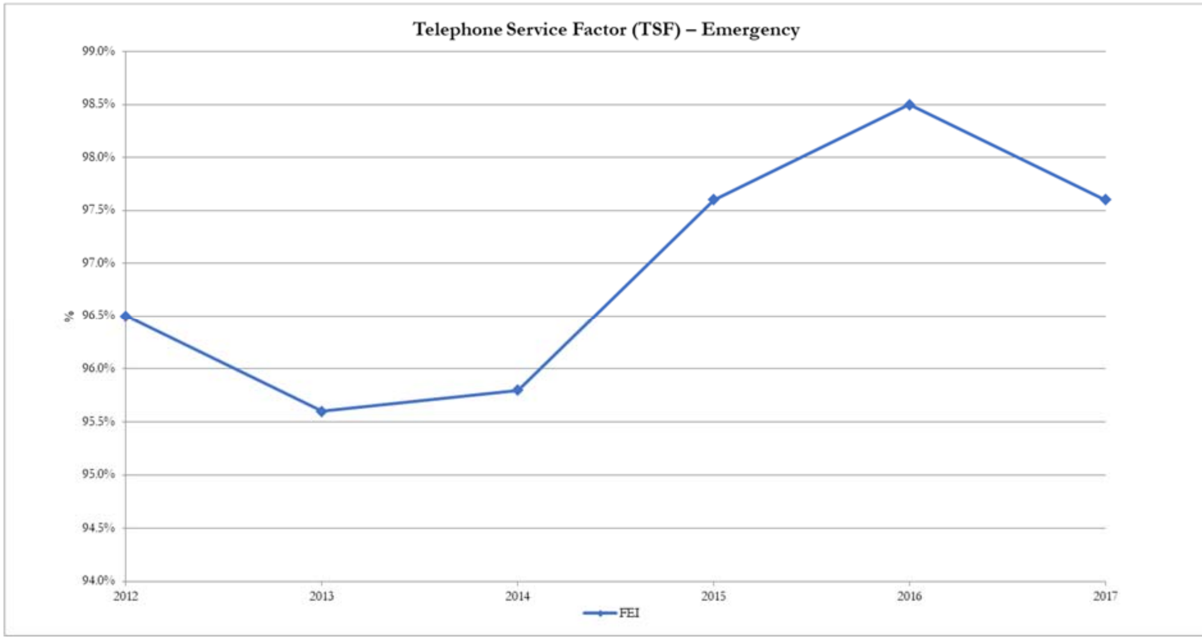
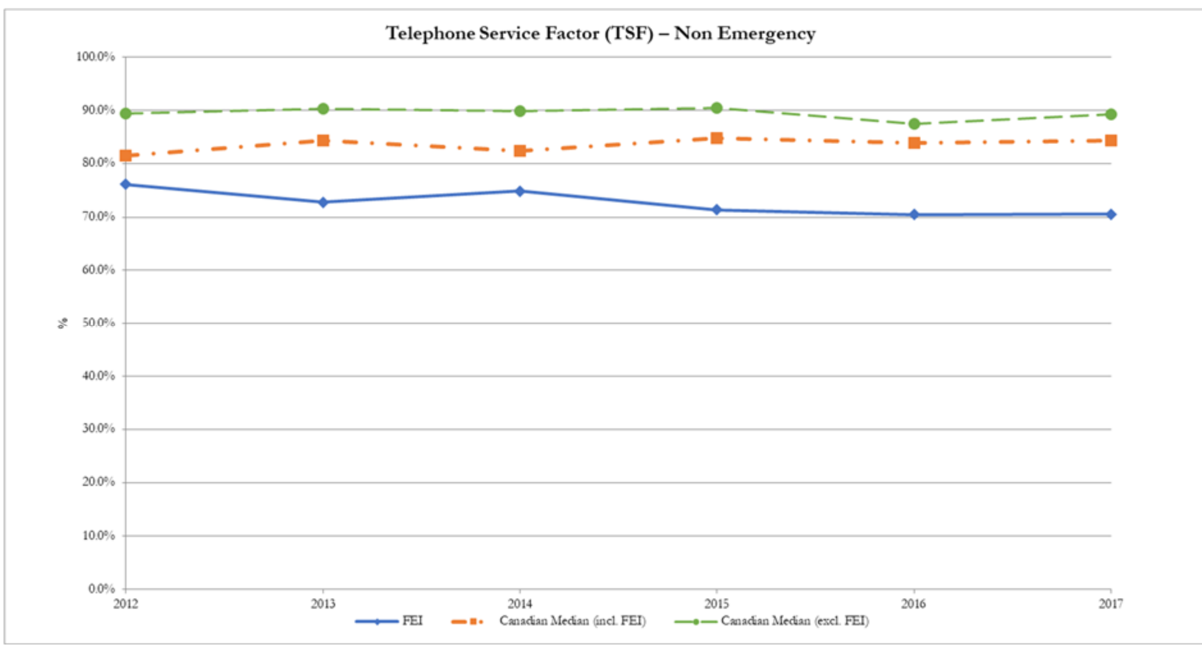


Figure 25: Telephone Service Factor – Non-Emergency

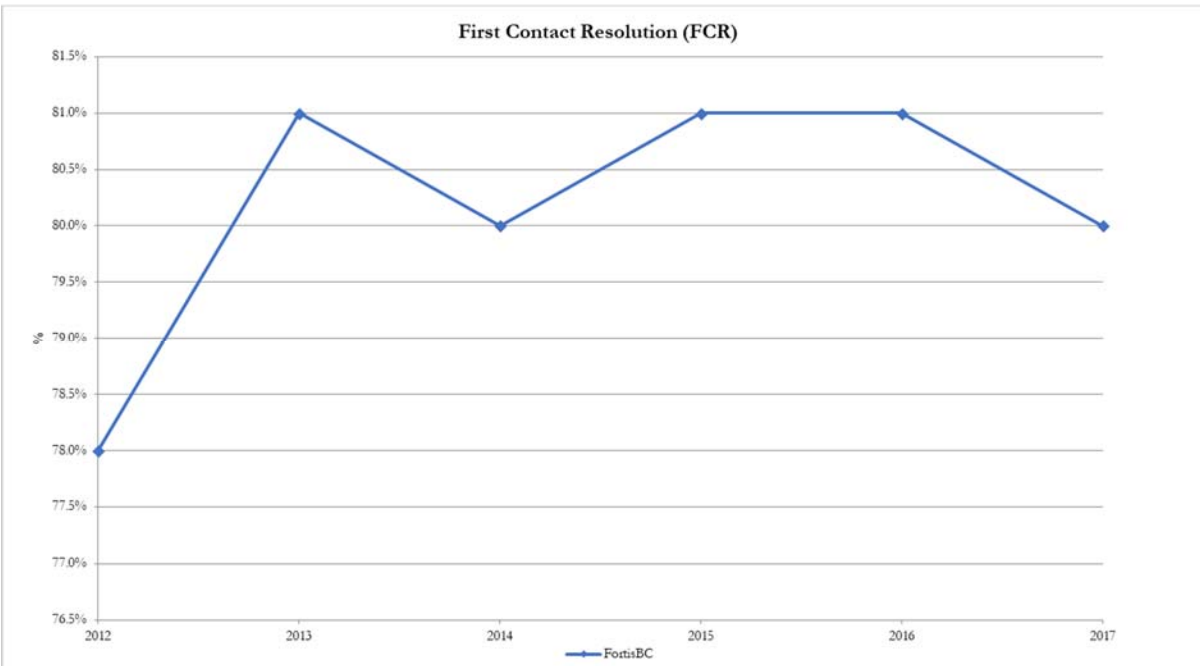


FEI consistently responded to over 95% of emergency calls within 30 seconds (TSF – emergency). There was an insufficient sample of peer group companies on which to compare FEI on the TSF – emergency metric. In terms of non-emergency calls (TSF – non-emergency), FEI answered between

70% and 80% of calls within 30 seconds over the period studied, placing it below the Canadian peer group medians (both including and excluding FEI), which ranged from 81% to 90%.

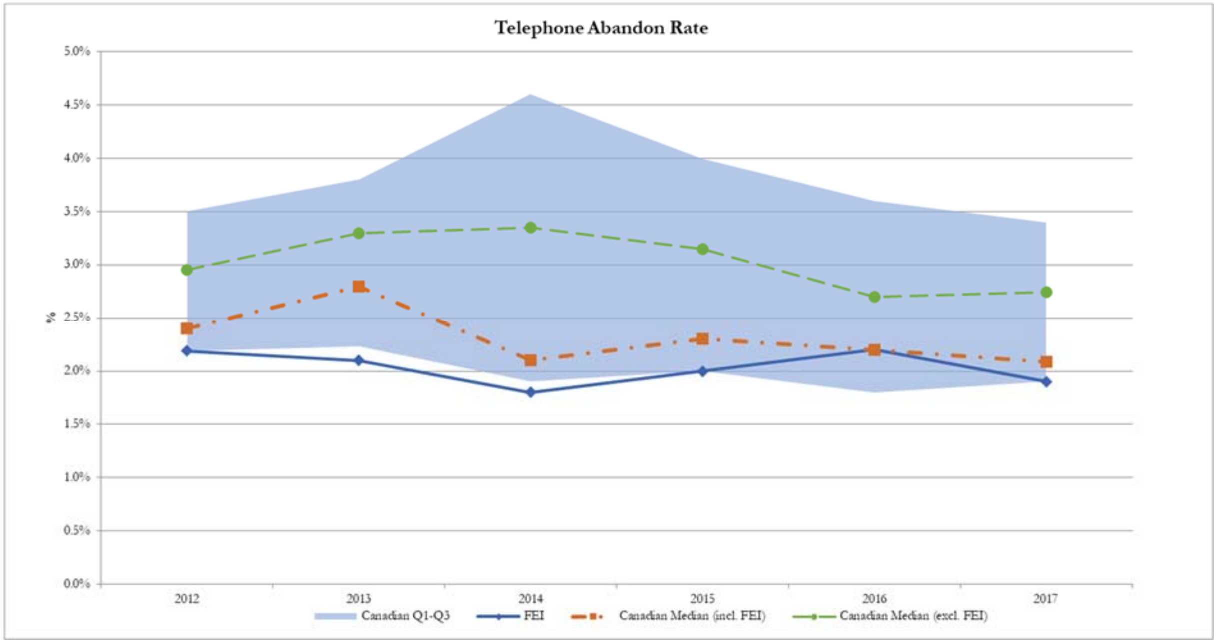
It is important, however, to also view TSF (and other service quality indicators) in the context of what the target TSF rate is for the utility. In this case, FEI's TSF target is 95% for emergency calls and 70% for non-emergency calls. FEI's TSF for both emergency and non-emergency calls was above that target for all years of the Study.

Figure 26: First Contact Resolution



FEI's FCR, which provides the percentage of customer calls FEI resolved with one call, was approximately 80% over the period studied. FEI's FCR was at or above its benchmark of 78% (established for performance-based ratemaking purposes) for all years of the Study. There was an insufficient sample of peer group companies on which to compare FEI on the FCR metric.

Figure 27: Telephone Abandonment Rates



In terms of the telephone abandonment rate, FEI performed better than the Canadian peer group median (both including and excluding FEI) over the period of study, with an abandonment rate of approximately only 2% of calls.

3. DSM Expenditures

Figure 28: DSM Expenditures (with incentives)/Customer

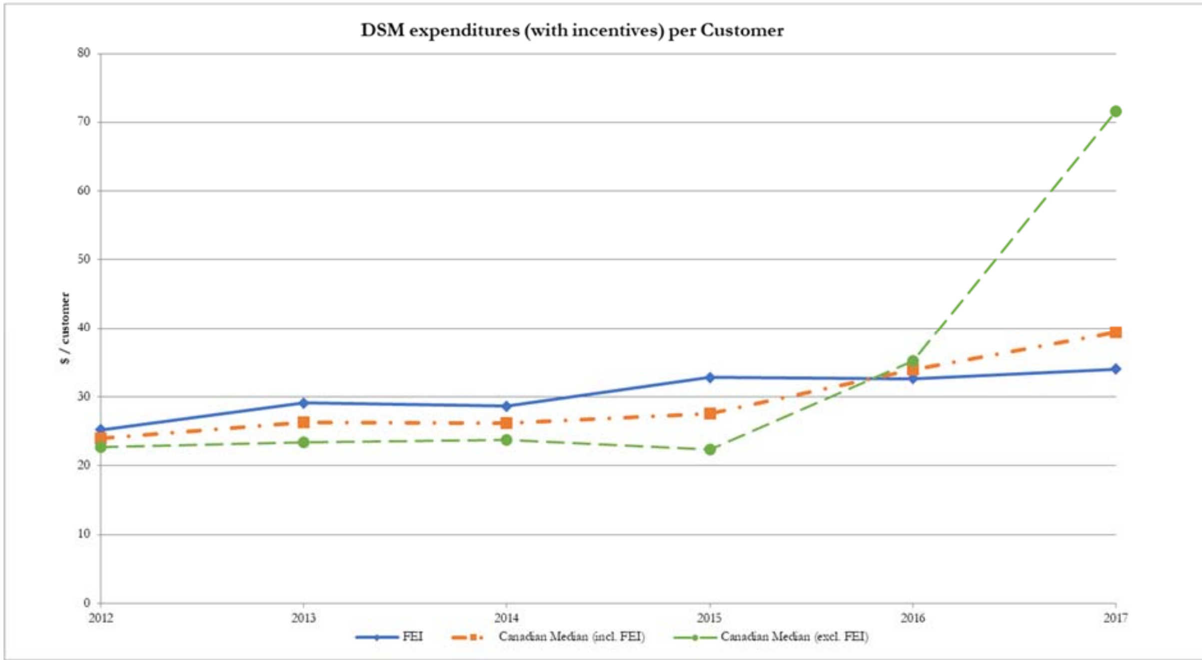


Figure 29: DSM Expenditures (without incentives)/Customer

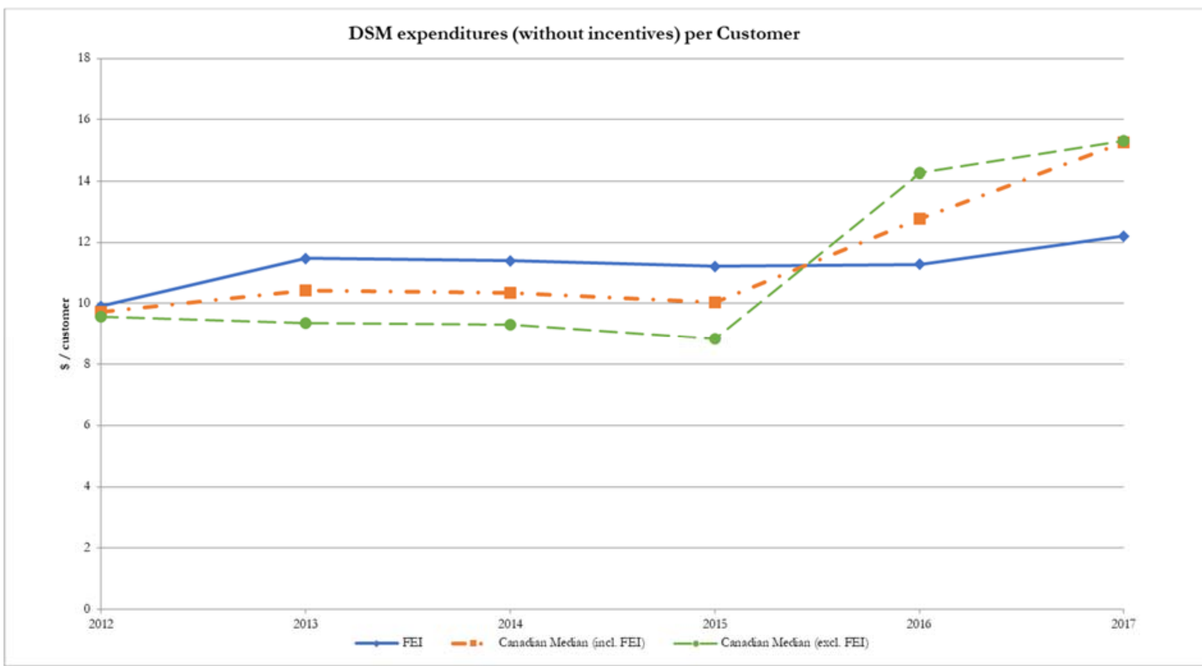
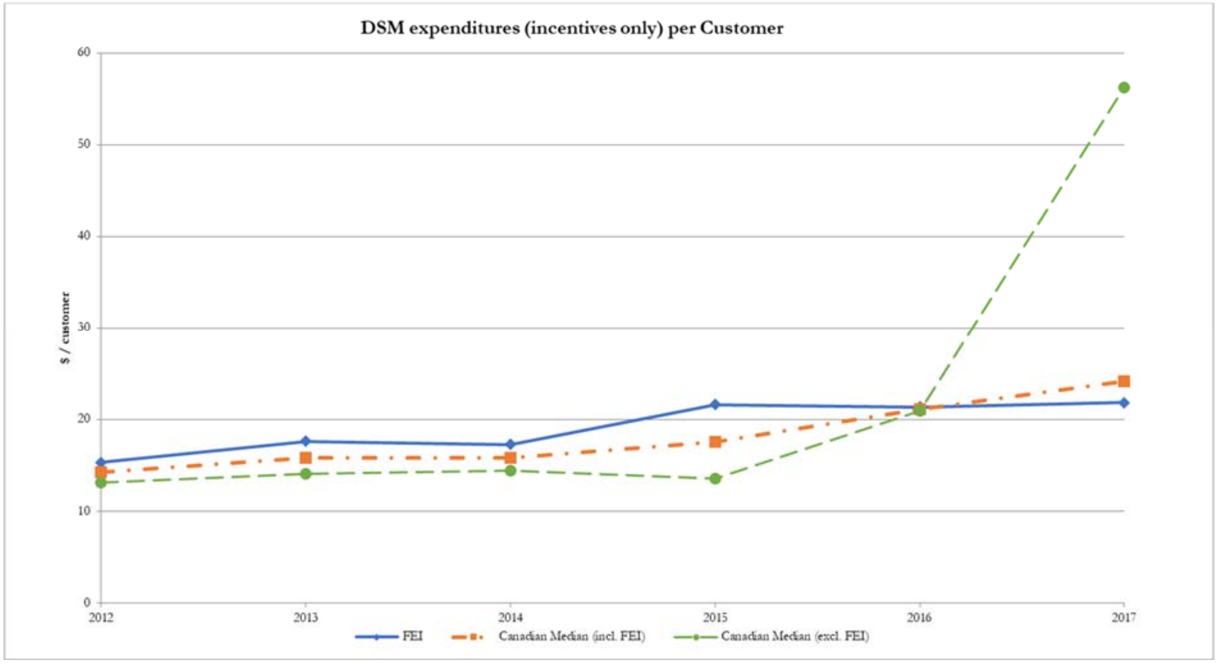


Figure 30: DSM Expenditures (incentives only)/Customer



FEI had higher total DSM spending (with incentives) per customer than the Canadian peer group medians (both including and excluding FEI) through 2015 but was lower for 2016 and 2017.[17] This information was not consistently reported by the Pacific Northwest U.S. peer group, and data was not available for more than four Canadian peer group companies, and thus the Pacific Northwest U.S. peer group and the shaded quartiles region are not presented in the figure. Similar to total DSM spending, FEI's DSM spending without incentives exceeded the Canadian peer group medians (both including and excluding FEI) through 2015, but fell below the industry medians in 2016 and 2017. FEI's DSM incentive only spending was higher than the Canadian peer group medians (both including and excluding FEI) from 2012 to 2015, at the median for 2016, and slightly below the median for 2017. The Canadian peer group median including FEI was driven up in 2015 and 2016 as two of the companies in the peer group approximately doubled their DSM spending over the period studied.

[17] Non-incentive expenditures include indirect costs associated with DSM programs (*e.g.*, program administration, communication and outreach, research and evaluation of the program, *etc.*).

4. <u>GHG Emissions</u>

Figure 31: GHG Emissions/Customer

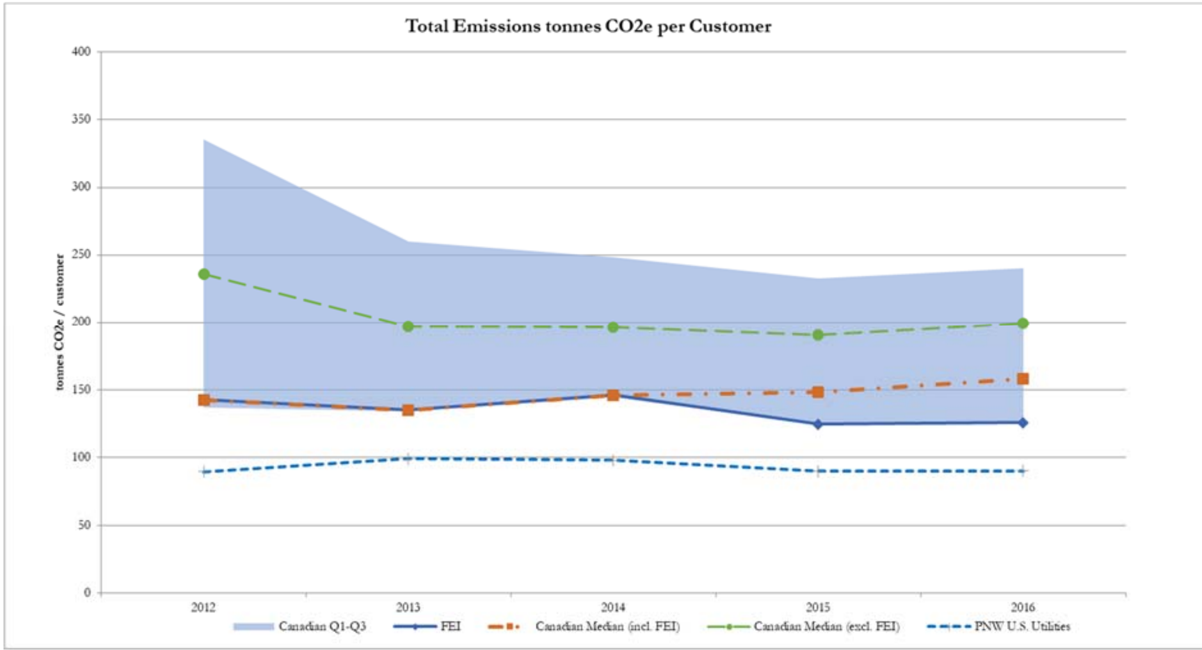
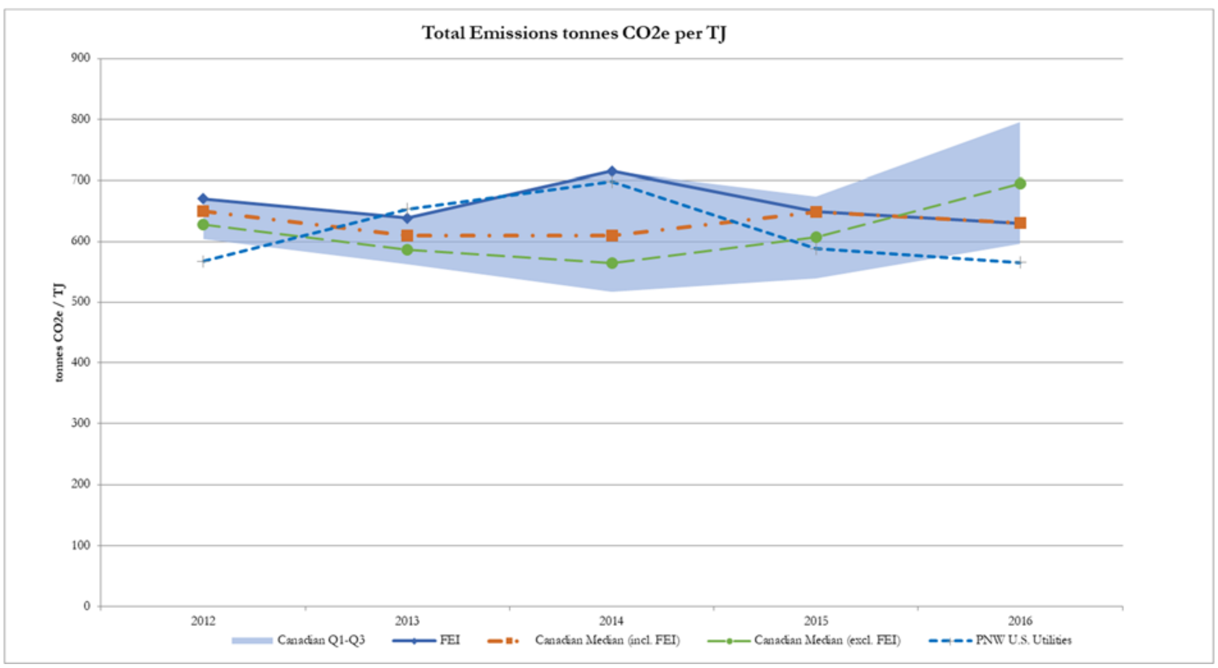


Figure 32: GHG Emissions/TJ



FEI had declining GHG emissions over the period studied on a per customer basis (CAGR of -(3.10) %), and had fewer emissions per customer than the Canadian peer group median (including FEI) for the years 2015 and 2016, but greater emissions per customer than the Pacific Northwest U.S. peer group.[18] FEI has had lower emissions per customer than the Canadian peer group median (excluding FEI) for all years of the Study. On a throughput basis, FEI has had decreasing emissions (CAGR of -(1.54)%) from 2012 to 2017. FEI's GHG emissions on a per TJ basis were above the Canadian peer group median (including FEI) for the years 2012 to 2014, but at the median for the most recent two years (*i.e.*, 2015 and 2016). FEI's GHG emissions on a per TJ basis were above the Canadian peer group median (excluding FEI) for all years except for 2016.

VI. SUMMARY AND CONCLUSIONS

The Study focused on a series of metrics designed to examine the relative efficiency of the Company in terms of its O&M expense profile, capital investment, reliability, customer service, and other factors. Benchmarking is a commonly employed analytical technique used across a wide variety of industries to compare a company's performance against an industry group, which serves as the benchmark. The benefits of benchmarking are its intuitive appeal and the ability to compare against companies chosen from within the same industry. Limitations of benchmarking include the fact that detailed data across companies beyond top line revenue and cost categories can be difficult to glean from public sources. Further, the benchmarking comparison is a relative one, and therefore does not offer insights into optimal performance in an absolute sense.

The industry peer groups used in the Study were selected according to criteria designed to produce peer groups with operating circumstances similar to FEI. Criteria used to select companies included their types of operations, their geographical location, and whether or not they were rate regulated. The peer group was also limited based on the companies for which data was publicly available and/or those companies that agreed to provide data in response to Concentric's survey. Concentric was able to develop Canadian and Pacific Northwest U.S. peer groups that were sufficiently large and that provided a reasonable basis on which to benchmark the Company's performance.

The Study focused on benchmarking metrics that measure financial efficiency, reliability, and customer service performance. These metrics were chosen in consultation between the Company and

18 As discussed earlier, Concentric relied on different sources for the Canadian (*i.e.*, Climate Change Canada's GHGRP) versus U.S. (*i.e.*, the U.S. Environment Protection Agency's Greenhouse GHGRP) data, which could contribute to some of the difference between the Canadian and Pacific Northwest U.S. peer group results.

stakeholders. In Concentric's opinion, the set of metrics used in the Study provides for a reasonably comprehensive overview of FEI's relative performance from both a financial and a non-financial basis.

Results Summary

The following figure summarizes the benchmarking analyses presented in the Study. Specifically, the figure presents the percentage difference between FEI's result and the Canadian peer group's median (including FEI) result, per metric, per year. For those metrics and years where FEI performed better than the median, the result is shaded green in the figure. Where FEI was at the median or there was an insufficient sample of peer group companies, no shading is used. For those metrics and years where FEI performed worse than the median, the result is shaded red in the figure.

Figure 33: Summary of Benchmarking Analyses

% Difference - FEI from Canadian Median	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	-27%	-28%	-28%	-29%	-30%	-32%
Distribution O&M + Total A&G per TJ	0%	-4%	0%	0%	-4%	0%
Distribution O&M + Total A&G per Employee	-27%	-29%	-25%	-21%	-23%	-28%
Distribution O&M + Total A&G per km of Mains	1%	-13%	-13%	-13%	-18%	-18%
Distribution Net Plant per Customer	7%	6%	6%	5%	3%	-1%
Distribution Net Plant per Employee	0%	14%	13%	14%	2%	-3%
Distribution Net Plant per km of Mains	0%	-2%	-4%	-6%	-12%	-14%
Administrative and General Expense per Customer	-49%	-50%	-50%	-49%	-51%	-53%
Administrative and General Expense per TJ	0%	0%	0%	0%	0%	0%
Customer Care Expense per Customer	-12%	-12%	-22%	-32%	-31%	-29%
Customer Care Expense per TJ	52%	55%	48%	42%	37%	31%
Interest Expense per Customer	11%	13%	12%	14%	17%	3%
Emergency Response Time (within 1 hr)	1%	1%	0%	0%	1%	2%
Telephone Service Factor - Emergency	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non-Emergency	-6%	-14%	-9%	-16%	-16%	-16%
First Contact Resolution	NA	NA	NA	NA	NA	NA
Telephone Abandon Rate	-9%	-25%	-14%	-13%	0%	-9%
DSM Expenditures (with incentives) per Customer	5%	11%	9%	19%	-4%	-14%
DSM Expenditures (without incentives) per Customer	2%	10%	10%	12%	-12%	-20%
DSM Expenditures (incentives only) per Customer	8%	11%	9%	23%	1%	-10%
Total Emissions tonnes CO2e per Customer	0%	0%	0%	-16%	-20%	NA
Total Emissions tonnes CO2e per TJ	3%	5%	17%	0%	0%	NA

In terms of the financial metrics, FEI outperformed or met the peer group median in seven out of the twelve metrics analyzed in all years studied. In general, FEI's performance was more favorable when expressed on a per-customer basis, and less favorable when expressed on a per-volume basis. As discussed herein, FEI has a high percentage of residential and commercial customers in its overall customer base, thus providing an explanatory factor in the difference between its results on the per-customer versus per-volume metrics. FEI's performance at or better than the peer group median includes FEI's performance at the broadest expense level analyzed (*i.e.*, distribution O&M plus total A&G) on a per customer, per volume, per employee, and per kilometre of distribution mains basis, as well as the Company's financial performance related to A&G expense on both a per-customer and per-volume basis. Based on Concentric's analysis of different categories of expenses, FEI performed less favorably, on a relative basis, in the customer care costs per unit of volume. That performance, however, is balanced by FEI's relatively favorable performance on a customer care costs per customer basis and may be more indicative of FEI's customer mix rather than its actual cost performance.

FEI performed less favorably than the peer group median on a net plant per customer and per employee basis until 2017, when it performed approximately at the peer group median. As discussed herein, that is indicative of FEI's relatively flat level of net plant over the course of the study period, whereas the Canadian peer group experienced rising net plant. FEI also had higher interest cost per customer than the Canadian peer groups, which is consistent with its higher level of net plant. Additionally, on a net plant per kilometre of distribution mains basis, FEI performed at the peer group median in 2012 and better than the peer group median in all subsequent years.

In terms of reliability, customer service, and other metrics, FEI performed at or better than the peer group median on two of the metrics in all years (CO_2 emissions per customer and telephone abandon rate); at or better than the median on four metrics for most years (emergency response time, and all three DSM-related metrics); and at or below the median in most or all of the years studied on two of the metrics (TSF-non-emergency and CO_2 emissions per volume). For two of the factors (*i.e.*, TSF – emergency and FCR), there was insufficient peer group benchmarking data with which to compare FEI. As discussed in the Study, it is important to also view service quality indicators in the context of what the target service quality indicator baseline is for the utility. In all years studied, FEI performed at or better than its established baseline for the TSF and FCR metrics.

In terms of DSM expenditures, FEI began the period studied with above peer group median spending but fell below the median by 2017. As discussed herein, however, the level of DSM expenditures is dependent on the availability of regulatory mechanisms for cost recovery and the utility's efficiency in deploying these programs.

In summary, Concentric examined FEI's performance on a stand-alone basis, and also analyzed FEI's performance relative to 13 utilities in Canada and the U.S. across six years and 22 metrics. In terms of analyzing FEI's performance on an isolated basis, the Company's OM&A and net plant have increased modestly over the period studied on a nominal basis (five-year CAGRs of 0.75% and 1.36%, respectively), and have decreased (in the case of OM&A) or remained flat (in the case of net plant) on a real basis (based on a five-year average annual increase in the Consumer Price Index of 1.39%). On a relative basis, the Company performed at or better than the peer group median in the majority of the financial metrics analyzed, with the exception of net plant per customer and per employee, interest expense per customer, and customer care expenses per TJ. In terms of service quality and reliability metrics, the results were more varied, but also require more context, whether it be understanding the target metrics to which the Company is performing (*e.g.*, for TSF and FCR), or the drivers behind the performance trends (*e.g.*, for DSM spending). Where possible in the Study, Concentric captured that context in order to provide perspective regarding the Company's benchmarked results.

Appendix A: Data Survey Template – Natural Gas Companies

	Metric	Description of Metric	2012	2013	2014	2015	2016	2017	Comment
	Determinants								
1	# of Customers	# of Total Customers Served							
2	# of FTE Employee	# of FTE Employees (serving Gas Operations only for companies with both Electric and Gas Operations)							
3	Volume Sold	Total Energy Delivered (Please specify Unit in the "Comments" column)							
	Reasonableness of Proposed Investments and Capital Expenditures								
	Net Plant								
4	Intangible Plant								
5	Production Plant								
6	Storage Plant (Underground, LNG, and / or Other)	This includes underground storage; LNG storage; and all other types of storage							
7	Transmission Plant								
8	Distribution Plant								
9	General Plant								
10	Other Plant	Please specify what is included in the "Other" category in the "Comment" Column.							
11	Total Net Plant								
12	Rate Base	Total Rate Base							
	Prudency of Costs in Rates								
	Operating, Maintenance and Administration (OM&A)	This includes all O&M costs net of capitalized overheads							
13	Production Expense (excluding gas commodity costs)								
14	Storage Expense (Underground, LNG, and / or Other)	This includes expenses associated with underground storage; LNG storage; and all other types of storage							
15	Transmission Expense								
16	Distribution Expense								
17	Administrative and General Expense								
18	Customer Care Expense	This includes Customer Accounts and Customer Service & Information Expenses							
19	Other O&M Expense	Please specify what is included in the "Other" category in the "Comment" Column							
20	Total O&M Expense (excluding gas commodity costs)								
21	Total Interest Expense	This measures the total Interest Expense							
	Safety, Reliability of the system and Quality of the service								
22	Emergency Response Time	Percent of calls responded to within one hour							
	Customer Care Service Levels								
23	Telephone Service Factor (TSF) – Emergency	Number of emergency calls answered within 30 seconds divided by number of emergency calls received							
24	Telephone Service Factor (TSF) – Non Emergency	Number of non-emergency calls answered within 30 seconds divided by number of emergency calls received							
25	First Contact Resolution (FCR)	% of customers who achieved call resolution in 1 call							
26	Telephone Abandon Rate	Total # of Abandoned Calls divided by total number of answered calls plus abandon calls							
	Other								
27	Demand Side Management (DSM) expenditures with incentives	This includes DSM expenditures with incentives							
28	Demand Side Management (DSM) expenditures without incentives	This includes DSM expenditures without incentives							
29	GHG Emissions	Please include Direct Emissions							

Appendix B – Canadian Utility Data Gathering Process

Data Gathering

Concentric began the data gathering process by reviewing public sources to assess the availability of data for the potential proxy companies. Concentric's research indicated that, for Canadian utilities, publicly-available data would be insufficient for the Study. That conclusion was based on the following factors:

- Data was not widely enough reported and available to calculate and analyze the specific benchmarking metrics chosen for the Study. For example, Canadian utilities do not universally and consistently report/present their financial data by functional category (*i.e.*, production, transmission, distribution, *etc.*). Similarly, OM&A expenses tend to be reported at one aggregated level and in some instances include the cost of natural gas (for gas companies).
- The data was not consistently available for all years. For example, for certain companies, Concentric found some relevant data for certain years through rate case documents. However, since rate cases are not consistently filed on an annual basis, data obtained from rate case documents was insufficient for purposes of benchmarking.
- For certain companies, the reporting format for the data that was publicly available was not reported consistently from year to year. For example, certain reported categories would change from one year to the other. Additionally, some companies changed their reporting period from calendar year to fiscal year during the period of the study.

Based on Concentric's finding that publicly-available data would be insufficient for the purposes of benchmarking FEI against other Canadian utilities, Concentric developed a data survey for use in the direct request of data from Canadian utilities. Specifically, Concentric initiated a formal outreach process requesting the specific data elements provided in Appendix A to the Study. Concentric requested that participants provide their data via a Microsoft Excel template that Concentric created. The goal of the template was to ensure that the data provided would be in a consistent format. In addition, the use of such a template reduces errors and limits the need to go back to the survey respondents to ensure that data is being provided on a comparable basis.

Of the companies contacted, Concentric received data from 63% of gas utilities surveyed. Some survey respondents requested that their data be maintained on a confidential basis in return for providing the data for Concentric's analysis. Concentric agreed to that condition in consultation with

FEI, as confidential treatment of the data was critical to Concentric receiving such a high participation rate from the surveyed companies. Concentric offered to take the following specific steps to preserve the confidentiality of the data provided:

- Mask the name of the companies while presenting the results.
- Disclose the name of the companies that are part of our analysis in one list within the report.
- Present only normalized data (*e.g.*, $/customer or $/volume).
- The raw data provided by each company to Concentric would not be shared with anyone, including FEI personnel, other than Concentric personnel working on the Study.

Data Retrieval and Validation

Concentric took steps to ensure that the data provided by the companies was accurate and was reported in the format requested. Even with the use of a standard template, Concentric still performed several iterations of data review with the survey participants to understand, validate and normalize the data.

After receiving the data, Concentric critically reviewed the data to identify potential discrepancies and anomalies. When Concentric identified potential discrepancies or anomalies, Concentric followed-up with the relevant companies to understand the data and/or obtain supplemental information. On a test basis, Concentric also independently checked survey data against the limited publicly-available data that Concentric had collected to verify the survey data's correctness.

Other instances that required follow-up with the survey respondents included:

(1) Some companies did not initially categorize expenses by the functional categories requested, so Concentric worked with these companies to provide the data in the format requested. Concentric provided the detailed descriptions of what type of items belong in each category to help categorize the data correctly. Concentric relied on the U.S. Federal Energy Regulatory Commission's Uniform System of Accounts extensively for this purpose.

(2) Concentric also ensured that the financial data provided matched the volume and customer data provided in terms of ensuring that the data provided covered the same services and customer types. Specifically, Concentric verified with the companies that the number of

customers and volumes reported matched the financial data associated with serving those customers and volumes.

(3) In one instance, a respondent reported weather normalized volumes and Concentric requested actual volume to ensure that data was being compared on a consistent basis across companies.

Based on that process, Concentric was able to include a significantly greater number of Canadian utilities in the Study while ensuring that the data was incorporated in the analyses on a consistent basis.

Benchmarking Study

Prepared for:

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February 11, 2019

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TABLE OF CONTENTS

I. INTRODUCTION

FortisBC Inc. ("FBC" or the "Company"), retained Concentric Advisors, ULC ("Concentric") in February 2018 to conduct a benchmarking study on utility efficiency (the "Study"). The Study encompassed a review of the Company on a stand-alone basis and a comparison of the Company to Canadian and U.S. electric utilities.[1] For the comparative analysis, the Study focused on a series of metrics designed to examine the relative efficiency of the Company in terms of its operations and maintenance ("O&M") expense profile, capital investment, reliability, customer service, and other factors.

II. LIMITATIONS AND CAVEATS

The following are the limitations and caveats associated with the Study:

- Concentric did not audit or otherwise independently validate the data provided by FBC or other Canadian utilities. While our analysis included a careful review of the data to identify inconsistencies, as well as multiple rounds of communications with the Company and its peers through which Concentric was able to resolve data issues and place the companies on a comparable basis, we relied on FBC and the companies in our survey to provide complete and accurate data that was consistent with the benchmarking categories.
- Because the majority of the data provided by the Canadian peer companies was not otherwise publicly available, the Canadian utilities provided their information on a confidential basis. Concentric listed the companies in Figure 1, below, but otherwise masked the names of the utilities in our analyses and figures to preserve that confidentiality. Further, we did not share peer group-specific details or data (other than those disclosed in this report) with FBC.
- Accounting policies and procedures can impact utility companies' reported financial results, particularly when those results are used for comparative purposes. For instance, factors that can impact relative expense levels include the capitalization policies, capitalization rates, and cost allocation practices that a utility uses.[2] The actual amount of dollars that are split between expense and capital projects will also depend on the overall level of capital expenditures incurred in a given year. In other words, the relative level of each company's operations,

1 Concentric also conducted a gas utility study documented in a separate report.

2 FBC, for instance, reduced its capitalization rate starting in 2014, going from 20% to 15%. All else being equal, that would result in greater amounts of administrative and general ("A&G") expenses resulting from the reduced capitalization rate, with lower amounts of capital expenditures.

maintenance, and administrative ("OM&A") expenses and capital expenditures depends on: (a) the level of capital expenditures it incurs; and (b) the rate at which it allocates labour and overhead costs to capital projects. As such, normalizing for those differences between companies would be extremely difficult, particularly when assessing relative expense levels over time.[3] The use of peer groups is designed to mitigate those risks in two ways. First, use of companies in the same industry (*i.e.*, regulated utilities) is intended to capture, at a high level, companies with similar capital expenditure needs and capitalization procedures. Second, while each company may apply different capitalization ratios and have differing levels of capital expenditures within the bounds of industry norms, the use of multiple companies in the peer group is intended to mute the impact that any one company's policies and procedures can have on the overall results. It is important to recognize, however, that such differences may exist, and could impact the financial results of any one company when viewed in isolation. Further to this point, Concentric analyzed both expense and net plant figures to provide a more complete review of FBC's financial position and cost structure relative to the peer group companies.

- Financial data are expressed in own-country terms, without adjustment to account for fluctuating exchange rate differentials. For that reason, the U.S. data are presented separately from the Canadian data in each figure in the Study and are excluded from the Canadian peer group median and quartile calculations. That ensures that differently-denominated financial results are not factored together in the benchmarking results. Over time, sustained exchange rate differentials between Canada and the U.S. can contribute to differences between the Canadian companies (including FBC) and the U.S. companies, particularly in more recent years, as the exchange rate difference was more pronounced.[4] Concentric did not attempt to adjust for exchange rate differences, as it would require the introduction of a cross-border

[3] Concentric also inquired of the Canadian peer group companies: (a) how their overhead capitalization rates changed over the period studied; and (b) whether they had any significant changes in accounting policies over the period studied. Unsurprisingly, for those companies that responded, there was a diversity of practice in terms of the method of allocating A&G expenses to capital projects, as well as the rates at which such allocations are done. In addition, of those companies that responded, only one reported a change in accounting policies over the period studied that impacted their reported O&M costs.

[4] Specifically, the U.S. dollar to Canadian dollar exchange rate was close to parity in the 2012 to 2013 timeframe, but the U.S. dollar began to strengthen in 2014. For 2015 through 2017, the exchange rate was consistently at or above 1.00 U.S. dollars to 1.20 Canadian dollars (*see*, *e.g.*, https://www.bloomberg.com/quote/USDCAD:CUR, accessed July 18, 2018).

index (such as the World Bank's purchase power parity index), and such an index would have to consider capital investments made over many years and is beyond the scope of this study.

III. DESCRIPTION OF FBC

FBC operates an integrated regulated electric utility that owns hydroelectric generating plants, high voltage transmission lines, and a large network of distribution assets in the southern interior of British Columbia ("BC"). FBC serves approximately 172,300 direct and indirect customers throughout south central BC, including Kelowna, Oliver, Osoyoos, Princeton, Trail, Rossland, Castlegar, and Creston, and indirectly serves 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.

FBC is an indirect wholly-owned subsidiary of Fortis Inc.

IV. INDUSTRY BENCHMARKING METHODOLOGY

A. Overview

Benchmarking is a commonly employed analytical technique used across a wide variety of industries to compare a company's performance against an industry group, which serves as the benchmark. Comparator companies are typically chosen from within the same industry, and screens are typically applied to narrow the field to companies with reasonably comparable operations. Company service offerings, size, geography, age of assets, *etc.*, may be used as screens, or as variables used to explain performance differences. On a given performance attribute (*e.g.*, O&M expenditures per unit of output), certain explanatory measures (*e.g.*, average, median, quartile, *etc.*) determine average and best of class performance, and help to identify performance gaps against those standards. Benchmarking is often conducted for a limited number of time periods, or even a single year.

The benefits of benchmarking are its intuitive appeal and the ability to compare against companies chosen from within the same industry. Even though no two companies face identical operating circumstances, benchmarking provides a view into industry performance and provides perspective for regulators and stakeholders. Limitations of benchmarking include its inability to quantify causal relationships between operating circumstances and costs, and between inputs and outputs.[5] Detailed data across companies beyond top line revenue and cost categories can also be difficult to glean from public sources. Further, the standard benchmarking comparison is a relative one, and therefore does not offer insights into optimal performance (sometimes referred to as the "efficient frontier") in an absolute sense.[6]

B. Determination of Industry Peer Groups

The industry peer groups used in the Study were selected according to criteria designed to produce peer groups with operating circumstances similar to FBC. The criteria, which are listed below, were also determined to allow for a peer group size that would provide a sufficiently broad perspective for industry comparisons.

- Operations: The companies in the FBC peer group are a mix of vertically-integrated (*i.e.*, generation, transmission and distribution), transmission and distribution, and distribution-only electric utilities. Because the peer group companies provide similar services, it is reasonable to assume that they will broadly have similar business functions within their companies in order to provide those services, thus providing a basis upon which to compare the financial and non-financial metrics of FBC.
- Geography: The Study includes Canadian electric utilities and utilities in the Pacific Northwest U.S. region.
- Rate Regulated: The Study includes investor-owned and Crown or municipally owned electrical utilities governed by a utility commission. There were no merchant generators and competitive energy retailers included in the peer group, as those companies can generally be expected to be structured differently, and are less likely to disclose the detailed data needed to complete a benchmarking analysis.

Those criteria resulted in a group of nine Canadian and five Pacific Northwest U.S. electric utilities for the FBC peer group. Concentric also analyzed whether there are appropriate subsets of utilities that can be used as a proxy for FBC. Our conclusion, however, was that further consolidation of the

5 Econometric benchmarking can be employed where multi-company "panel" data is available, and the objective of the study is to identify the effects of causal factors.

6 Data Envelopment Analysis ("DEA") can be employed where an objective of the benchmarking is to quantify the theoretical optimum.

peer groups was unnecessary. The reasons for that are twofold. First, as described further below, Concentric used peer group medians and quartiles for the purposes of benchmarking FBC. In a broad sense, therefore, the Study already amalgamated the companies in the peer groups. Second, Concentric had concerns with benchmarking FBC against an amalgamated proxy made up itself of only a few companies. The specific concern was one of sample size limitation, and the amalgamated benchmark being skewed by the anomalous results of one or two of the component companies.

A complete list of the Canadian and Pacific Northwest U.S. electric utilities included in the industry peer groups is provided in Figure 1.[7]

Figure 1: Peer Group Canadian and Pacific Northwest U.S. Electric Utilities

No.	Company Name	Ultimate Parent Company Name	State(s)/ Province of Operation
	Canadian Electric Utilities		
1	ATCO Electric Distribution	ATCO Ltd.	Alberta
2	Maritime Electric	Fortis Inc.	Prince Edward Island
3	Fortis Alberta	Fortis Inc.	Alberta
4	Newfoundland Power	Fortis Inc.	Newfoundland
5	ENMAX	ENMAX Corporation	Alberta
6	EPCOR	EPCOR Utilities Inc.	Alberta
7	Hydro Quebec Distribution	Hydro Quebec	Quebec
8	Hydro Ottawa	Hydro Ottawa Holding Inc.	Ontario
9	BC Hydro	BC Hydro	British Columbia
	Pacific Northwest U.S. Electric Utilities		
1	Avista Corporation	Avista Corp.[8]	Idaho, Montana, Washington
2	Idaho Power Co.	Idaho Power Co.	Idaho, Oregon
3	PacifiCorp	PacifiCorp	California, Idaho, Oregon, Utah, Washington, Wyoming
4	Portland General Electric Company	Portland General Electric Company	Oregon
5	Puget Sound Energy, Inc.	Puget Sound Energy, Inc.	Washington

C. Benchmarking Metrics

The Study focused on the following financial and non-financial benchmarking metrics. These metrics measure the utilities' financial efficiency, reliability, and customer service performance.

7 In total, Concentric requested data from 15 electric Canadian utilities, and received data from nine of those companies.

8 On July 19, 2017, Hydro One announced that it was acquiring Avista Corp. As of the date of this report, however, that transaction had not closed.

These metrics were chosen in consultation between the Company and stakeholders. In Concentric's opinion, this set of metrics provides for a reasonably comprehensive overview of FBC's relative performance on both a financial and a non-financial basis.

Figure 2: Description of Benchmarking Metrics

Metric	Description
OM&A expenses per customer, unit of throughput, employee, and kilometre of distribution line	OM&A per unit (*e.g.*, customers, output, employees, kilometre of distribution line, *etc.*) measures a company's financial efficiency in terms of the level of expenses it incurs per unit. In a capital-intensive industry, such as the utility industry, OM&A should also be considered together with fixed assets (*i.e.*, net plant), as a company's capitalization policy will impact the amount of costs that are recorded to OM&A versus capital.
Net plant per customer, employee, and kilometre of distribution line	Net plant per unit (*e.g.*, customers, employees, kilometre of distribution line, *etc.*) measures a company's financial efficiency in terms of its level of fixed assets. As described above, net plant per unit should be considered together with OM&A to provide a more complete view of a company's cost structure.
Energy delivered per customer	Energy delivered per customer provides descriptive information regarding a company's customer base and usage characteristics.
Energy delivered per employee	Energy delivered per employee provides information regarding the efficiency of a utility in providing service.
Employees per customer	Employees per customer provides further information regarding the efficiency of a utility in providing service.
Administrative and General ("A&G") expense per customer and volume	A&G per unit (*e.g.*, customers, output, *etc.*) measures the efficiency of a company's administrative and back office functions. In a benchmarking analysis, A&G should be considered together with the company's overall expense levels (*i.e.*, OM&A), because different companies may have different policies regarding the recording and reporting of A&G costs such as labour costs and benefits. Some companies may record those costs as A&G, while others may use overhead loading factors to reclassify those costs to operations.
Customer care costs per customer	Customer care costs per unit provide information both about the overall scope of a company's customer care function, as well as the efficiency of that function.
Financing costs per customer	Financing costs per customer provide information regarding a company's cost of capital. In a capital-intensive industry, such as the utility industry, financing costs will tend to correlate with overall fixed asset/net plant figures.
Emergency response time	This measure is calculated as the percent of calls responded to within two hours and measures the responsive efficiency of the utility.

Metric	Description
SAIDI and SAIFI	The System Average Interruption Duration Index ("SAIDI") is the average outage duration per customer, calculated as the total duration of customer interruptions divided by the total number of customers. The System Average Interruption Frequency Index ("SAIFI") is the average number of outages per customer, calculated as the total number of customer interruptions divided by the total number of customers. The SAIDI and SAIFI metrics measure system reliability. Certain outages are excluded from SAIDI and SAIFI depending on defined criteria.
Generator forced outage rate ("GFOR")	This measure is the percentage of time in one year that a company's generating units experienced forced outage rates compared to the amount of time these units could have operated without a forced outage. It measures the reliability of a company's generating fleet.
Telephone response and abandonment rates	Telephone service factor ("TSF") –non-emergency, first contact resolution ("FCR"), and telephone abandonment rate all measure customer service via call centers. TSF is the number of calls answered within 30 seconds divided by the number of calls received. FCR is the percent of customers who achieved call resolution within one call. The telephone abandonment rate is equal to the total number of abandoned calls divided by the total number of answered calls plus abandoned calls.
Demand side management ("DSM") expenditures	DSM expenditures per customer measures each company's expenditures on DSM programs, both with incentives and without incentives. Non-incentive expenditures include indirect costs associated with the DSM program (*e.g.*, program administration, communication and outreach, research and evaluation of the program, *etc.*). The level of DSM expenditures is dependent on the availability of regulatory mechanisms for cost recovery and the utility's efficiency in deploying these programs.

D. Data Sources

The Study is based on data that was compiled from publicly available sources and commercially available databases for the U.S. utilities. For the Canadian companies, there is insufficient publicly available information that is available on a consistent basis. Therefore, Concentric sent data surveys to Canadian utilities requesting the data necessary for the Study. In total, Concentric requested data from 15 electric utilities, and received data from nine of those companies. Because the majority of the data that was provided was not otherwise publicly available, the Canadian utilities provided their information on a confidential basis. Concentric necessarily had access to the names and company-specific data for each utility, but FBC did not have such access (except as provided herein). As such, the names of the utilities are not linked with the results in the Study so as to preserve that confidentiality.

FBC's data is based primarily on data provided by FBC for 2012 through 2017. Data provided by the Company includes the underlying financial and operational data necessary to calculate the benchmarking metrics (*i.e.*, O&M expenses, net plant, customers, employees, kilometres of distribution lines, and volumes, as well as the reliability and customer service metrics).

1. Canadian Peer Group

Because the Canadian data was not available as one data set or from consistent, publicly-filed financial statements, Concentric took steps to ensure that the data collected through our survey process was consistently-presented and provided a reasonable and adequate basis upon which to compare FBC. Those steps included: (1) sending to each survey respondent a template to be completed that was organized consistently with the benchmarking metrics, and with descriptions of each metric, so as to limit differences in interpretation; (2) after receiving responses, carefully reviewing the data for anomalous results and inconsistencies; (3) through an iterative process, working with each surveyed company through a series of follow-up communications to resolve questions and data classification/presentation issues. The survey template is provided in Appendix A to the Study, and a more detailed description of the data gathering and validation process is provided in Appendix B.

Concentric also relied on data provided by the Canadian Electricity Association to compare FBC's reliability performance against other Canadian companies.

2. Pacific Northwest U.S. Peer Group

For the Study, Concentric primarily relied on data compiled from annual reports filed by the individual operating utilities with their federal or state regulatory commissions.[9] Once compiled, the database of

[9] Concentric primarily relied on data from the annual reports as provided through the SNLxL database.

data was checked for completeness and consistency. Data was gathered and presented at the individual operating subsidiary level, not the holding company level.

V. INDUSTRY BENCHMARKING RESULTS

A. Overview

This section presents the results of the benchmarking analyses. First, an overview of descriptive metrics (*e.g.*, percentage of plant by function and number of customers) is provided for FBC and each of the peer group companies. Second, an analysis of FBC's performance on a stand-alone basis is provided. Third, a comparison of FBC's relative performance to that of the peer groups is provided.

FBC's performance compared to other utilities is heavily reliant on the composition of the proxy group. As such, it is important to focus not only on those groupings of companies that are most comparable to FBC, but also on those data that provide a comparison of utilities on a similar basis. As discussed herein, Concentric focused on those cost segments (*i.e.*, distribution costs) that both maximized the number of peer companies included in the analysis and put the peer companies on as equal a footing as possible.

For those metrics where sufficient peer group data was available, each benchmarking figure presents five main data points: (1) FBC's result for each metric, per year; (2) the Canadian peer group median (including FBC) result, per year; (3) the Canadian peer group median (excluding FBC) result, per year; (4) a shaded region that provides the range between the first and third quartile performance in the Canadian peer group (including FBC) (denoted as "Canadian Q1-Q3" in each figure); and (5) the Pacific Northwest U.S. peer group median, per year. Because Concentric is benchmarking costs, first quartile performance represents the lower quartile. For those metrics for which insufficient peer group data was available (*i.e.*, there was data available from less than five peer group companies, and thus quartiles would be less meaningful), the figures do not provide the shaded region with the range between the first and third quartile performance for the Canadian companies.

B. Descriptive Metrics

As noted previously, FBC's performance is compared to nine Canadian and five Pacific Northwest U.S. electric utilities that were chosen based on a number of selection criteria designed to reflect FBC's operating profile and provide a broad perspective for industry comparisons. In order to provide context and background on the peer group, the following sections compare FBC's operational profile to the peer group.

1. Operational Profile

The figure below provides the operational profile of the companies in the peer group in terms of the percentage of net plant dedicated to distribution, transmission, generation, and other operations.

Figure 3: Electric Company Functional Mix

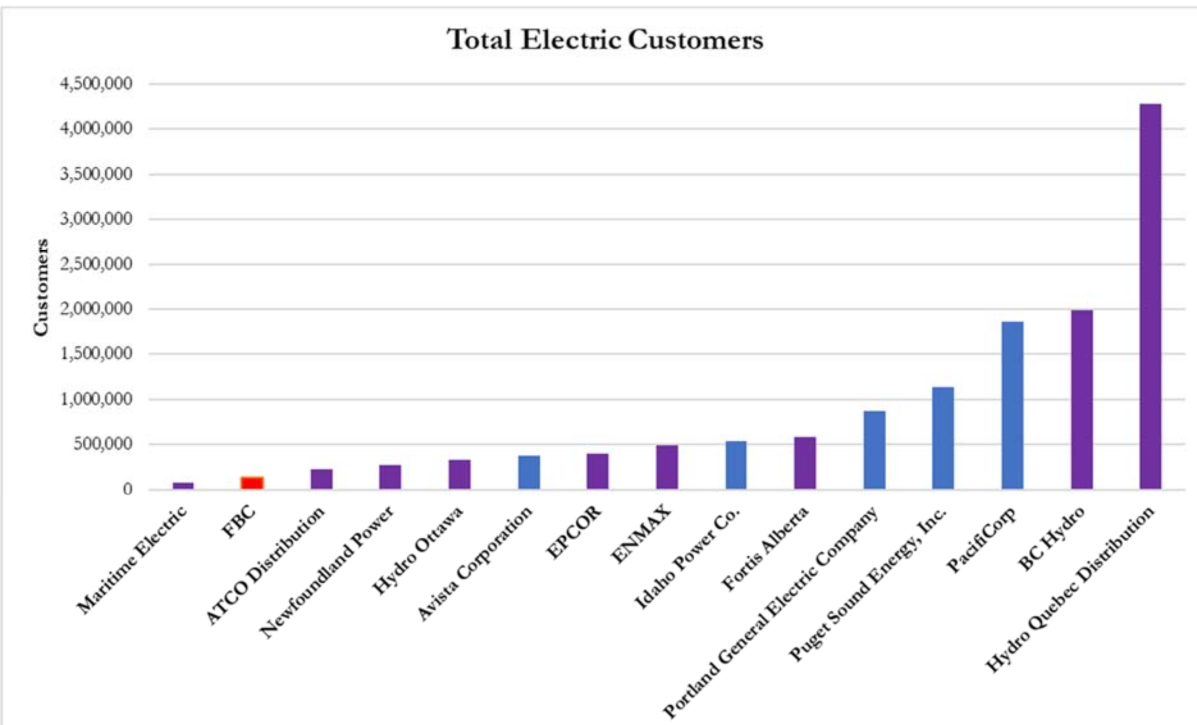
Company	Distribution	Transmission	Generation	Other
FBC	**54%**	**25%**	**13%**	**8%**
Company A	22%	25%	43%	9%
Company B	26%	6%	52%	16%
Company C	26%	34%	33%	7%
Company D	30%	22%	40%	9%
Company E	40%	17%	38%	5%
Company F	43%	20%	32%	6%
Company G	54%	23%	13%	10%
Company H	58%	36%	0%	6%
Company I	61%	19%	14%	7%
Company J	74%	26%	0%	0%
Company K	82%	0%	0%	18%
Company L	88%	0%	0%	12%
Company M	99%	0%	0%	1%
Company N	100%	0%	0%	0%
Average	**57%**	**17%**	**19%**	**8%**

As shown in the figure above, the companies in the peer group have different mixes of functions within their operational profiles. This can lead to skewed results if certain companies have a greater proportion of their operations in traditionally higher cost functions or functions that are more subject to cost variation (*e.g.*, electric generation). Concentric controlled for that risk in the Study by focusing on the distribution-only segment of the peer group companies (plus total A&G costs) and excluding generation and transmission O&M from certain of the financial analyses.

2. Customer Profile

As of 2017 (*i.e.*, the last year in the period studied), FBC served approximately 135,000 electric customers.[10] In terms of utility size, FBC is the second smallest Canadian utility among the peer group and second smallest overall among the Canadian and Pacific Northwest U.S. peer groups. The average and median number of customers in the electric peer group are approximately 905,000 and 495,000, respectively, as compared to FBC's approximately 135,000 customers. The figures below show the total electric customers as of the most recent data available for FBC (in red) and each of the electric utilities in the peer group (with the Canadian utilities in purple and the Pacific Northwest U.S. utilities in blue). These data suggest that to the extent scale economies are operative, FBC would be expected to be among the least efficient of its electric peers.

Figure 4: Peer Group Electric Customers



3. System Throughput

The figures below show the most recently available total electric sales for FBC and each of the electric utilities in the peer groups, as well as the volumes sold per customer. As illustrated, FBC is the second

[10] Excludes indirect customers.

smallest Canadian utility among the peer group and second smallest overall among the Canadian and Pacific Northwest U.S. peer groups. The average and median volumes in the electric group are approximately 28.7 million megawatt hours ("MWh") and 12.0 million MWh, respectively, as compared to FBC's approximately 3.3 million MWh.

Figure 6 demonstrates that FBC is near the median of the Canadian peer group in terms of volumes per customer, indicating general comparability to the Canadian utilities in the Study in terms of customer profile and usage.

Figure 5: Peer Group Electric Volumes

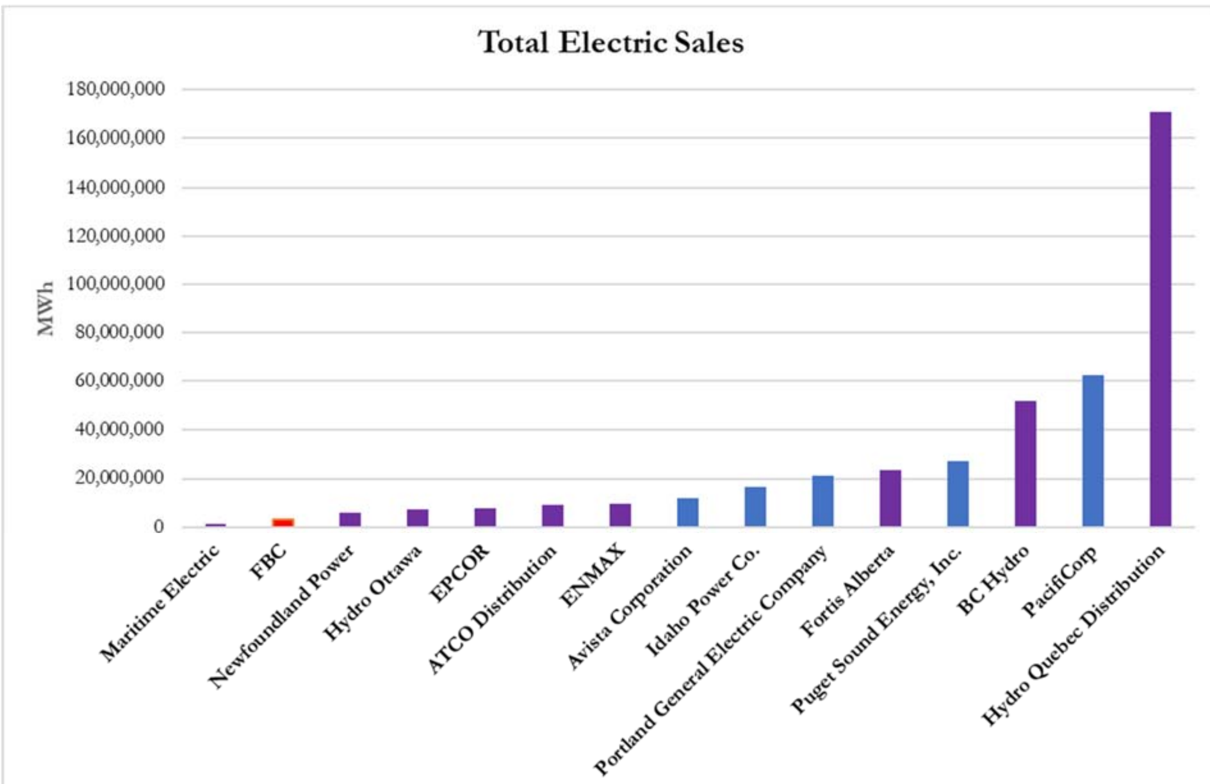
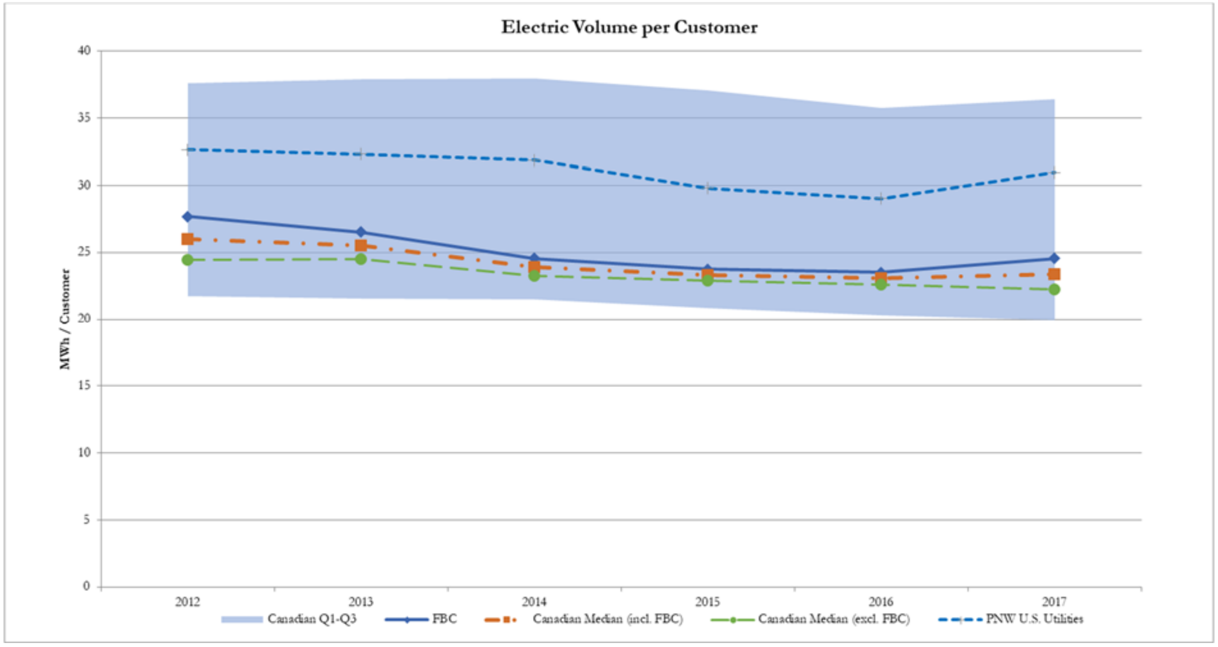


Figure 6: Electricity Delivered per Customer



C. Stand-Alone Financial Analysis

In terms of analyzing FBC's performance on an isolated basis, the Company's OM&A and net plant increased over the period studied on a nominal basis (five-year compound annual growth rates ("CAGRs") of 2.08% and 2.95%, respectively), and increased by less than 1.00% year-over-year on a real basis, based on a five-year average annual increase in the Consumer Price Index of 1.39%.[11] The following figures illustrate those trends.

11 Source: Statistics Canada. Table 18-10-0005-01 Consumer Price Index, annual average, not seasonally adjusted.

Figure 7: FBC Total O&M Expense ($000s, nominal)

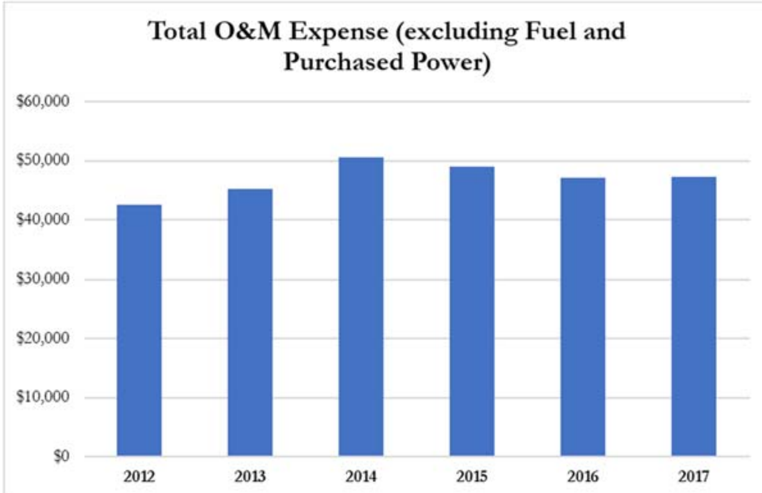
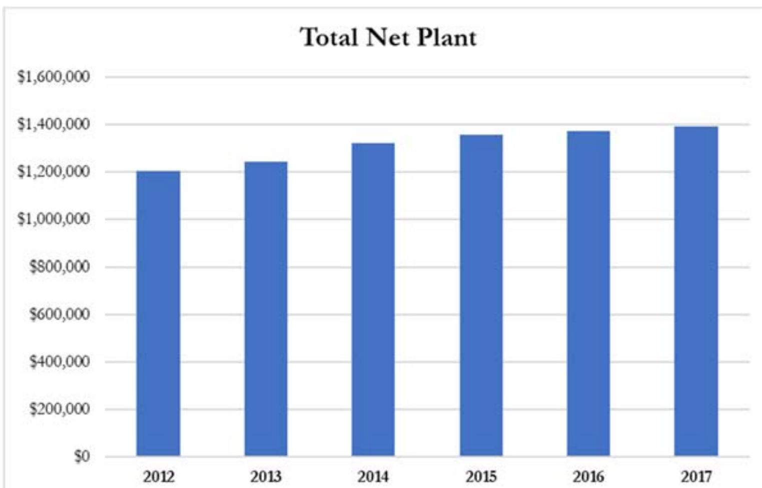


Figure 8: FBC Total Net Plant ($000s, nominal)



D. Benchmarking and Trend Analysis

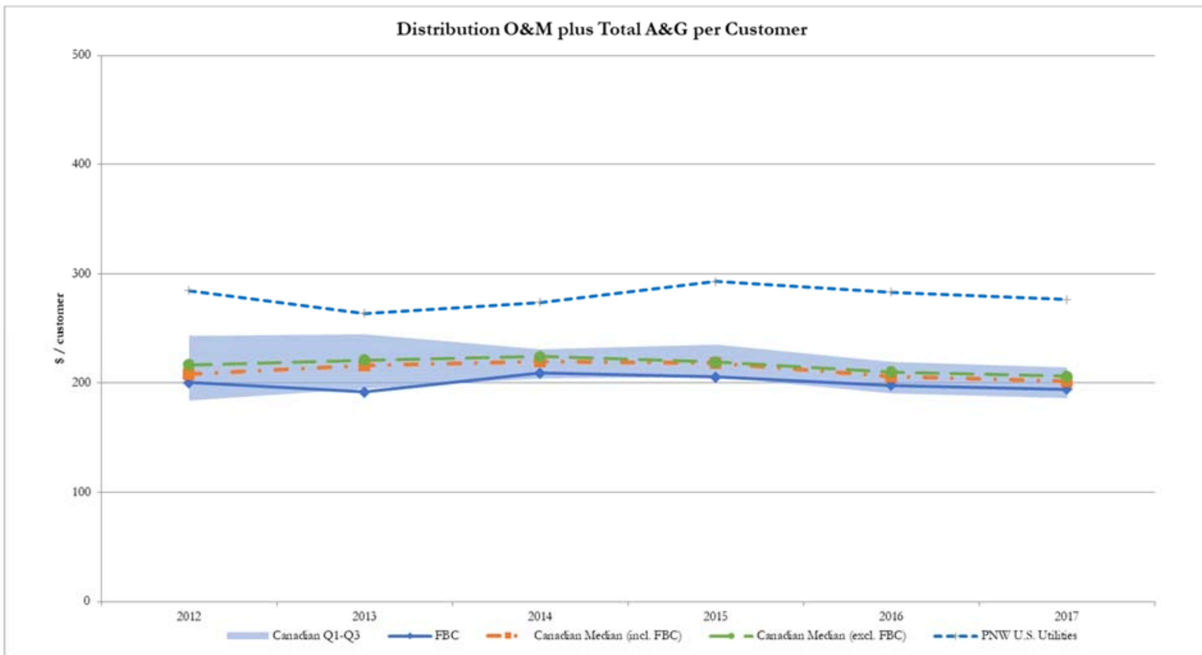
The following sections summarize the results of the benchmarking and trend analysis that compares FBC's performance against the electric peer group across a number of financial and operational metrics. FBC's electric performance is benchmarked against the Canadian and Pacific Northwest U.S. peer groups over the period 2012 through 2017.

<u>Financial Metrics</u>

For FBC, Concentric's initial observation is that the distribution-only (plus total A&G, excluding customer care) segment provides the most meaningful benchmark, because of significant differences between the scope of proxy companies' generation and transmission facilities (as discussed above), as well as the provision of customer care services.[12] Specifically, the Alberta utilities in the sample do not provide certain customer care services (*e.g.*, billing, collections) to end-use customers. Use of the distribution O&M plus total A&G cost segment also ensures the inclusion of the greatest number of Canadian peer group companies, providing for more reliable benchmarking results. For those reasons, the most comparable cost segment across the peer group companies excludes power production, transmission, and customer care. Discussions of each individual metric are provided below.

1. Distribution O&M and Total A&G

Figure 9: Distribution O&M and Total A&G/Customer



12 In performing this analysis, Concentric did not make any adjustment to, or otherwise allocate, A&G to the various utility functions, but rather used total A&G expense for benchmarking purposes. Allocation of A&G to the generation and transmission functions, such as might be done under a fully allocated cost-of-service study, would reduce the total expense analyzed for those companies, including FBC, with generation and transmission functions.

Figure 10: Distribution O&M and Total A&G/MWh

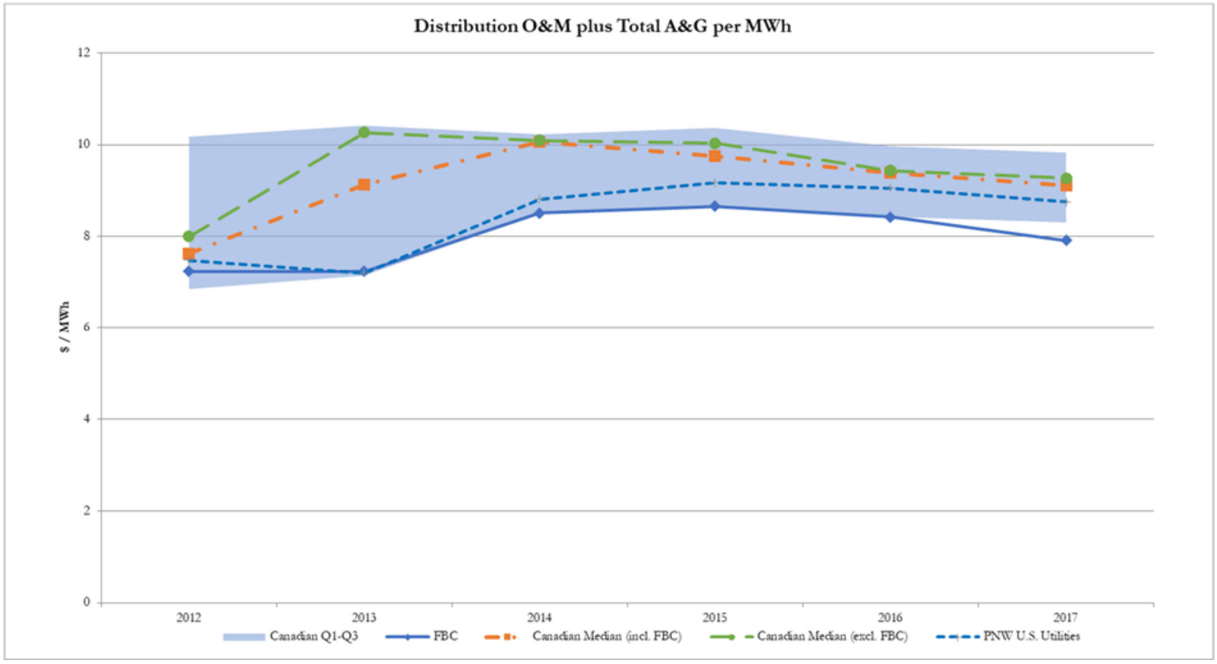


Figure 11: Distribution O&M and Total A&G/Employee

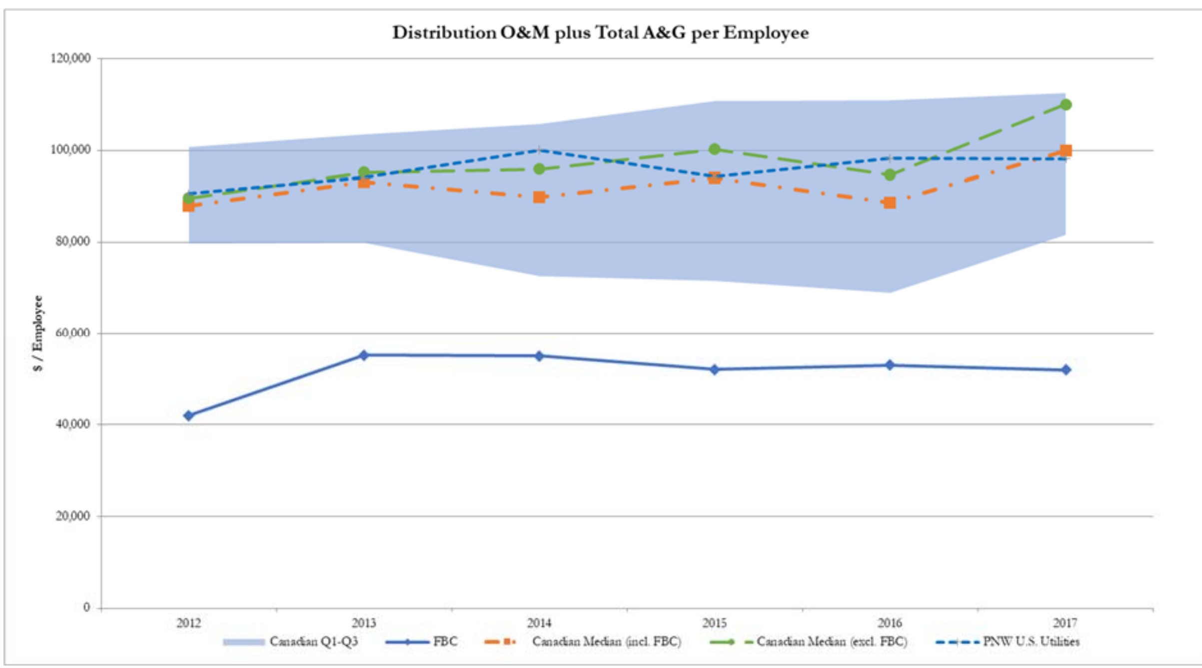
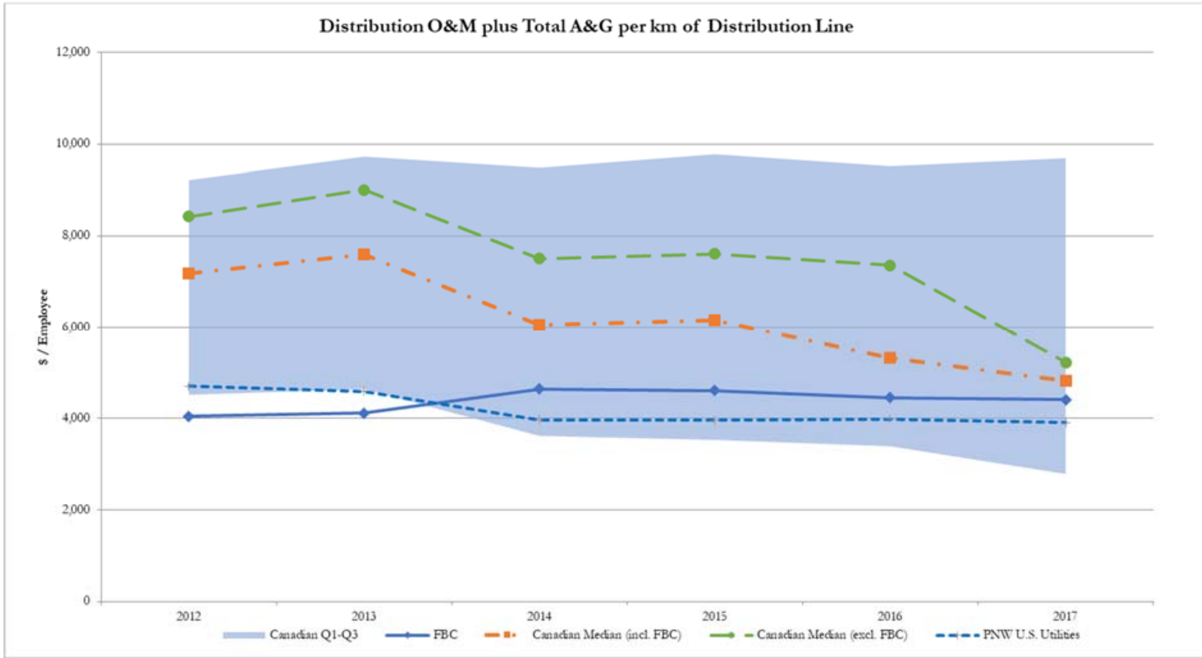


Figure 12: Distribution O&M and Total A&G/Kilometre of Distribution Line



Based on the distribution O&M and total A&G cost segment, FBC compares favorably (*i.e.*, below the median) to the Canadian medians (both including and excluding FBC) and Pacific Northwest U.S. peer group median on a dollar-per-customer, dollar-per-MWh, and dollar-per-employee basis. On a dollar-per-kilometre basis, FBC is below both Canadian medians, but above the Pacific Northwest U.S. median in the years 2014 through 2017. For the distribution O&M and total A&G-per-customer metric, FBC and the peer groups had similar five-year nominal CAGRs (*i.e.,* (0.62)%, (0.66)%, (0.98%), and (0.60)% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively). While the Pacific Northwest U.S. peer group has companies with distribution O&M and total A&G-per-customer that fall below the Canadian peer group median, that group is less tightly clustered than the Canadian peer group, and there are two companies within the U.S. group that drive the median above the Canadian range and median.

The growth rates for distribution O&M and total A&G-per-MWh were 1.80%, 3.64%, 3.00%, and 3.19% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively. The medians for the three peer groups and FBC's distribution O&M and total A&G-per-MWh were relatively consistent over the Study period. The growth rates for distribution O&M and total A&G-per-employee were 4.34%, 2.59%, 4.18%, and 1.63% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively. Finally, the growth rates for distribution O&M and total A&G-per-kilometre of distribution line were 1.74%, (7.70%), (9.11%), and (3.65%) for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively. The drop in medians for the Canadian peer groups for 2017 is driven by missing data for one of the Canadian companies for that year. It is worthy to note that despite FBC's small size relative to its peers, it is not evidenced in higher O&M costs on these measures.

2. Net Plant

Figure 13: Net Distribution Plant/Customer

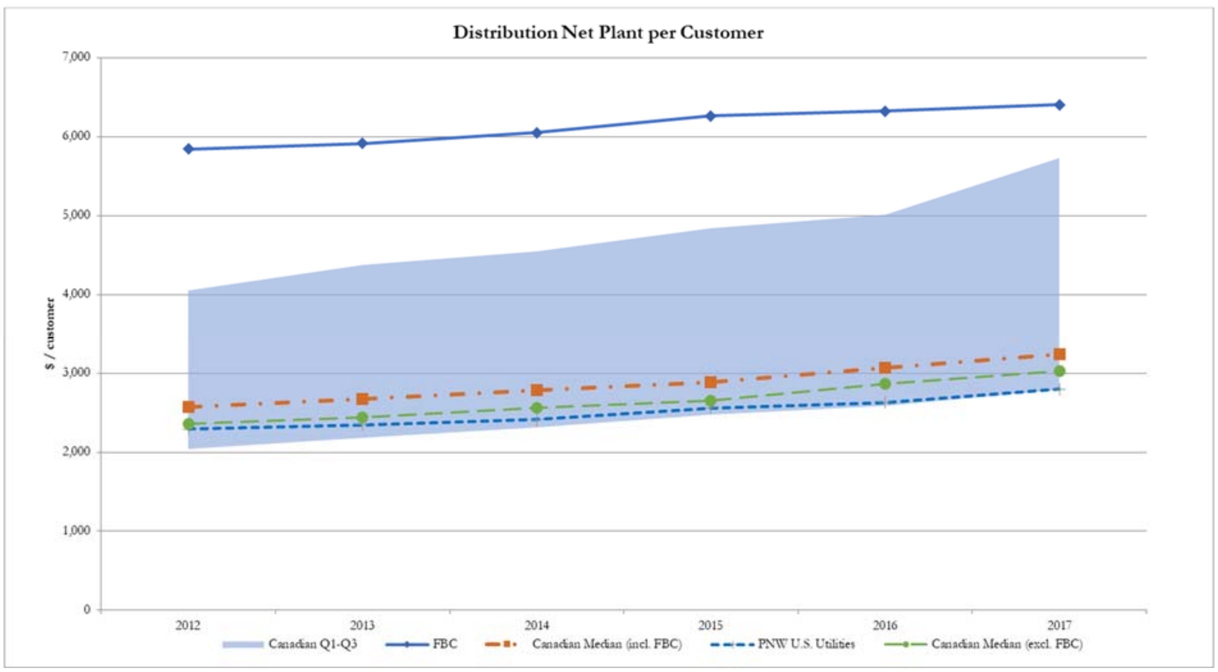


Figure 14: Net Distribution Plant/Employee

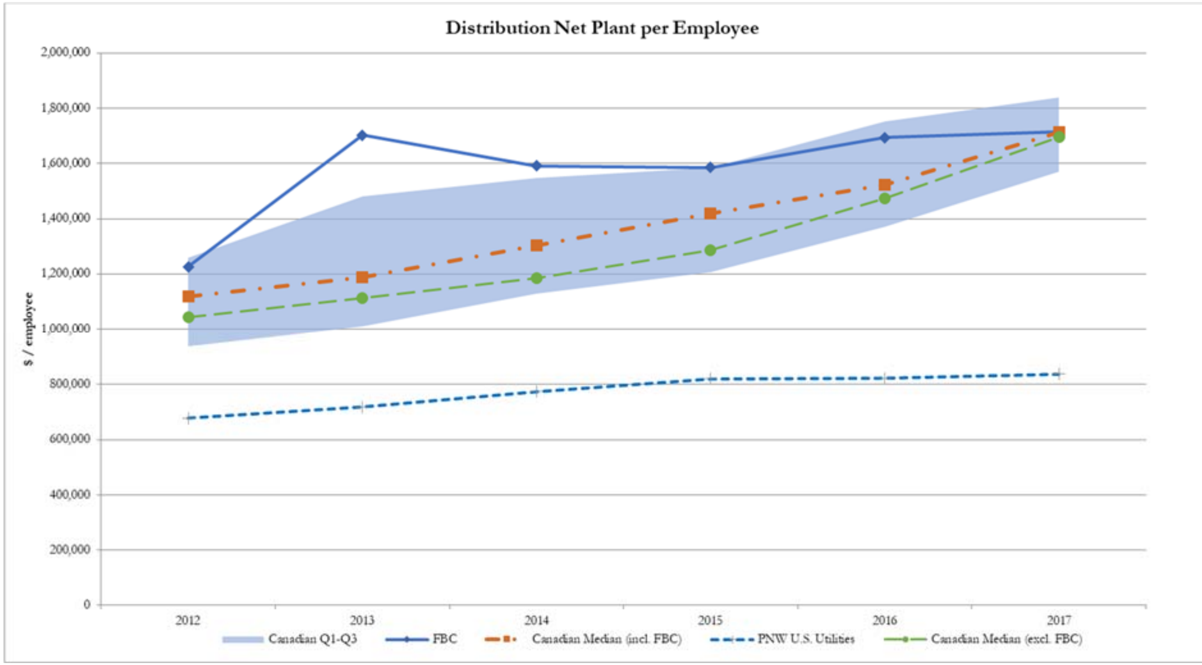
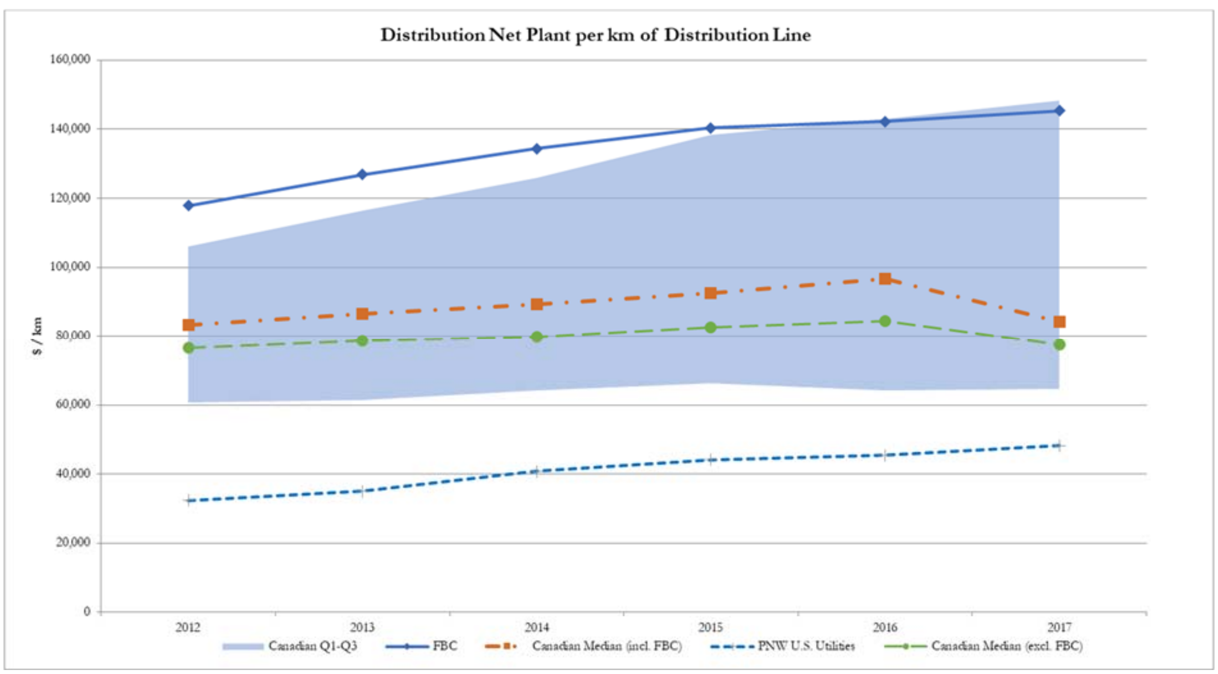


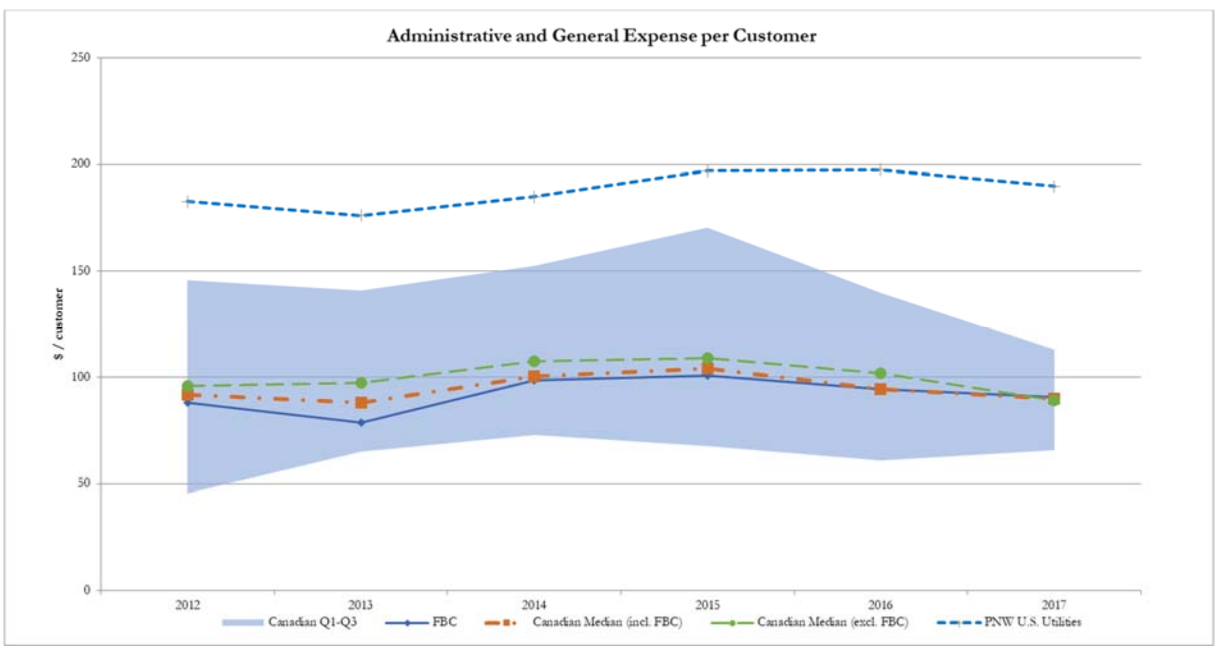
Figure 15: Net Distribution Plant/Kilometre of Distribution Line



Compared to the Canadian and Pacific Northwest U.S. utilities in the peer groups (both including and excluding FBC), FBC was well above the median on a net plant-per-customer basis and net plant-per-kilometre of distribution lines basis for the all years in the study period, and above the median in all years except 2017 (where it was at the median) on a net plant-per-employee basis. FBC went through a period of significant capital expenditures from 2005 through 2012, resulting in an elevated level of gross plant that has not been significantly depreciated.[13] Net plant per customer increased for FBC and the peer groups over the study period (nominal CAGRs of 1.85%, 4.73%, 5.07% and 4.08% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively), although at a slower rate for FBC than the peer groups. Net plant per employee and per kilometre of distribution lines also increased for FBC over the study period. It should be noted that, for the net plant per kilometre of distribution lines metric, the decrease in the Canadian peer groups' medians in 2017 is driven by one peer group company with higher net plant per kilometre results in other years being excluded from 2017 due to a lack of data. The width of the ranges of the Canadian peer group for both the net plant per customer metric and net plant per kilometre of distribution lines metric is driven by a few companies other than FBC that also have relatively high net plant per-unit. Unlike OM&A, FBC's net plant on a per-unit basis may also be impacted by its lack of scale compared to its peers.

3. A&G Expense

Figure 16: Total A&G/Customer



13 For example, in its 2012 Integrated System Plan, Volume 1 (at 1), FBC stated, "Since 2005, FortisBC has invested approximately $700 million in new or upgraded generation, transmission/distribution and general plant infrastructure. Much of the transmission and distribution networks infrastructure, in particular, was being driven by customer and associated load growth."

Figure 17: Total A&G/MWh

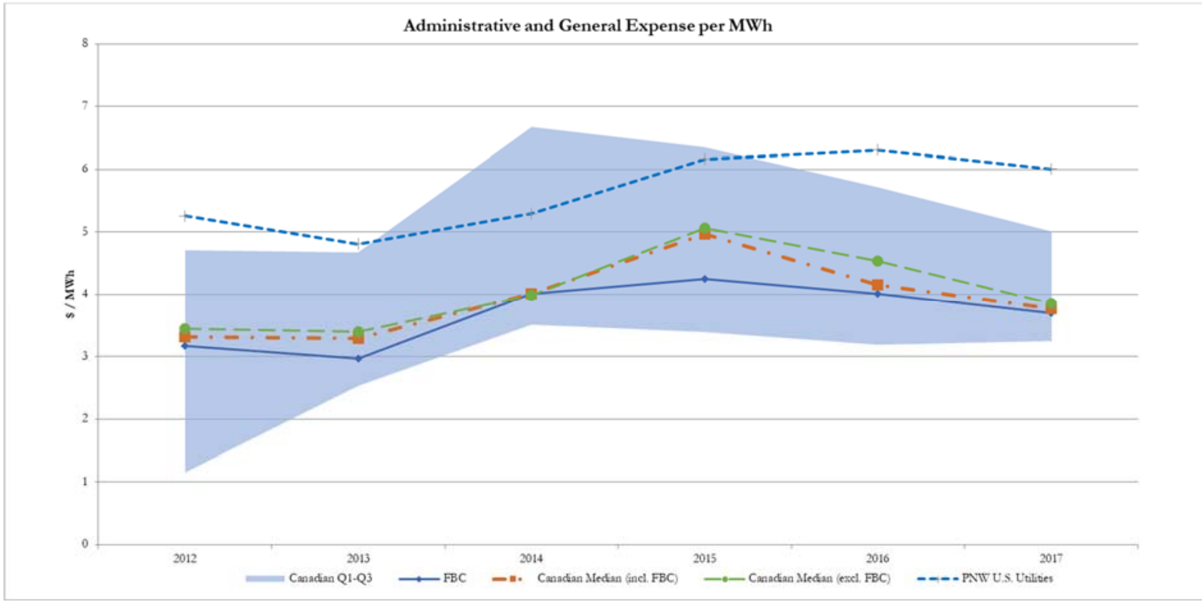


Figure 18: Electricity Delivered per Employee

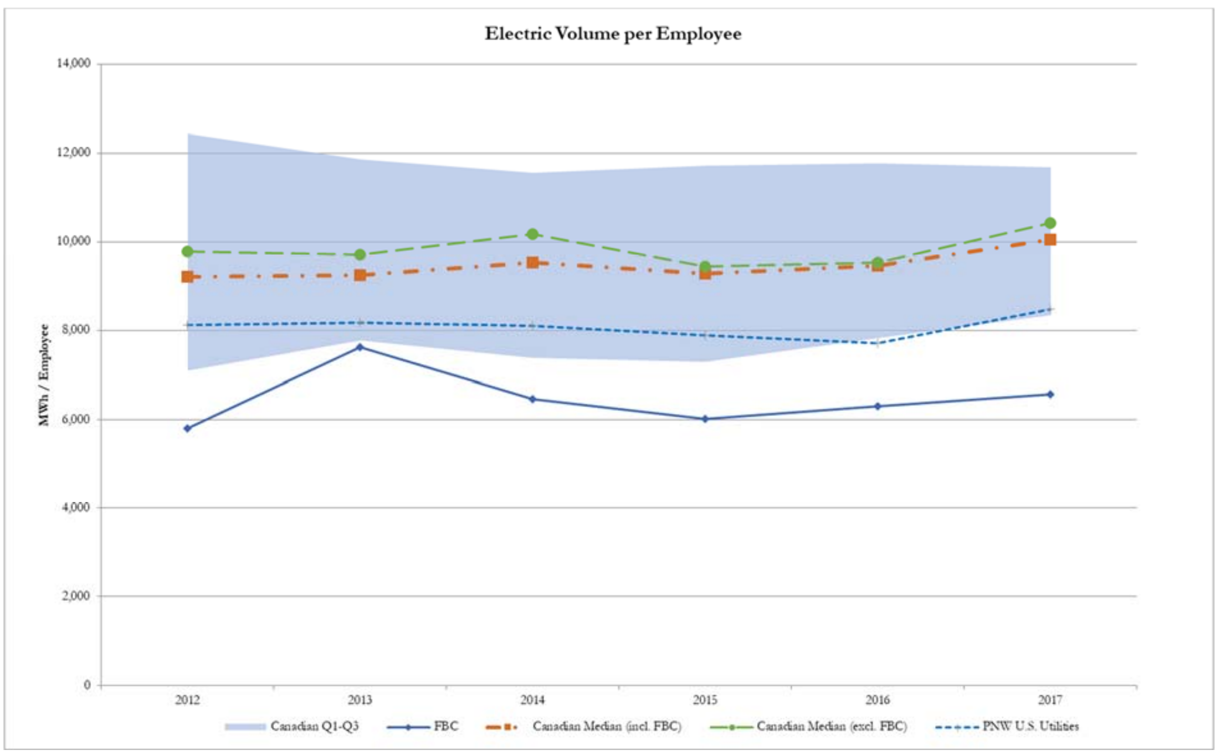
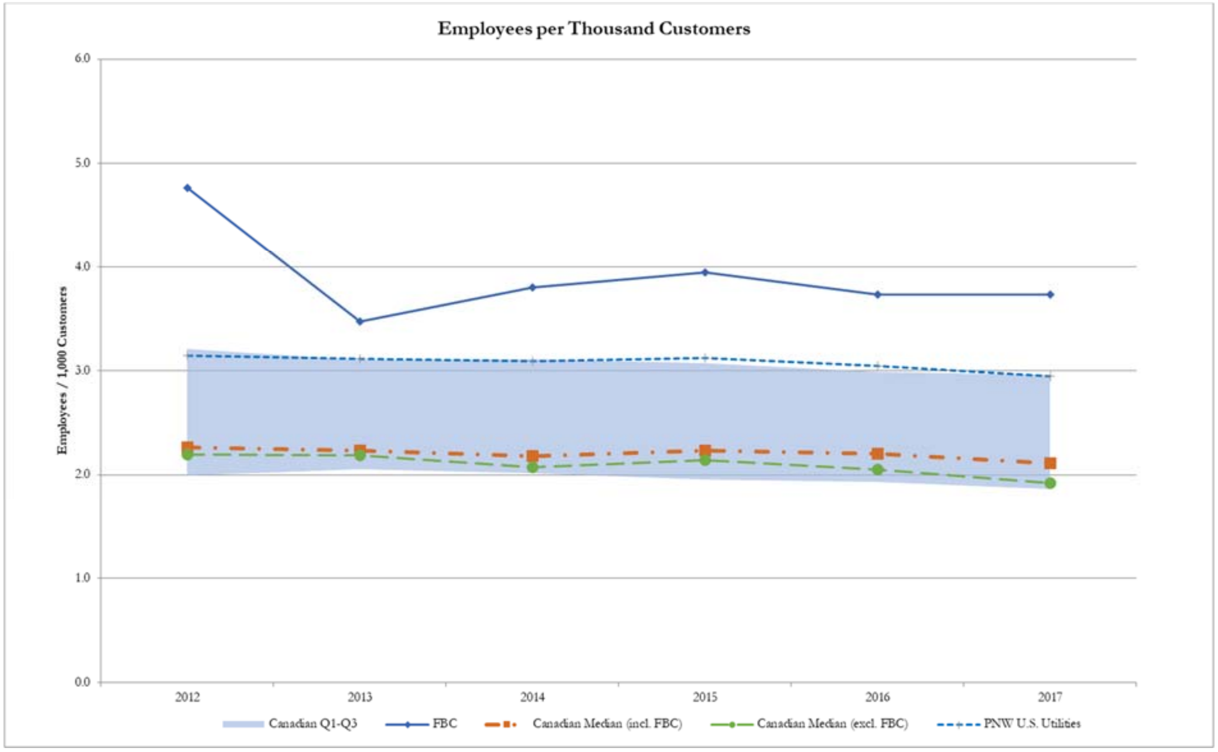


Figure 19: Employees per Thousand Customers

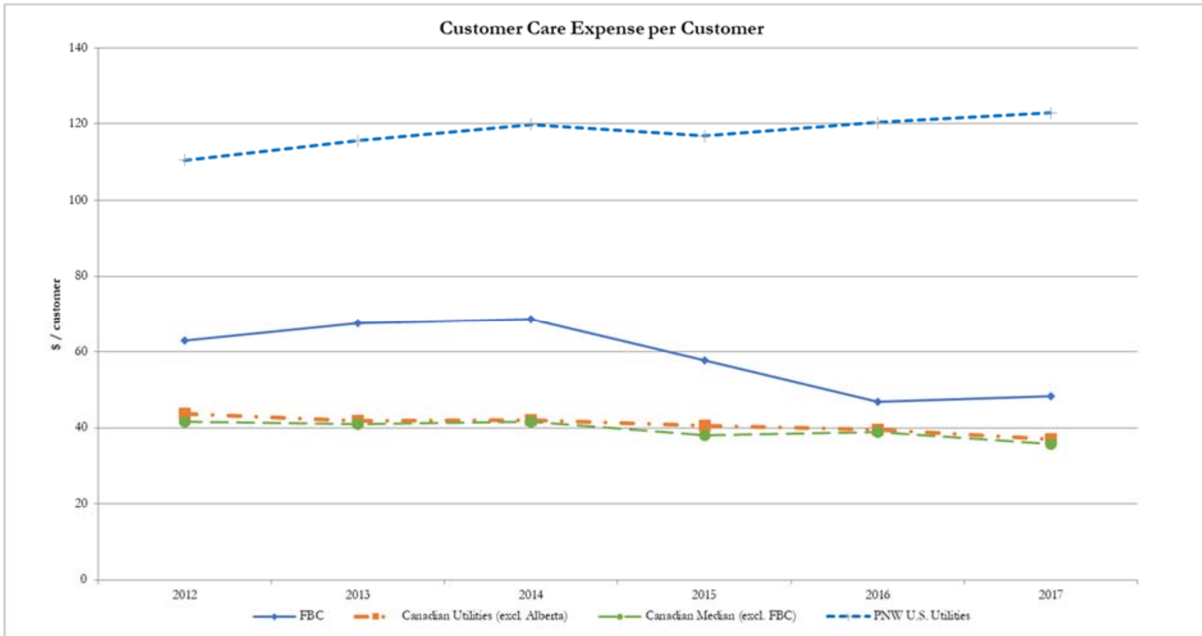


Over the period of study, FBC was below the Pacific Northwest U.S. peer group median, and approximated the Canadian peer group median (both including and excluding FBC) on both an A&G expense per customer basis and a per MWh basis. FBC's nominal growth rates for A&G expense were 0.61% and 3.06% on a per-customer and per-MWh basis, respectively.

The figures above showing electric volume per employee and employees per thousand customers also provide information regarding the efficiency of the Company's workforce. While most companies in the Canadian peer group, including FBC, provided less than 12,000 MWh per employee over the Study period, two companies provided in excess of 20,000 MWh per employee, resulting in the relatively wide quartile range depicted in the figure. In addition, while most Canadian peer group companies had 2.5 employees or less per 1,000 customers, three of the companies (including FBC) had in excess of three employees per thousand customers. The Company provided less volume per employee than the Canadian peer group median over the period studied and is above the Canadian peer group medians in terms of employees per thousand customers. Those results, however, did not appear to come at an overall higher cost, based on the OM&A results discussed above. Further, volume-based metrics, such as volume per employee, can be driven by the customer mix of a utility (and the building stock, weather and customer usage characteristics) whereby companies with a higher percentage of commercial and industrial customers (and thus a lower percentage of residential customers) will have more volume delivered per employee, and visa-versa.

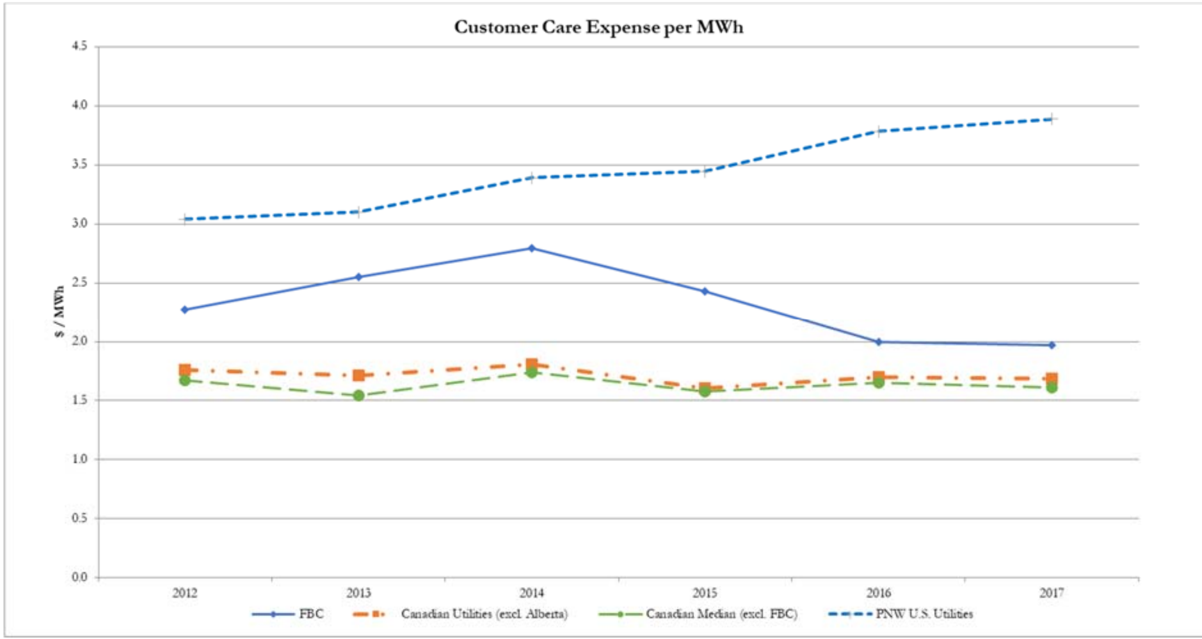
4. Customer Care Expense[14]

Figure 20: Customer Care Expense/Customer



14 As mentioned earlier, since Alberta utilities do not provide certain customer care services (*e.g.*, billing, collections) to end-use customers, they are excluded from the customer care expense comparisons.

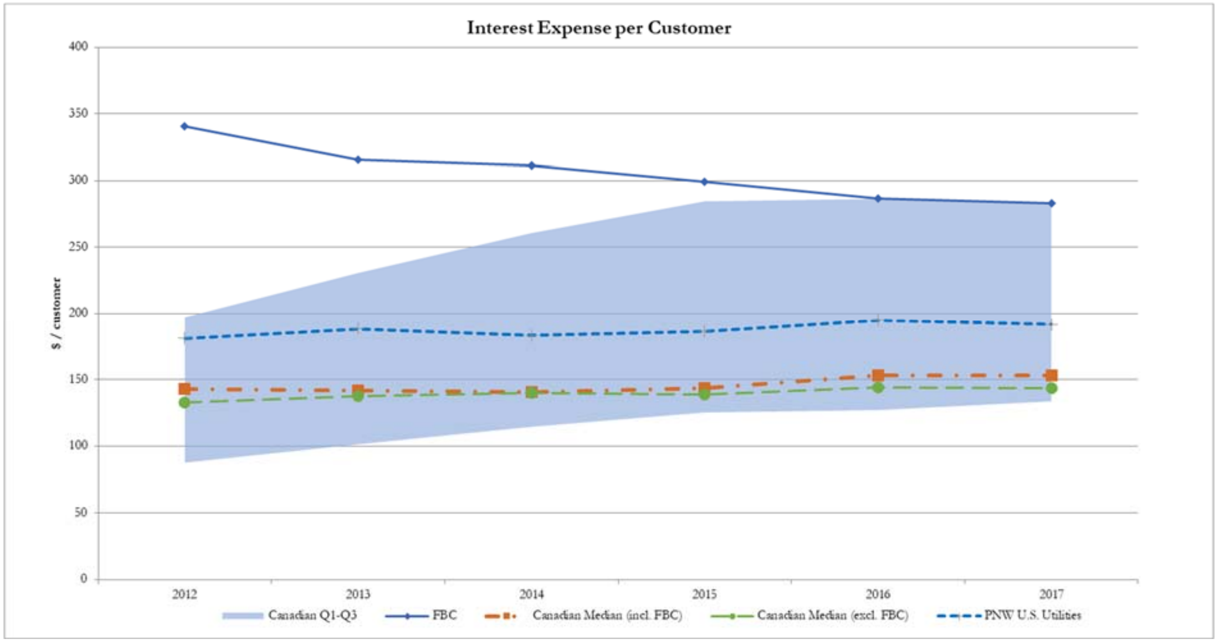
Figure 21: Customer Care Expense/MWh



In 2012 (*i.e.*, the beginning of the period studied), FBC's customer care expense per customer and per MWh fell in between the Pacific Northwest U.S. and Canadian peer group medians (both including and excluding FBC). By 2016 to 2017, FBC was just above the Canadian peer group median (both including and excluding FBC) on this metric, and remained well below the Pacific Northwest U.S. peer group median.

5. Interest Expense

Figure 22: Interest Expense/Customer



Financing costs on a dollar-per-customer basis are related to a utility's overall level of plant investment. As discussed previously, FBC's net plant was well above that of the peer group medians. As such, FBC's interest costs per customer was also greater than the Canadian (both including and excluding FBC) and Pacific Northwest U.S. peer group medians over the period studied, although it fell over that period. FBC's interest expense per customer experienced negative growth from 2012 to 2017, while that of the peer groups increased (nominal CAGRs of (3.63)%, 1.38%, 1.63%, and 1.14% for FBC, the Canadian peer group median including FBC, the Canadian peer group median excluding FBC, and the Pacific Northwest U.S. peer group median, respectively). That is largely driven by a slower growth in net plant for FBC as compared to the growth rate of the companies in the peer groups, as discussed earlier in this report. The width of the range of interest costs per customer is driven by three companies (including FBC) that had interest expense per customer in the $300-per-customer range over the period studied, compared to the other companies that were more consistently between $150 to $200 in interest costs per customer. It is important to note that while Concentric did not do a direct comparison of the capital structures at each peer group company, interest expense is driven not only by a utility's cost of debt, but also by the relative proportion of its rate base that is financed with debt (*i.e.*, its capital structure).

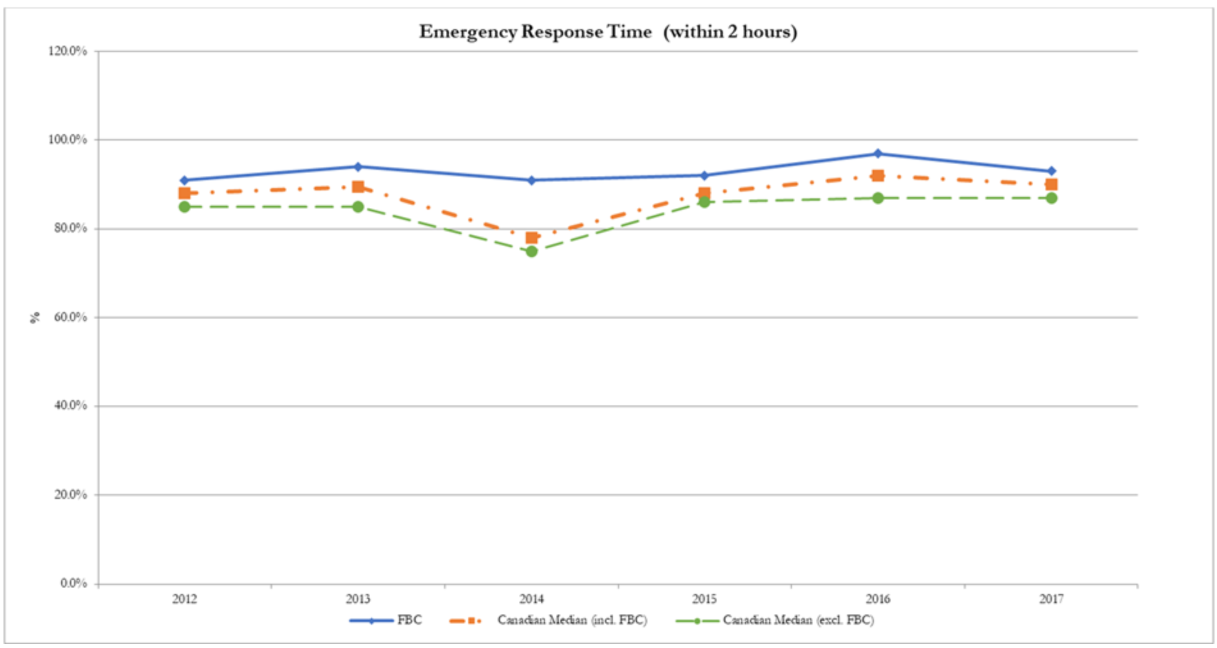
Reliability and Customer Service Metrics

The Study included a number of reliability and customer service metrics, including emergency response time, SAIDI/ SAIFI, various call center related metrics, GFOR, and DSM expenditures. These metrics can be viewed either in isolation or in conjunction with the financial metrics to provide information regarding the service level provided given the studied companies' cost levels.

Further, the RFP for the Study requested that metrics that can be used to evaluate utilities' capabilities to adapt to evolving industry dynamics and societal needs be considered. In Concentric's view, the metrics discussed in this section serve that purpose, as they not only measure reliability and customer service, which are of paramount importance to customers, but they also measure items related to changing industry dynamics, such as DSM programs.

1. Emergency Response Time

Figure 23: Emergency Response Time



Emergency response time measures the percent of emergency calls responded to within two hours. FBC performed above the Canadian peer group medians (both including and excluding FBC) in each year of the study period. In 2014, FBC's emergency response time declined slightly compared to the preceding and following years. The peer group's median performance, however, declined at a greater rate than FBC's did. That peer group decline was driven by one peer group company that had substantially below average results compared to its emergency response time in other years. FBC's emergency response time was at or above its performance-based ratemaking benchmark of 93% for the years 2013, 2016 and 2017. Data was unavailable for the Pacific Northwest U.S. peer group.

2. SAIDI/SAIFI

Figure 24: SAIDI

Figure 25: Canadian Electric Association Industry Average – SAIDI

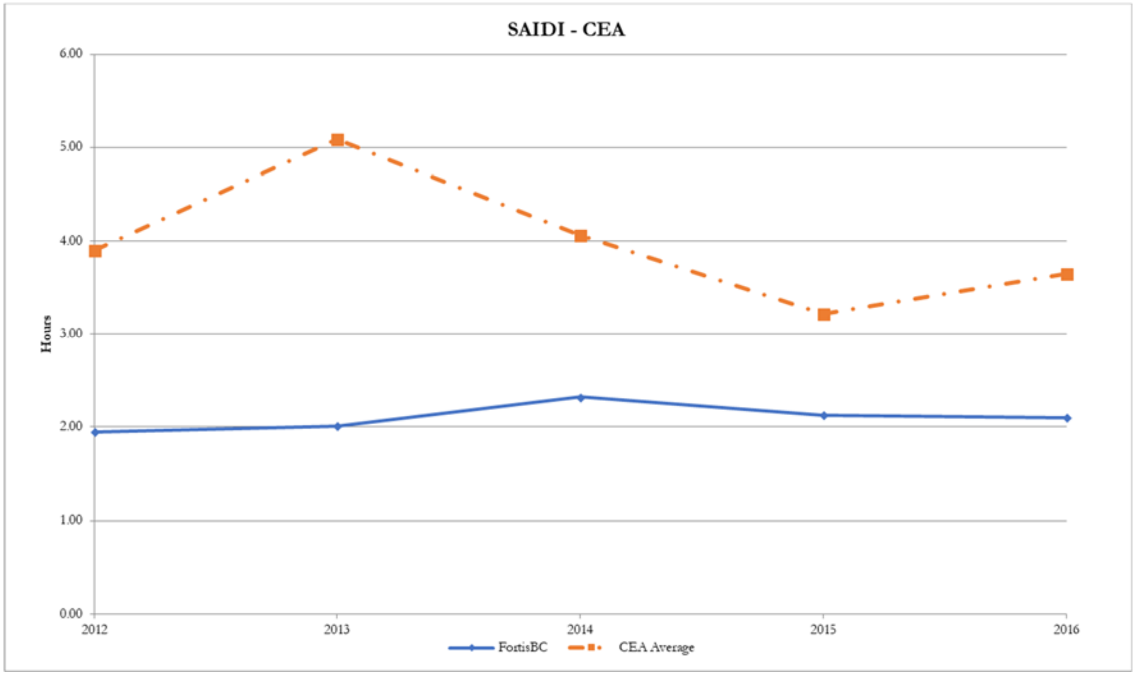


Figure 26: SAIFI

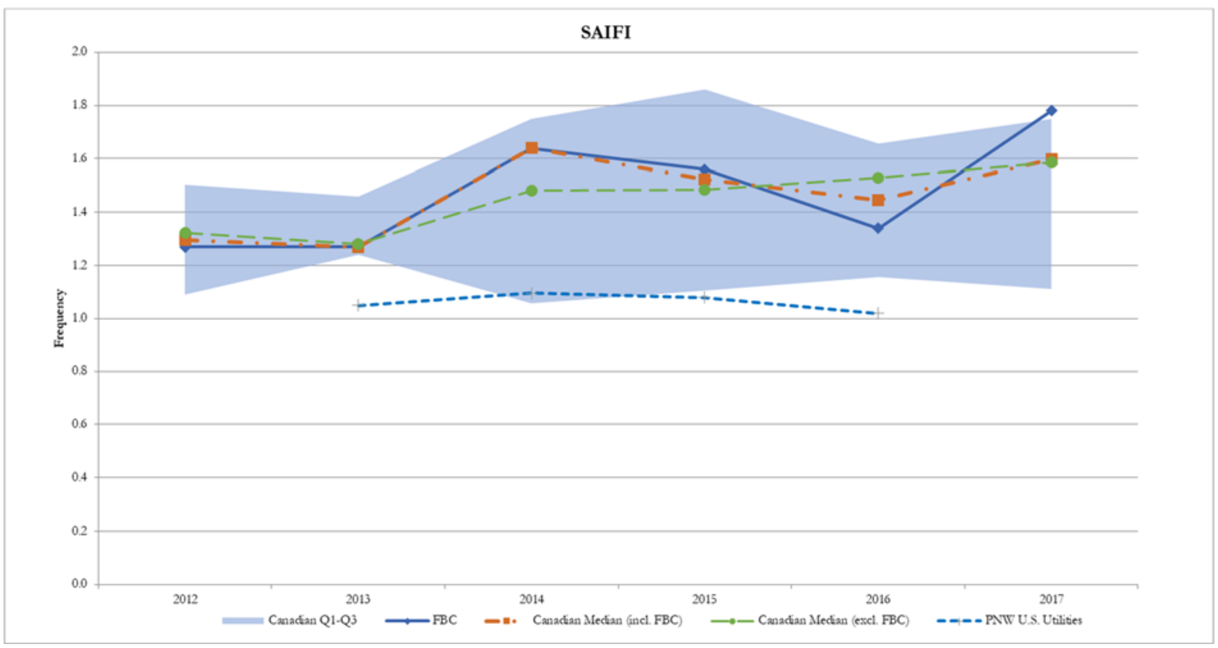
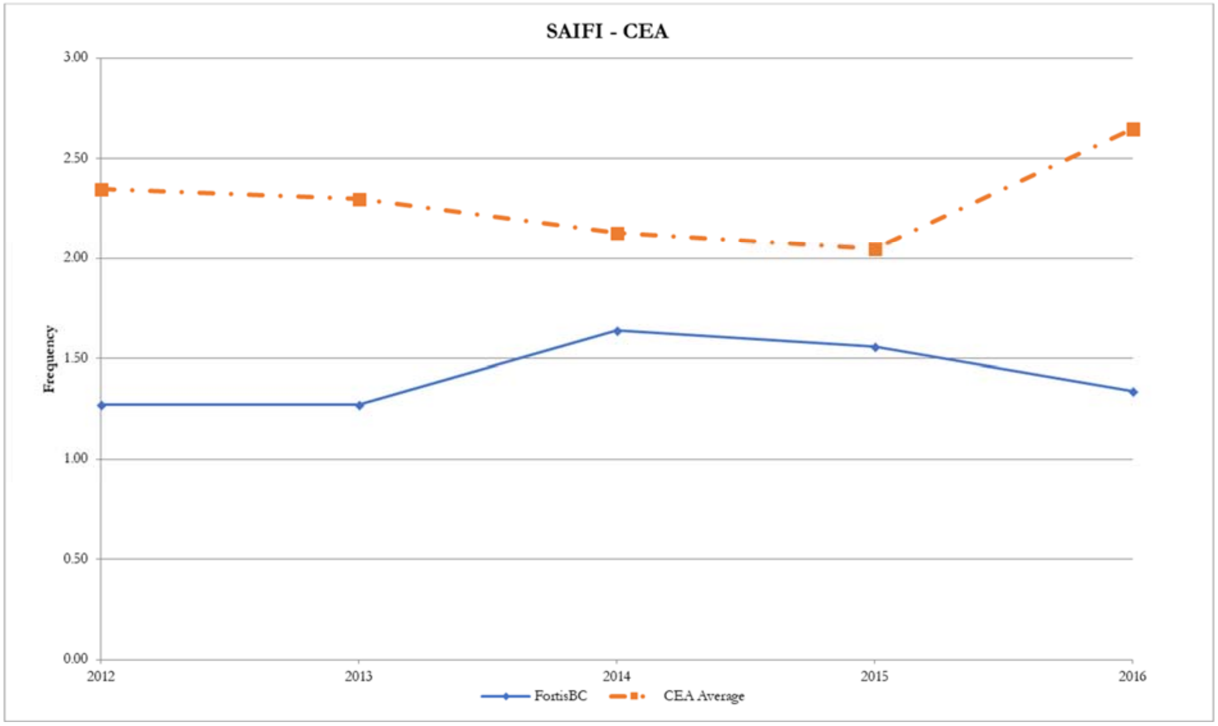


Figure 27: Canadian Electric Association Industry Average – SAIFI



For the SAIDI metric, FBC and the peer group medians were fairly well clustered between 2.00 and 2.50 for the period 2012 to 2016. In 2017, FBC exceeded that bound, having a SAIDI score of approximately 4.0. FBC attributes that increase to the implementation of an Outage Management System, which automated the Company's outage data tracking and changed the definition of outage start time, and a number of significant natural disasters (*i.e.,* floods and forest fires) in FBC's service area in 2017 that did not meet the criteria for exclusion from the SAIDI calculation.[15] The Pacific Northwest U.S. peer group exceeded both FBC and the Canadian peer group (both including and excluding FBC) based on the years of data available (*i.e.*, 2012 to 2016).

Figure 22 compares FBC to an industry-wide measure of SAIDI for the period 2012 through 2016, as reported by the Canadian Electric Association. As shown in that figure, the industry-wide measure for SAIDI was more consistently in the 3.00 to 5.00 range, well above FBC's SAIDI during the period measured.

15 FBC Annual Review for 2019 Delivery Rates.

In terms of SAIFI, FBC and the Canadian peer group median (both including and excluding FBC) mostly fell between 1.2 and 1.7 between 2012 and 2016. The Pacific Northwest U.S. peer group median was closer to 1.00 over the period, based on the available data. Similar to SAIDI, FBC's 2017 SAIFI measure was negatively impacted by the aforementioned natural disasters in 2017, and, to a lesser extent, by the implementation of the Outage Management System. Figure 24 compares FBC to the industry-wide measure of SAIFI as reported by the Canadian Electric Association. Again, the industry-wide measure exceeds FBC's SAIFI results over the period studied.

3. GFOR

Figure 28: GFOR

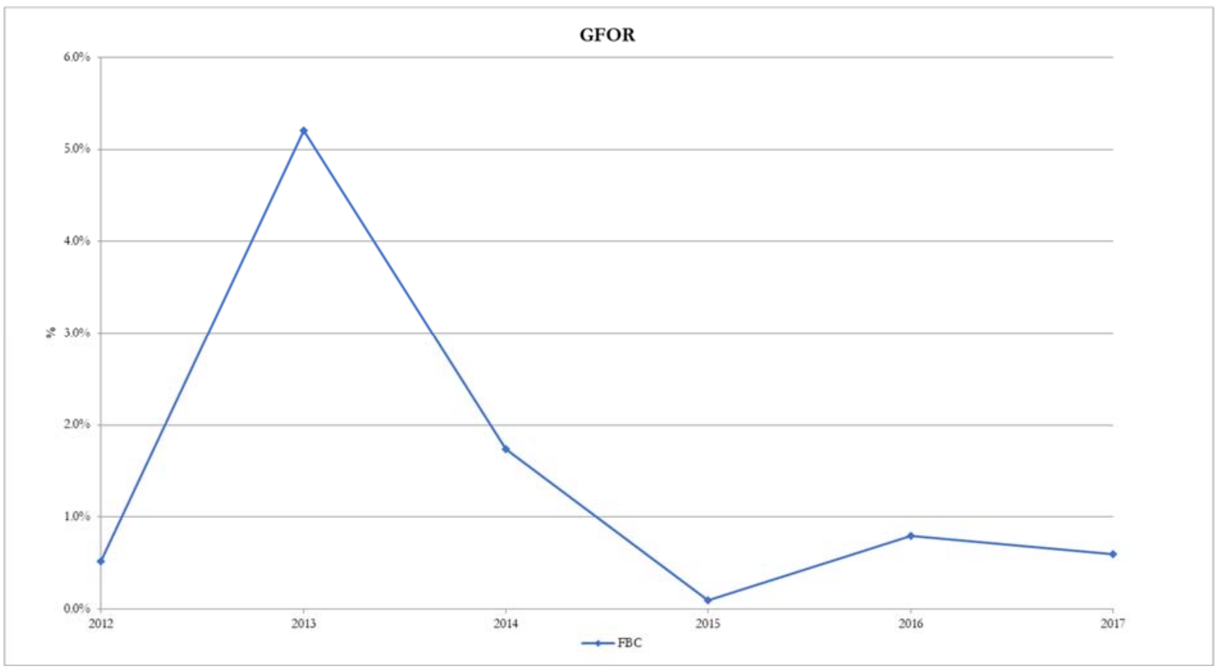
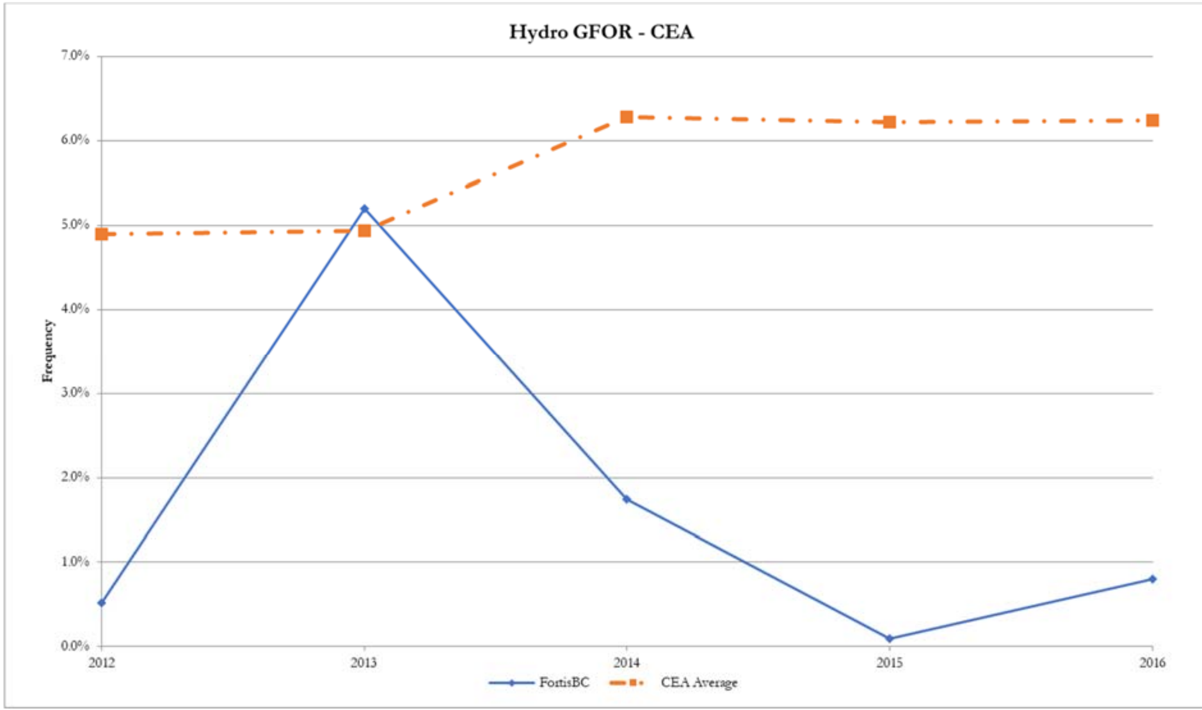


Figure 29: Canadian Electric Association Industry Average - GFOR



There was not a sufficient sample of data to benchmark FBC's GFOR against other companies. On a stand-alone basis, FBC's GFOR was below 1.00% in 2012 and 2015 through 2017. FBC's GFOR was approximately 5.0% in 2013 and closer to 2.0% in 2014. The high GFOR in 2013 was due to a fire at the Corra Linn plant that caused an extended outage.

Figure 26 compares FBC's GFOR to that of an industry measure reported by the Canadian Electric Association. FBC had a significantly better GFOR than that reported by the Canadian Electric Association in all years studied except 2013, which is discussed above.

4. Telephone Service Factor, First Contact Resolution and Abandonment Rates

Figure 30: Telephone Service Factor – Non-Emergency

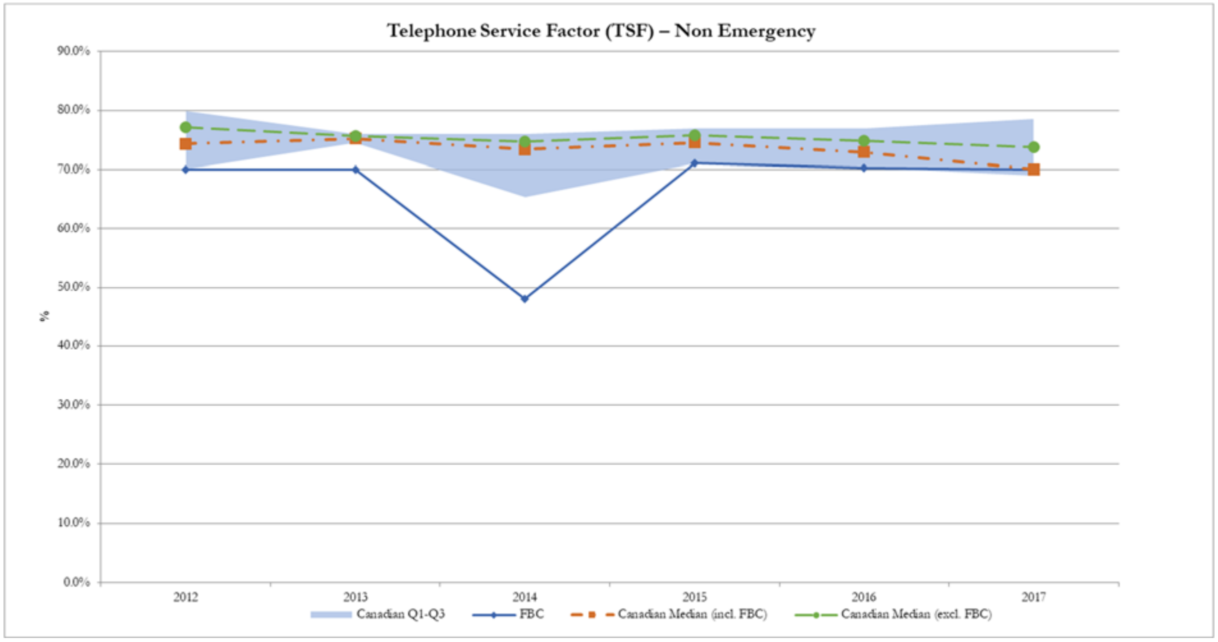


Figure 31: First Contact Resolution

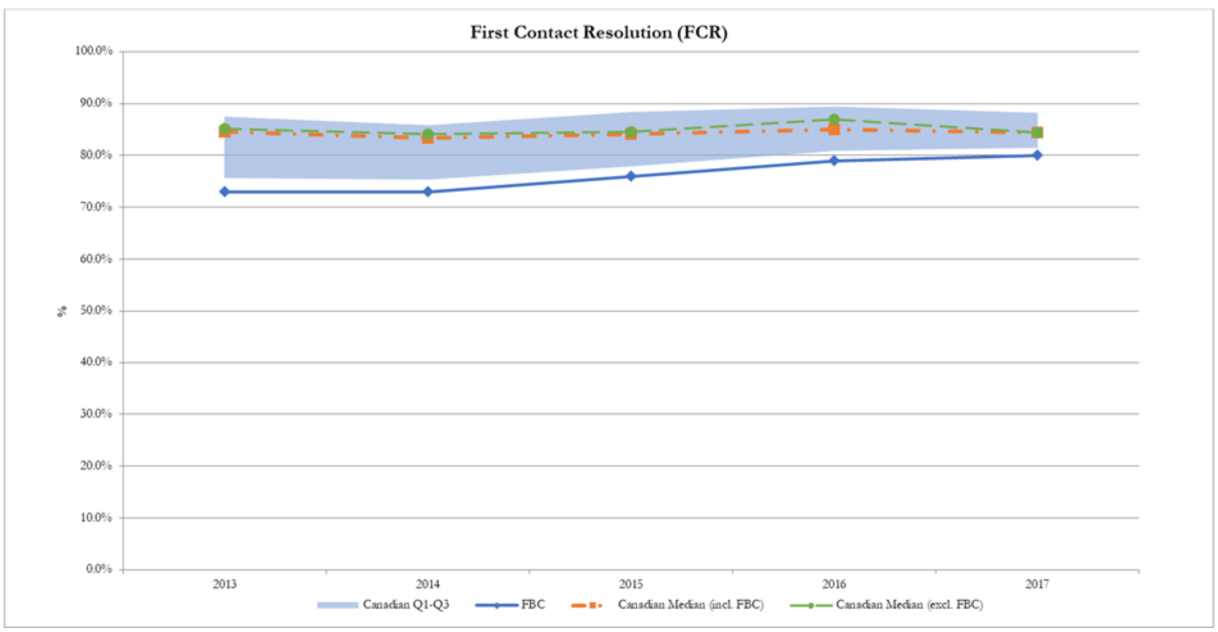
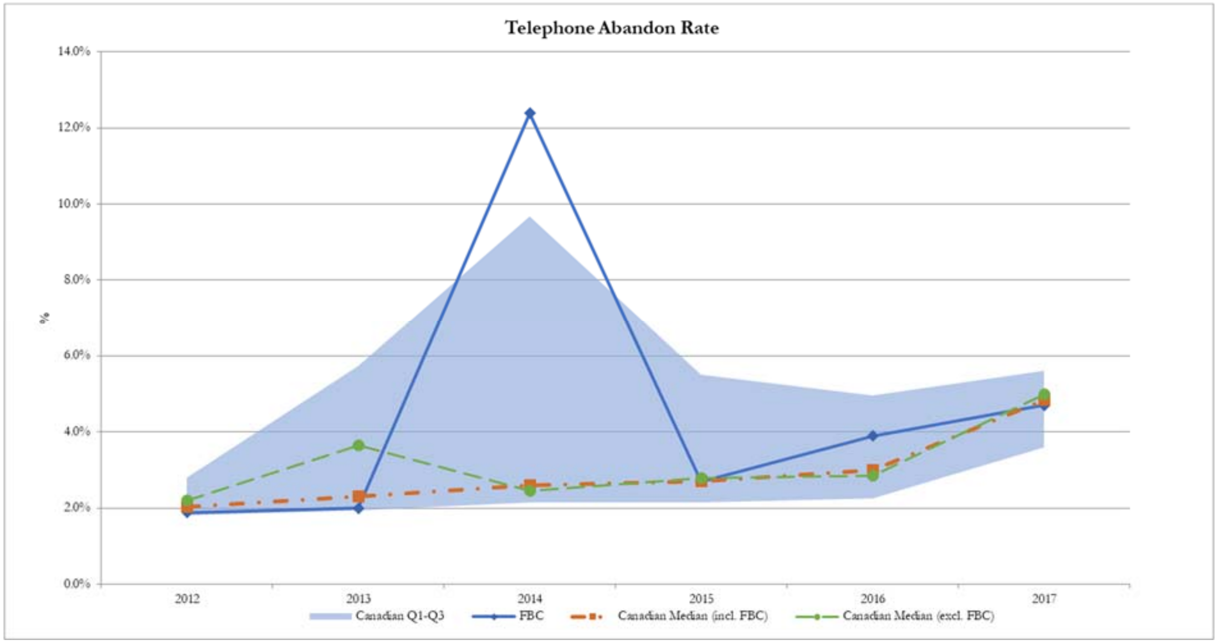


Figure 32: Telephone Abandonment Rates



The TSF (and other service quality indicators) is best viewed in the context of the utility's target benchmark TSF rate. For FBC, that rate is 70%, and the Company was at or slightly above that target over the course of the Study period, with the exception of 2014, when FBC was recovering from the impact of a labour disruption that occurred in 2013. FBC's FCR improved over the period but fell below that of the Canadian peer group median (both including and excluding FBC) in each year.[16] FBC's FCR was below its performance-based ratemaking benchmark of 78% from 2013 to 2015, but above this benchmark for the most recent two years (*i.e.*, 2016 and 2017). Finally, the Company's telephone abandonment rate was approximately that of the Canadian peer group in each year except for 2014 (*i.e.*, affected by the labour disruption in 2013).

Across these customer service metrics, FBC's performance was relatively consistent (except its weaker performance in 2014 that was driven by a labour disruption in 2013). FBC also generally lagged the Canadian peer group over this period, although not by a significant margin.

16 It is important to note that FCR can: (1) be measured differently by different companies; (2) include different customer touch points (*e.g.*, phone and Internet, or phone only); and (3) include different types of calls (*e.g.*, some peer companies, like FBC, include collections calls in the measurement of FCR, while others do not).

5. DSM Expenditures

Figure 33: DSM Expenditures (with incentives)/Customer

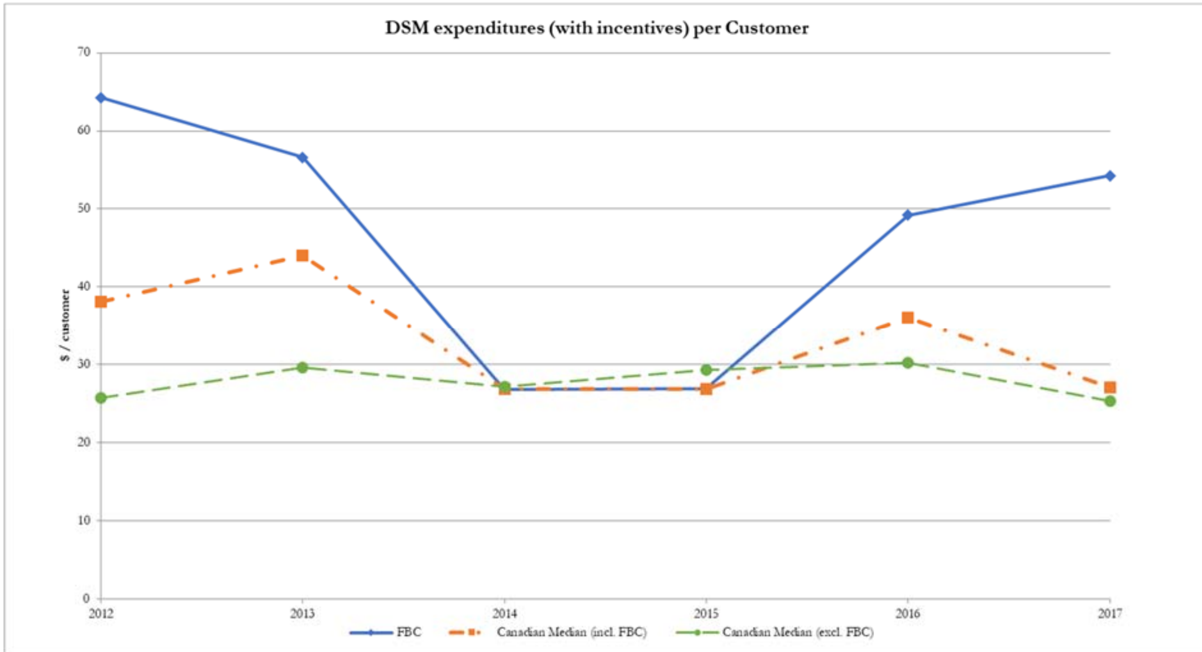


Figure 34: DSM Expenditures (without incentives)/Customer

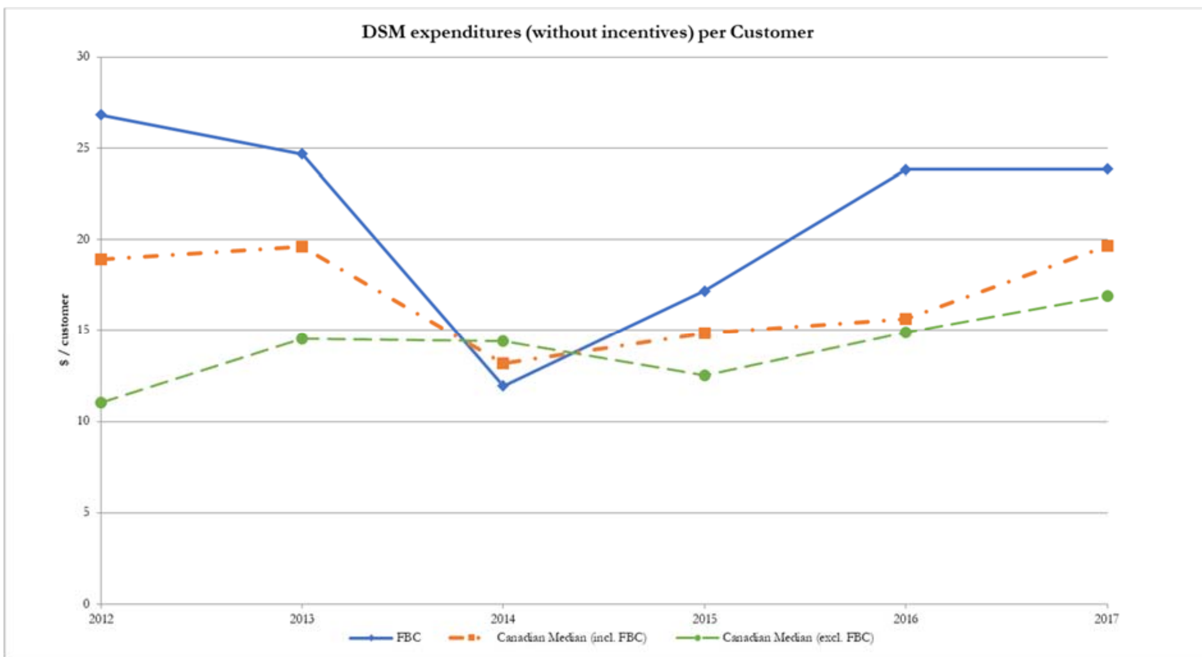
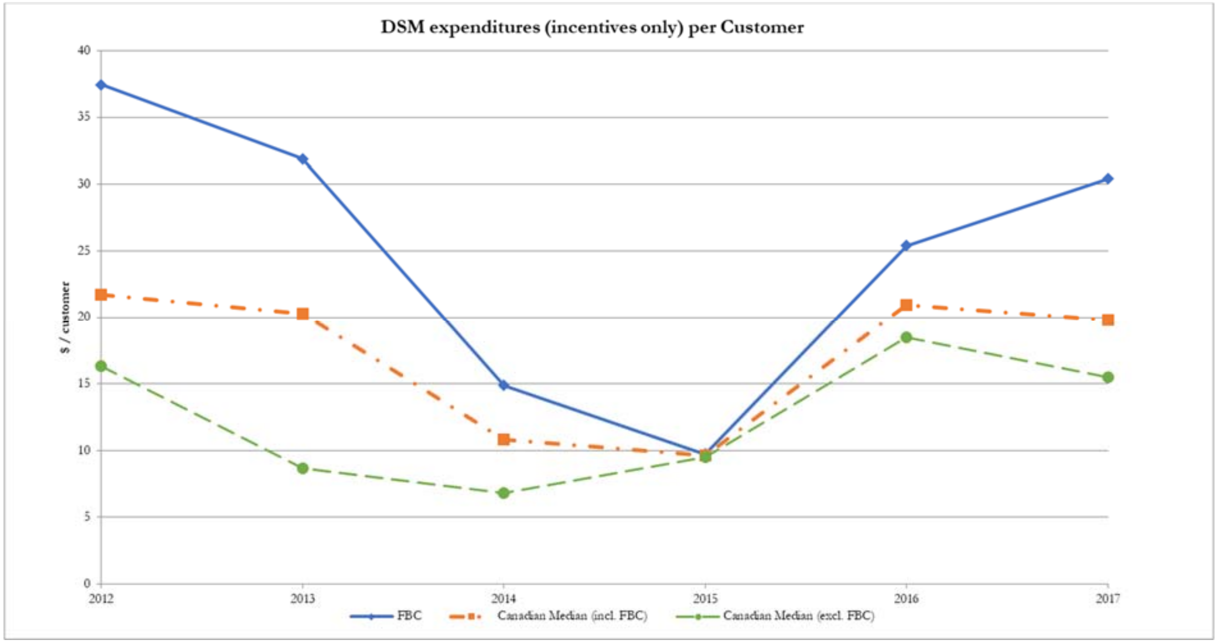


Figure 35: DSM Expenditures (incentives only)/Customer



FBC's DSM expenditures per customer (both with and without incentives) were higher than or at the median of the Canadian peer group (both including and excluding FBC) in every year of the Study except for 2014, when the Company's DSM spending without incentives was just below that of the peer group median (both including and excluding FBC).[17] The level of DSM expenditures is dependent on the availability of regulatory mechanisms for cost recovery and the utility's efficiency in deploying these programs.

VI. SUMMARY AND CONCLUSIONS

The Study focused on a series of metrics designed to examine the relative efficiency of the Company in terms of its O&M expense profile, capital investment, reliability, customer service, and other factors. Benchmarking is a commonly employed analytical technique used across a wide variety of industries to compare a company's performance against an industry group, which serves as the benchmark. The benefits of benchmarking are its intuitive appeal and the ability to compare against companies chosen from within the same industry. Limitations of benchmarking include the fact that detailed data across companies beyond top line revenue and cost categories can be difficult to glean from public sources.

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[17] Non-incentive expenditures include indirect costs associated with DSM programs (*e.g.*, program administration, communication and outreach, research and evaluation of the program, *etc.*).

Further, the benchmarking comparison is a relative one, and therefore does not offer insights into optimal performance in an absolute sense.

The industry peer groups used in the Study were selected according to criteria designed to produce peer groups with operating circumstances similar to FBC. Criteria used to select companies included their types of operations, their geographical location, and whether or not they were rate regulated. The peer group was also limited based on the companies for which data was publicly available and/or those companies that agreed to provide data in response to Concentric's survey. Concentric was able to develop Canadian and Pacific Northwest U.S. peer groups that were sufficiently large and that provided a reasonable basis on which to benchmark the Company's performance.

The Study focused on benchmarking metrics that measure financial efficiency, reliability, and customer service performance. These metrics were chosen in consultation between the Company and stakeholders. In Concentric's opinion, the metrics used in the Study provide a reasonably comprehensive overview of FBC's relative performance from both a financial and a non-financial basis.

Results Summary

The following figure summarizes the benchmarking analyses presented in the Study. Specifically, the figure presents the percentage difference between FBC's result and the Canadian peer group's median (including FBC) result, per metric, per year. For those metrics and years where FBC performed better than the median, the result is shaded green in the figure. Where FBC was at the median or there was an insufficient sample of peer group companies, no shading is used. For those metrics and years where FBC performed worse than the median, the result is shaded red in the figure.

Figure 36: Summary of Benchmarking Analyses

% Difference - FBC from Canadian Median	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	-4%	-11%	-5%	-6%	-4%	-4%
Distribution O&M + Total A&G per MWh	-5%	-21%	-15%	-11%	-10%	-13%
Distribution O&M + Total A&G per Employee	-52%	-41%	-39%	-45%	-40%	-48%
Distribution O&M + Total A&G per km Distribution Line	-44%	-46%	-23%	-25%	-16%	-9%
Distribution Net Plant per Customer	127%	122%	117%	117%	106%	98%
Distribution Net Plant per Employee	10%	43%	22%	12%	11%	0%
Distribution Net Plant per km Distribution Line	42%	47%	50%	52%	47%	73%
Administrative and General Expense per Customer	-4%	-11%	-2%	-3%	0%	1%
Administrative and General Expense per MWh	-4%	-10%	0%	-14%	-3%	-2%
Customer Care Expense per Customer	44%	62%	63%	42%	19%	30%
Customer Care Expense per MWh	29%	49%	55%	51%	17%	17%
Interest Expense per Customer	138%	123%	122%	108%	87%	85%
Emergency Response Time (within 2 hrs)	3%	5%	17%	5%	5%	3%
SAIDI	-1%	0%	0%	0%	-4%	80%
SAIFI	-2%	0%	0%	2%	-7%	11%
Generator Forced Outage Rate	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non Emergency	-6%	-7%	-35%	-5%	-4%	0%
First Contact Resolution	NA	-14%	-12%	-10%	-7%	-5%
Telephone Abandon Rate	-8%	-13%	376%	0%	30%	-3%
DSM Expenditures (with incentives) per Customer	69%	29%	0%	0%	36%	101%
DSM Expenditures (without incentives) per Customer	42%	26%	-9%	16%	52%	21%
DSM Expenditures (incentives only) per Customer	73%	57%	37%	1%	21%	54%

In terms of the financial metrics, FBC outperformed or met the peer group median in six out of the twelve metrics analyzed in most years studied, and lagged the peer group medians in six areas.

FBC performed better than the median at the broadest expense level analyzed (*i.e.*, distribution O&M plus total A&G) on a per customer, per volume, per employee, and per kilometre of distribution line basis, as well at the A&G expense level on both a per-customer and per-volume basis. FBC performed less favorably, on a relative basis, on a net plant per customer, employee, and kilometre of distribution line basis, interest expense per customer basis, and customer care metrics.

In terms of reliability, customer service, and other metrics, FBC performed at or better than the peer group median on three of the metrics in all years (emergency response time, total DSM per customer, and DSM incentives only per customer); at or better than the median on three metrics for most years (SAIDI, SAIFI, and DSM expenditures excluding incentives per customer); and at or below the median on two metrics for most years (TSF-non-emergency and FCR).

In terms of reliability, FBC's SAIDI and SAIFI were better than or close to the median for all years, except for 2017. As mentioned earlier in the Study, the increase in 2017 coincided with the implementation of a new Outage Management System, which automated the Company's outage data tracking and changed the definition of outage start time, as well as a number of significant natural disasters (*i.e.,* floods and forest fires) in FBC's service area in 2017 that did not meet the criteria for exclusion from the SAIDI and SAIFI calculations. There was insufficient peer group data to benchmark FBC's GFOR against other companies. However, FBC's performance was better than the industry average for SAIDI, SAIFI, and GFOR based on the industry-wide measures of those metrics as reported by the Canadian Electric Association. In terms of emergency response time, FBC performed above the Canadian peer group median in each year of the study period. FBC's emergency response time was at or above its performance-based ratemaking benchmark of 93% for the years 2013, 2016 and 2017.

FBC performed at or below the peer group median on two of the metrics (*i.e.*, TSF – non-emergency and FCR) in all years. However, FBC's TSF-non-emergency results were above the Company's performance-based ratemaking benchmark of 70% benchmark for all years except for 2014, which was impacted by a labour disruption, as discussed earlier. FBC's FCR was below its performance-based ratemaking benchmark of 78% from 2013 to 2015, but above this benchmark for the most recent two years (*i.e.*, 2016 and 2017). Across these customer service metrics, FBC's performance was relatively consistent (except its weaker performance in 2014 that was driven by a labour dispute disruption in 2013). FBC also generally lagged the Canadian peer group over this period, although not by a significant margin.

In terms of DSM expenditures, FBC's total DSM expenditures per customer (both with and without incentives) were higher or at the median of the Canadian peer group in every year of the Study except for 2014, when the Company's DSM spending without incentives was just below that of the peer group. As discussed herein, however, the level of DSM expenditures is dependent on the availability of regulatory mechanisms for cost recovery and the utility's efficiency in deploying these programs.

In summary, Concentric examined FBC's performance on a stand-alone basis, and also analyzed FBC's performance relative to 14 utilities in Canada and the U.S. across six years and 22 metrics. In terms of analyzing FBC's performance on an isolated basis, the Company's OM&A and net plant increased modestly over the period studied on a nominal basis (five-year CAGRs of 2.08% and 2.95%, respectively), and increased by less than 1.00% year-over-year on a real basis (based on a five-year average annual increase in the Consumer Price Index of 1.39%). On a relative basis, the Company performed at or better than the peer group median in the majority of the expense-related metrics analyzed, but performed less favorably on the metrics related to net plant per customer, employee, and kilometre of distribution line, interest expense per customer, and customer care expenses per customer and per MWh. In terms of service quality and reliability metrics, the results were more varied, but also require more context, whether it be understanding the target metrics to which the Company is performing (*e.g.*, for TSF and FCR), or the drivers behind the performance trends (*e.g.*, for DSM spending). Where possible in the Study, Concentric captured that context in order to provide perspective regarding the Company's benchmarked results.

Appendix A: Data Survey Template – Electric Companies

	Metric	Description of Metric	2012	2013	2014	2015	2016	2017	Comment
	Determinants								
1	# of Customers	# of Total Customers							
2	# of FTE Employee	# of FTE Employees (serving Electric Operations only for companies with both Electric and Gas Operations)							
3	Volume Sold	Total Energy Delivered (Please specify Unit in the "Comments" column)							
	Plant and Capital Expenditures								
	Net Plant								
4	Intangible Plant								
5	Production Plant								
6	Transmission Plant								
7	Distribution Plant								
8	General Plant								
9	Other Plant	Please specify what is included in the "Other" category in the "Comment" Column.							
10	Total Net Plant								
11	Rate Base	Total Rate Base							
	Expenses								
	Operating, Maintenance and Administration (OM&A)	This includes all O&M costs net of capitalized overheads							
12	Production Expense (excluding Fuel and Purchased Power)								
13	Transmission Expense								
14	Distribution Expense								
15	Administrative and General Expense								
16	Customer Care Expense	This includes Customer Accounts and Customer Service Expenses							
17	Other O&M Expense	Please specify what is included in the "Other" category in the "Comment" Column							
18	Total O&M Expense (excluding Fuel and Purchased Power)								
19	Total Interest Expense	This measures the total Interest Expense							
	Safety, Reliability of the system and Quality of the service								
20	Emergency Response Time (within 2 hours)	Percent of emergency calls responded to within two hours							
21	System Average Interruption Duration Index (SAIDI) – Normalized	Total customer hours of interruption divided by the total number of customer served, after adjusting for the impact of Major Events (as adjusted using the Institute of Electrical and Electronics Engineer method of normalizing reliability statistics for Major Events)							
22	System Average Interruption Frequency Index (SAIFI) - Normalized	Total number of customer interruptions divided by the total number of customer served, after adjusting for the impact of Major Events (as adjusted using the Institute of Electrical and Electronics Engineer method of normalizing reliability statistics for Major Events)							
23	Generator Forced Outage Rate (GFOR)	Percentage of time in one year that the generating units experienced forced outage rates compared to the amount of time they could have operated without a forced outage							
	Customer Care Service Levels								
24	Telephone Service Factor (TSF) – Non Emergency	Number of calls answered within 30 seconds divided by number of calls received							
25	First Contact Resolution (FCR)	% of customers who achieved call resolution in 1 call							
26	Telephone Abandon Rate	Total # of Abandoned Calls divided by total number of answered calls plus abandon calls							
	Other								
27	Demand Side Management (DSM) expenditures with incentives	This includes DSM expenditures with incentives							
28	Demand Side Management (DSM) expenditures without incentives	This includes DSM expenditures without incentives							
29	GHG Emissions								

Appendix B – Canadian Utility Data Gathering Process

Data Gathering

Concentric began the data gathering process by reviewing public sources to assess the availability of data for the potential proxy companies. Concentric's research indicated that, for Canadian utilities, publicly-available data would be insufficient for the Study. That conclusion was based on the following factors:

- Data was not widely enough reported and available to calculate and analyze the specific benchmarking metrics chosen for the Study. For example, Canadian utilities do not universally and consistently report/present their financial data by functional category (*i.e.*, distribution, transmission, generation, *etc.*). Similarly, operations, maintenance, and administrative (OM&A) expenses tend to be reported at one aggregated level and in some instances include the cost of fuel and purchased power.
- The data was not consistently available for all years. For example, for certain companies, Concentric found some relevant data for certain years through rate case documents. However, since rate cases are not consistently filed on an annual basis, data obtained from rate case documents was insufficient for purposes of benchmarking.
- For certain companies, the reporting format for the data that was publicly available was not reported consistently from year to year. For example, certain reported categories would change from one year to the other. Additionally, some companies changed their reporting period from calendar year to fiscal year during the period of the study.

Based on Concentric's finding that publicly-available data would be insufficient for the purposes of benchmarking FBC against other Canadian utilities, Concentric developed a data survey for use in the direct request of data from Canadian utilities. Specifically, Concentric initiated a formal outreach process requesting the specific data elements provided in Appendix A to the Study. Concentric requested that participants provide their data via a Microsoft Excel template that Concentric created. The goal of the template was to ensure that the data provided would be in a consistent format. In addition, the use of such a template reduces errors and limits the need to go back to the survey respondents to ensure that data is being provided on a comparable basis.

Of the companies contacted, Concentric received data from 60% of electric utilities. Some survey respondents requested that their data be maintained on a confidential basis in return for providing the data for Concentric's analysis. Concentric agreed to that condition in consultation with FBC, as confidential treatment of the data was critical to Concentric receiving such a high participation rate from the surveyed companies. Concentric offered to take the following specific steps to preserve the confidentiality of the data provided:

- Mask the name of the companies while presenting the results.
- Disclose the name of the companies that are part of our analysis in one list within the report.
- Present only normalized data (*e.g.*, $/customer or $/volume).
- The raw data provided by each company to Concentric would not be shared with anyone, including FBC personnel, other than Concentric personnel working on the Study.

<u>Data Retrieval and Validation</u>

Concentric took steps to ensure that the data provided by the companies was accurate and was reported in the format requested. Even with the use of a standard template, Concentric still performed several iterations of data review with the survey participants to understand, validate and normalize the data.

After receiving the data, Concentric critically reviewed the data to identify potential discrepancies and anomalies. When Concentric identified potential discrepancies or anomalies, Concentric followed-up with the relevant companies to understand the data and/or obtain supplemental information. On a test basis, Concentric also independently checked survey data against the limited publicly-available data that Concentric collected to verify the survey data's correctness.

Other instances that required follow-up with the survey respondents included:

(1) Some companies did not initially categorize expenses by the functional categories requested, so Concentric worked with those companies to provide the data in the format requested. Concentric provided the detailed descriptions of what types of costs belong in each category to help categorize the data correctly. Concentric relied on the U.S. Federal Energy Regulatory Commission's Uniform System of Accounts extensively for this purpose.

(2) Concentric also ensured that the financial data provided matched the volume and customer data provided in terms of ensuring that the data provided covered the same services and customer types. Specifically, Concentric verified with the companies that the number of

customers and volumes reported matched the financial data associated with serving those customers and volumes.

Based on that process, Concentric was able to include a significantly greater number of Canadian utilities in the Study while ensuring that the data was incorporated in the analyses on a consistent basis.

FortisBC Energy Inc. and FortisBC Inc. Benchmarking Study

CONCENTRIC ADVISORS

2018

Overview

1. Approach to Benchmarking
2. Highlights of FEI Benchmarking Study – Concentric, with General Discussion by All
   a. Review results and findings
   b. General discussion
3. Highlights of FBC Benchmarking Study – Concentric, with General Discussion by All
   a. Review results and findings
   b. General discussion
4. Summary and Wrap-up

Approach to Benchmarking

- Background on benchmarking
- Determination of industry peer groups
- Benchmarking metrics and data sources
- Benchmarking methodology

Background on Benchmarking

- Commonly employed analytical technique used across a variety of industries
- Provides:
  - Comparison of subject company to peers
  - Determination of average and best of class performance, as well as results by quartile
  - Identification of trends
- Does not provide:
  - Quantification of causal relationships
  - Insights into optimal performance in an absolute sense
- The benefits of benchmarking are its intuitive appeal and the ability to compare the subject company to industry peers

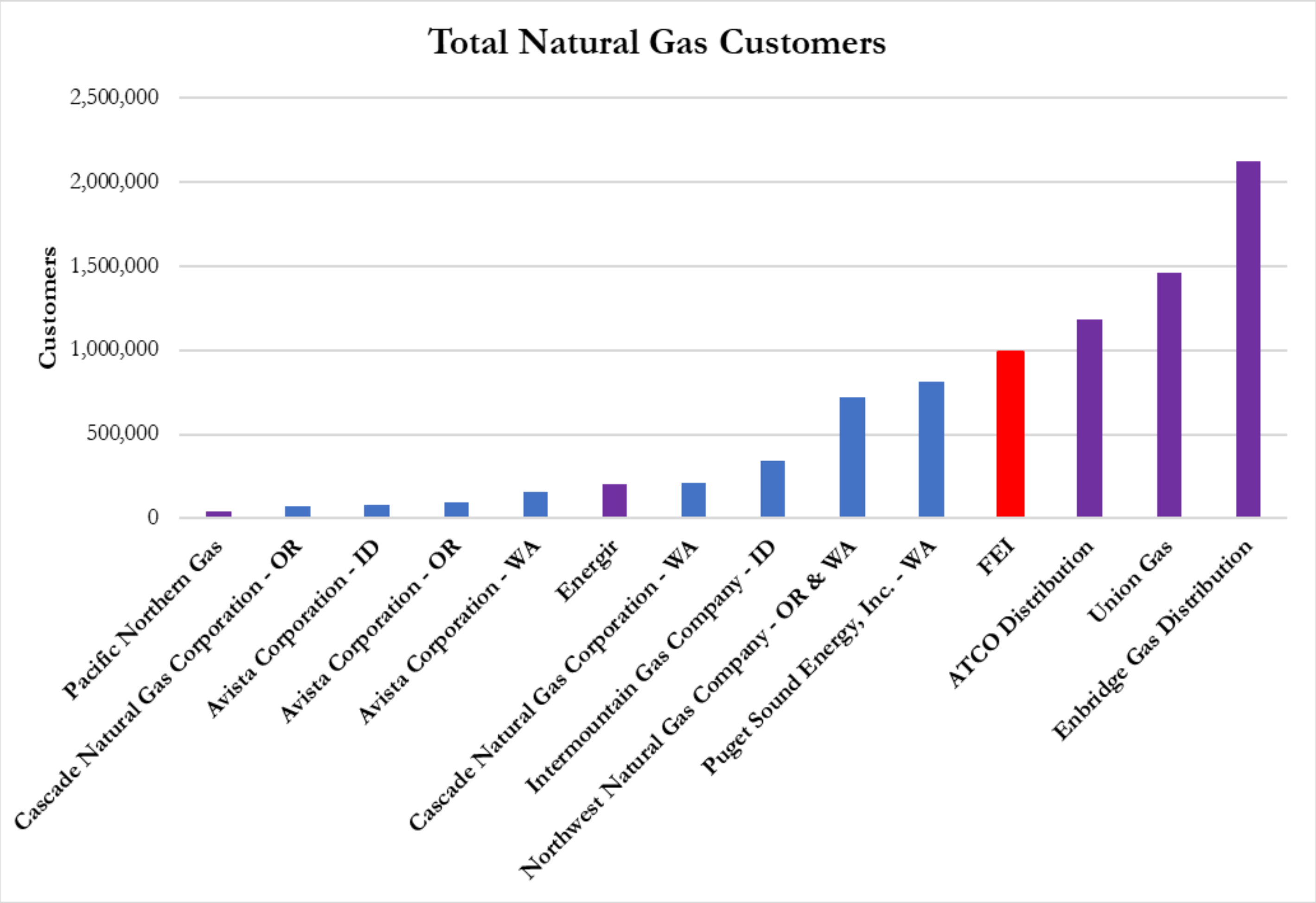
Determination of industry peer groups

- Comparable Canadian electric and natural gas distribution utilities, and comparable utilities in the Pacific Northwest U.S.
- Rate regulated companies
- Peer group data considerations (Canadian Utilities)
  - Concentric received data from five of eight natural gas companies surveyed, and nine of 15 electric companies
    - Data provided on a confidential basis

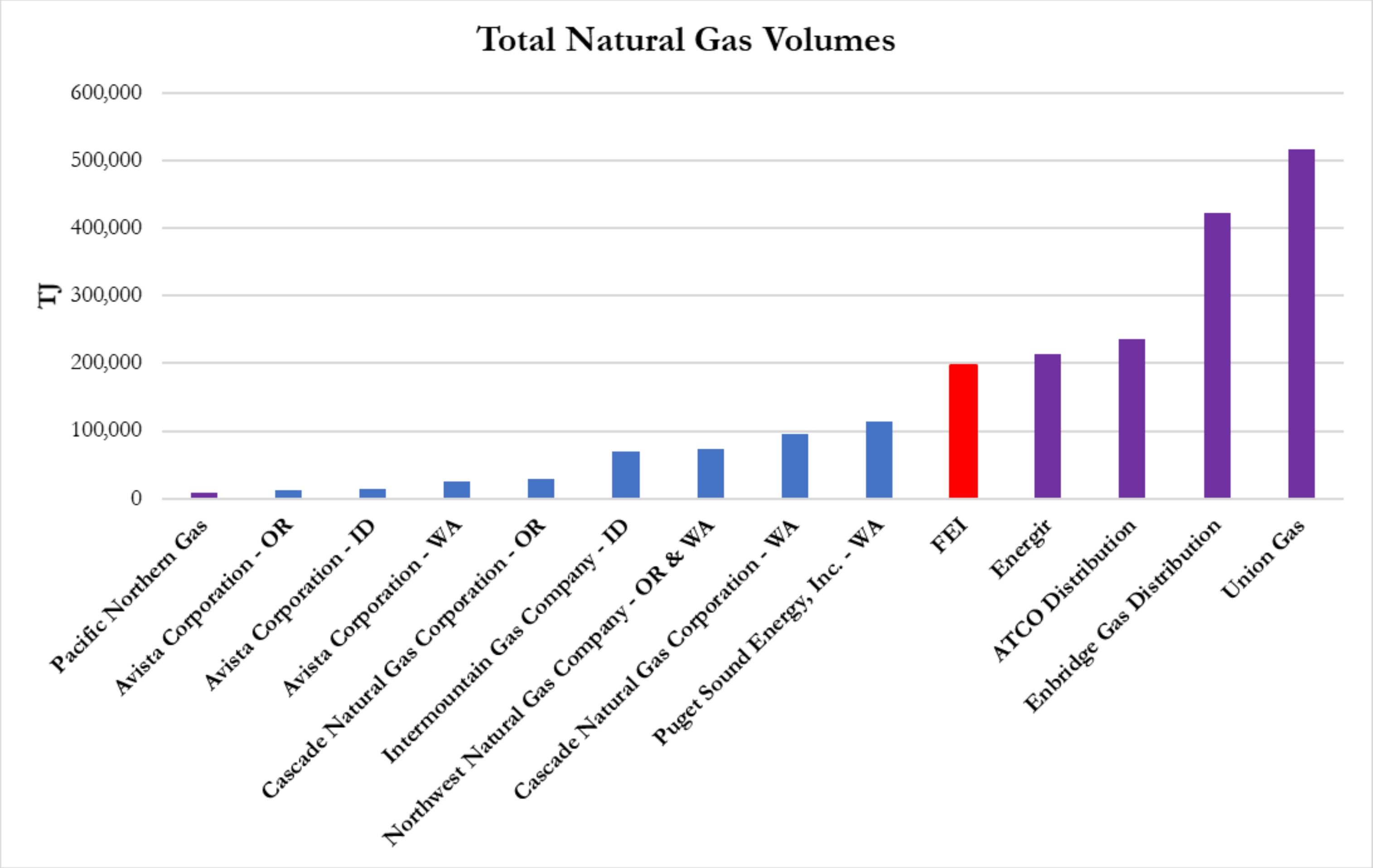
Peer Group – FEI Benchmarking Study

No.	Company Name	Ultimate Parent Company Name	State(s)/ Province of Operation
Canadian Natural Gas Utilities			
1	ATCO Gas Distribution	ATCO Ltd.	Alberta
2	Enbridge Gas Distribution	Enbridge Inc.	Ontario
3	Energir	Energir Inc.	Quebec
4	Pacific Northern Gas	AltaGas Ltd.	British Columbia
5	Union Gas	Enbridge Inc.	Ontario
Pacific Northwest U.S. Natural Gas Utilities			
1	Avista Corporation – Idaho	Avista Corp.	Idaho
2	Avista Corporation – Oregon	Avista Corp.	Oregon
3	Avista Corporation – Washington	Avista Corp.	Washington
4	Cascade Natural Gas Corporation – Oregon	MDU Resources Group, Inc.	Oregon
5	Cascade Natural Gas Corporation – Washington	MDU Resources Group, Inc.	Washington
6	Intermountain Gas Company – Idaho	MDU Resources Group, Inc.	Idaho
7	Northwest Natural Gas Company – Oregon and Washington	NW Natural	Oregon, Washington
8	Puget Sound Energy – Washington	Puget Sound Energy	Washington

Peer Group – FEI Benchmarking Study (cont.)



Peer Group – FEI Benchmarking Study (cont.)



FEI Peer Group – Functional Mix

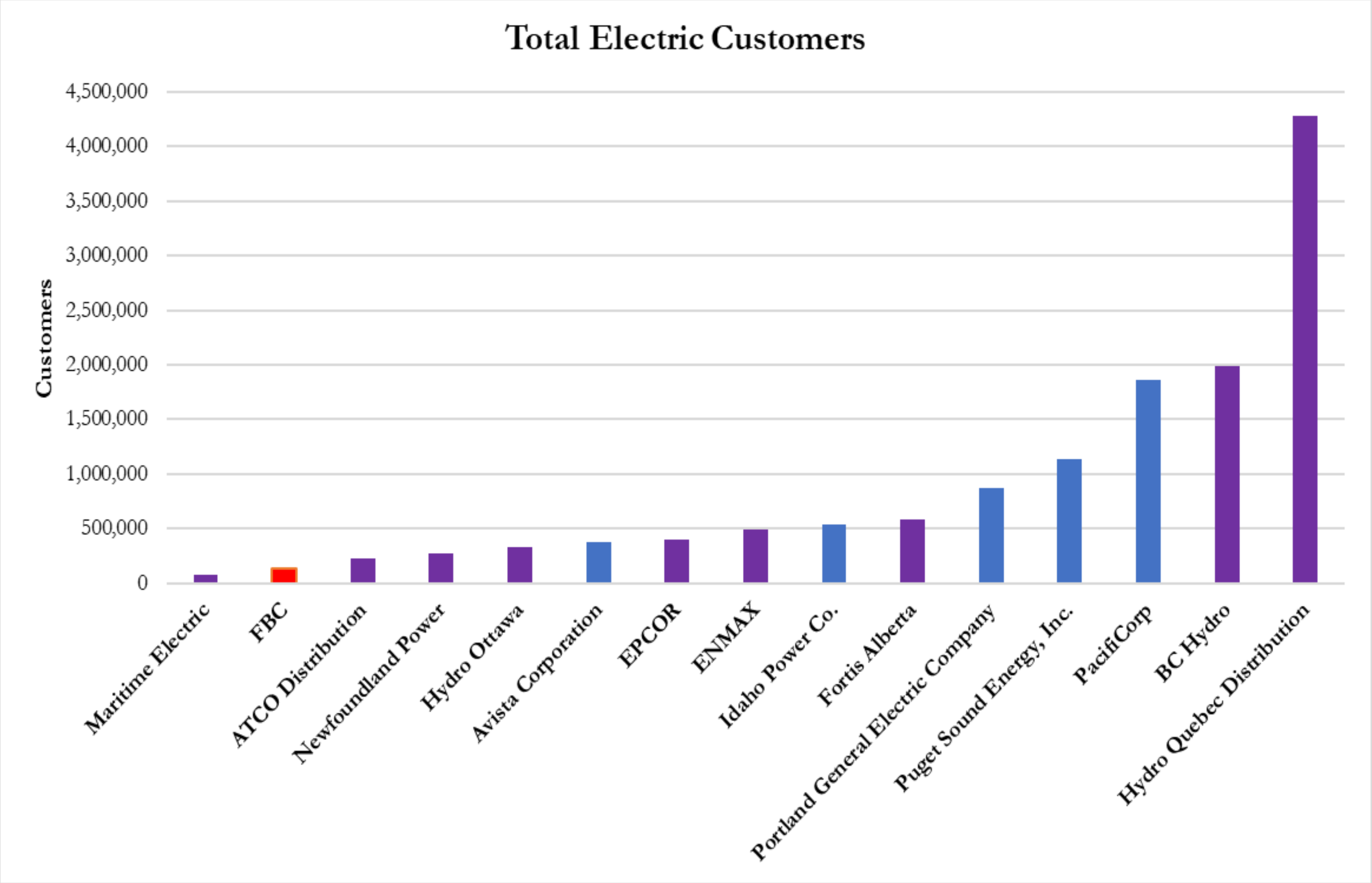
Company	Distribution	Transmission	Storage	Other
FEI	**58%**	**28%**	**5%**	**9%**
Company A[1]	N/A	N/A	N/A	N/A
Company B[1]	N/A	N/A	N/A	N/A
Company C	43%	51%	0%	6%
Company D	45%	33%	13%	9%
Company E	63%	6%	8%	23%
Company F	65%	13%	5%	17%
Company G	84%	0%	0%	16%
Company H	87%	0%	0%	13%
Company I	89%	0%	0%	11%
Company J	92%	0%	4%	4%
Company K	94%	1%	1%	4%
Company L	97%	0%	2%	2%
Company M	97%	0%	0%	3%
Average	**76%**	**11%**	**3%**	**10%**

[1] Net plant was not reported at the functional level for these companies.

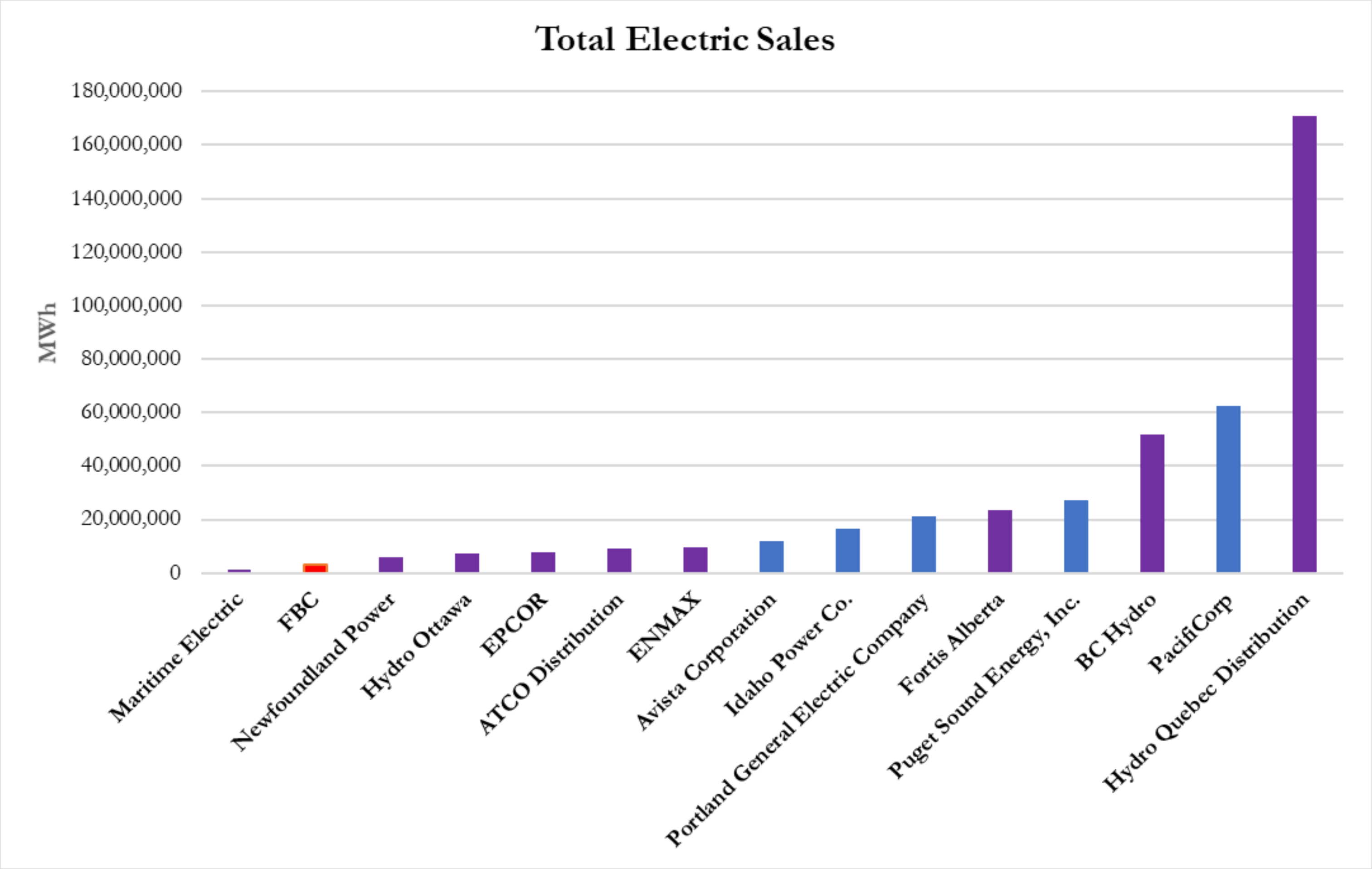
Peer Group – FBC Benchmarking Study

No.	Company Name	Ultimate Parent Company Name	State(s)/ Province of Operation
Canadian Electric Utilities			
1	ATCO Electric Distribution	ATCO Ltd.	Alberta
2	Maritime Electric	Fortis Inc.	Prince Edward Island
3	Fortis Alberta	Fortis Inc.	Alberta
4	Newfoundland Power	Fortis Inc.	Newfoundland
5	ENMAX	ENMAX Corporation	Alberta
6	EPCOR	EPCOR Utilities Inc.	Alberta
7	Hydro Quebec Distribution	Hydro Quebec	Quebec
8	Hydro Ottawa	Hydro Ottawa Holding Inc.	Ottawa
9	BC Hydro	BC Hydro	British Columbia
Pacific Northwest U.S. Electric Utilities			
1	Avista Corporation	Avista Corp.	Idaho, Montana, Washington
2	Idaho Power Co.	Idaho Power Co.	Idaho, Oregon
3	PacifiCorp	PacifiCorp	California, Idaho, Oregon, Utah, Washington, Wyoming
4	Portland General Electric Company	Portland General Electric Company	Oregon
5	Puget Sound Energy, Inc.	Puget Sound Energy, Inc.	Washington

Peer Group – FBC Benchmarking Study (cont.)



Peer Group – FBC Benchmarking Study (cont.)



FBC Peer Group – Functional Mix

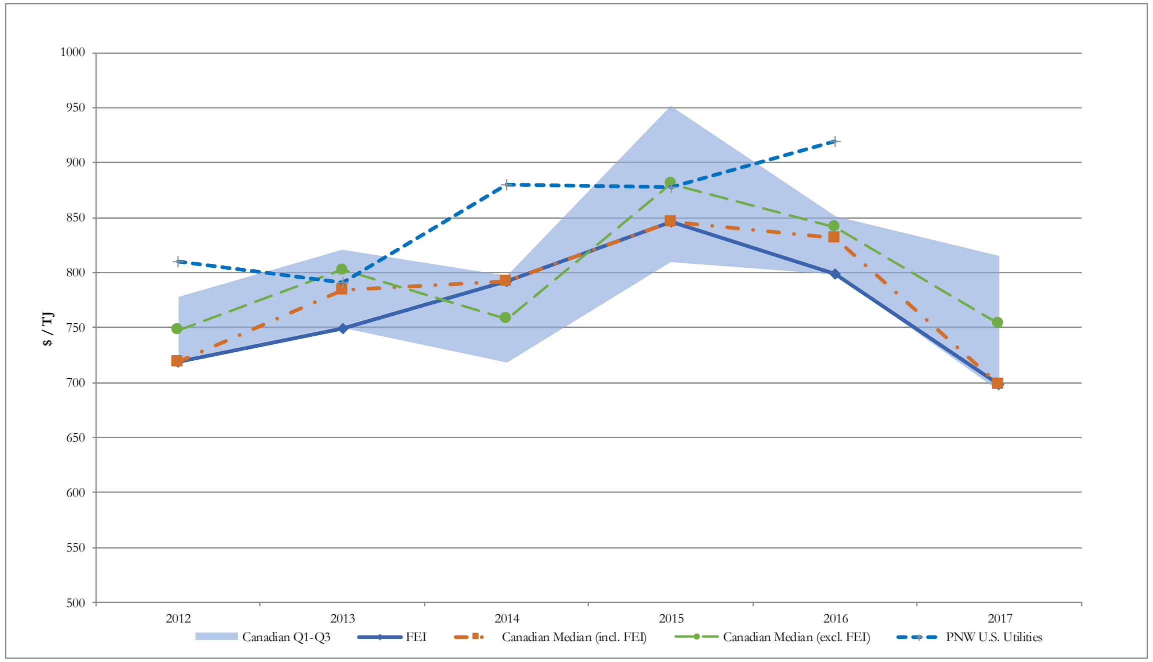
Company	Distribution	Transmission	Generation	Other
FBC	**54%**	**25%**	**13%**	**8%**
Company A	22%	25%	43%	9%
Company B	26%	6%	52%	16%
Company C	26%	34%	33%	7%
Company D	30%	22%	40%	9%
Company E	40%	17%	38%	5%
Company F	43%	20%	32%	6%
Company G	54%	23%	13%	10%
Company H	58%	36%	0%	6%
Company I	61%	19%	14%	7%
Company J	74%	26%	0%	0%
Company K	82%	0%	0%	18%
Company L	88%	0%	0%	12%
Company M	99%	0%	0%	1%
Company N	100%	0%	0%	0%
Average	**57%**	**17%**	**19%**	**8%**

Metrics and Data Sources

- Metrics:
  - Financial and non-financial metrics that measure the utilities' relative financial efficiency, reliability, and customer service performance
  - Chosen in consultation between FortisBC and stakeholders
- Data sources
  - Publicly-available sources
  - Survey data
  - Data validation process
  - Confidentiality

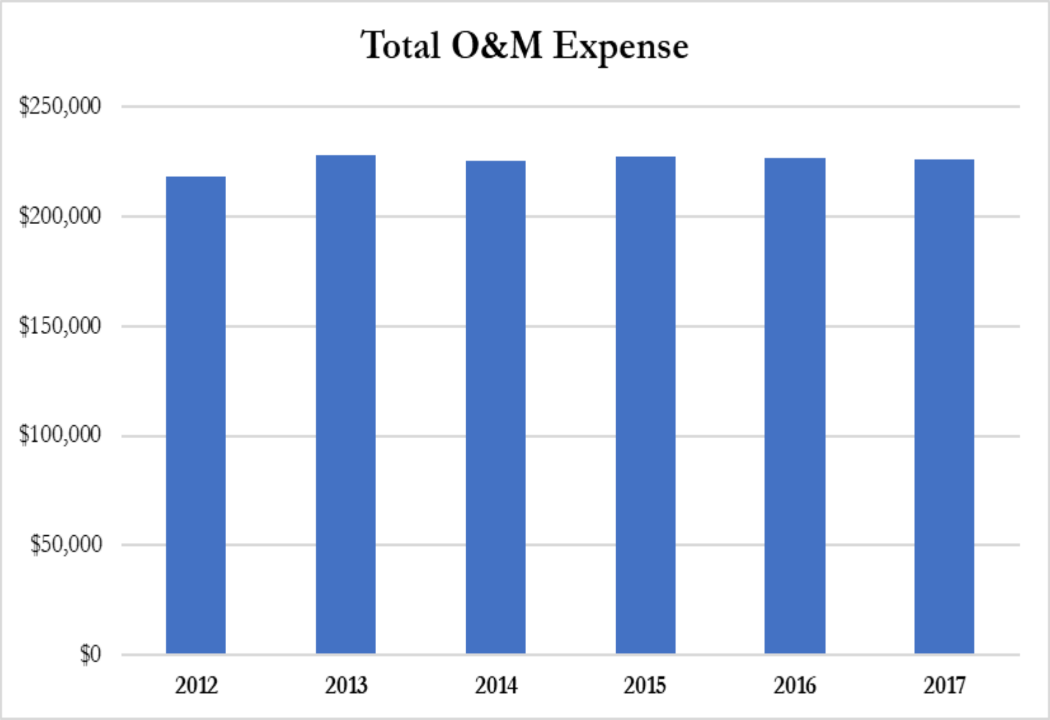
Benchmarking Methodology

- Evaluated FEI and FBC on stand-alone and comparative bases, over time
- Comparative analyses focused on four proxy group data points:
  - Canadian proxy group (*including* FEI/FBC) median
  - Canadian proxy group (*excluding* FEI/FBC) median
  - Pacific Northwest U.S. median
  - Canadian "Q1-Q3" range

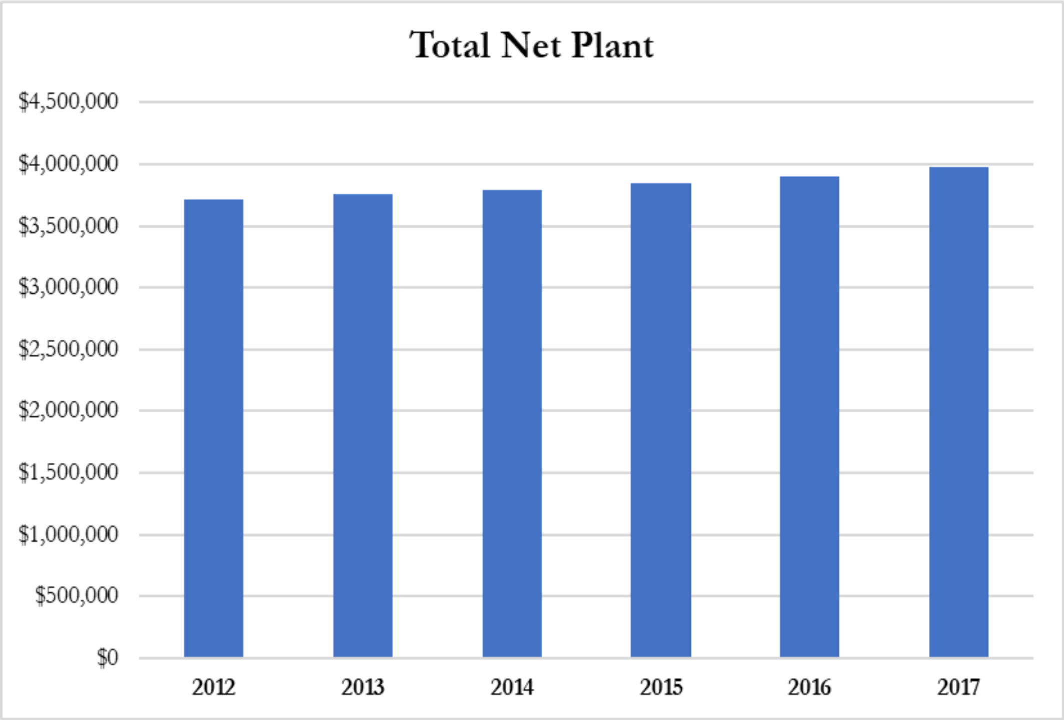


Highlights of FEI Benchmarking Study

Highlights of FEI Benchmarking Study

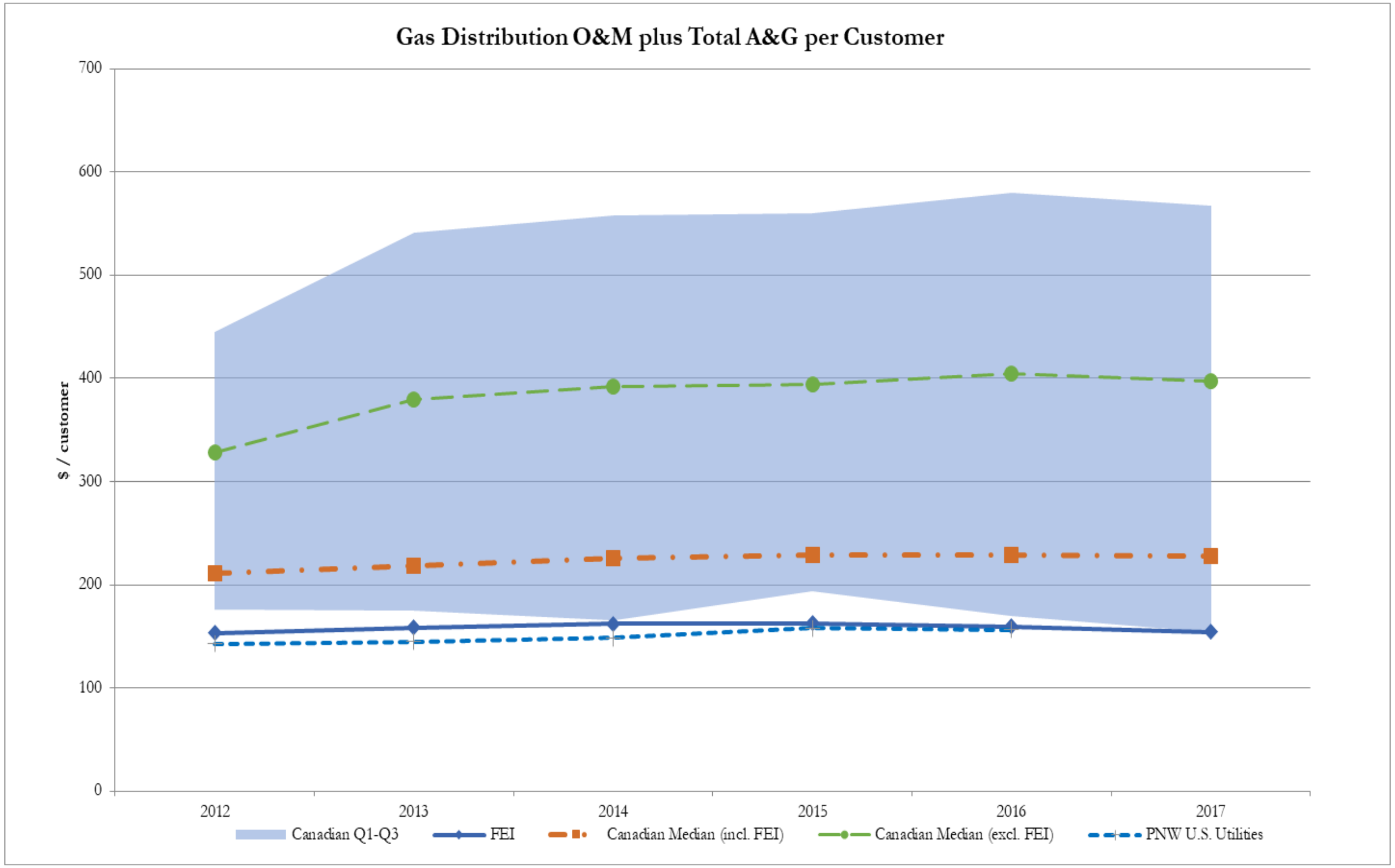


CAGR: 0.75%



CAGR: 1.36%

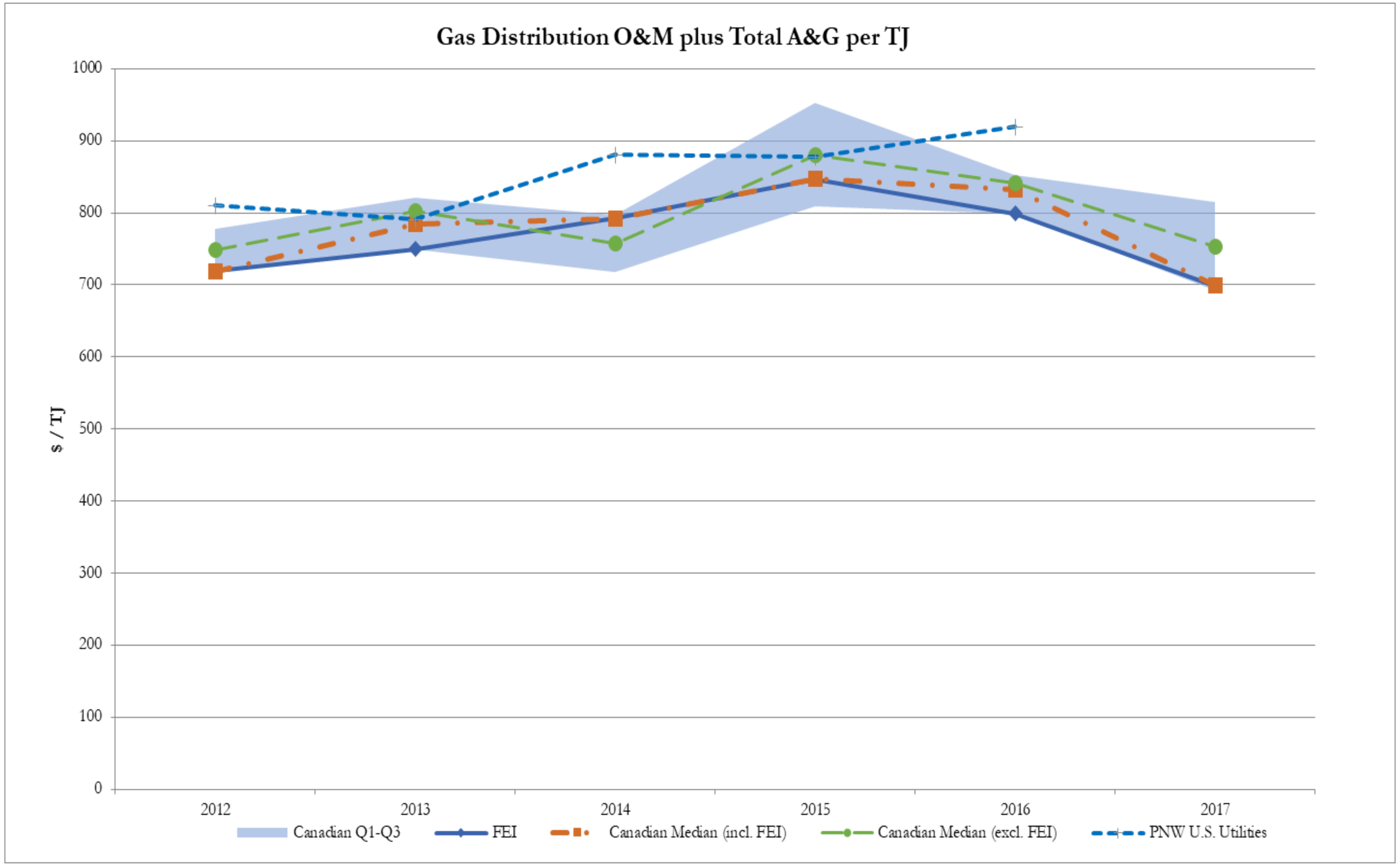
Highlights of FEI Benchmarking Study Distribution O&M plus Total A&G/Customer



CAGRs

- FEI 0.16%
- Canadian Median (incl. FEI) 1.57%
- Canadian Median (excl. FEI) 3.94%

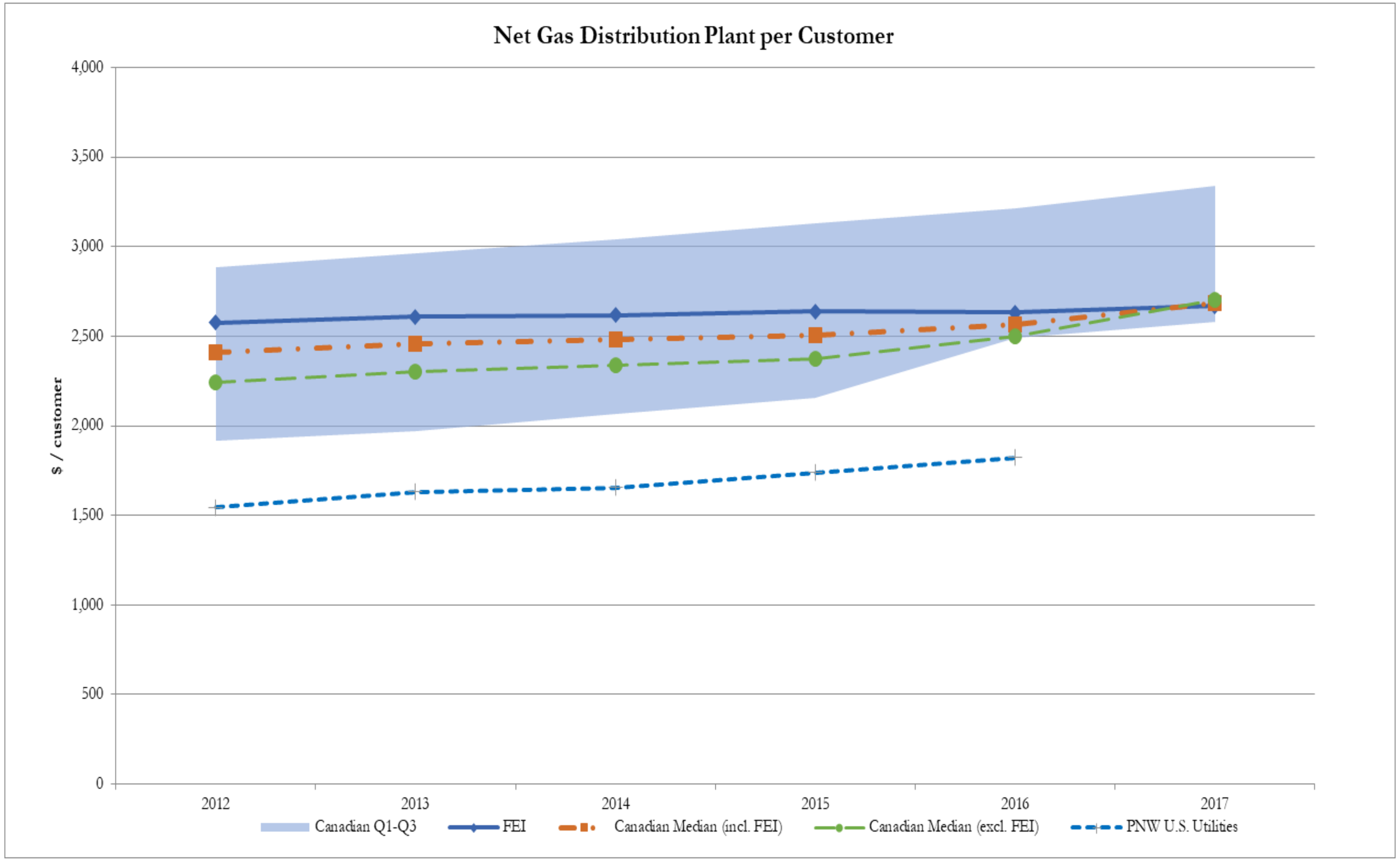
Highlights of FEI Benchmarking Study Distribution O&M plus Total A&G/TJ



CAGRs

- FEI (0.56%)
- Canadian Median (incl. FEI) (0.56%)
- Canadian Median (excl. FEI) 0.15%

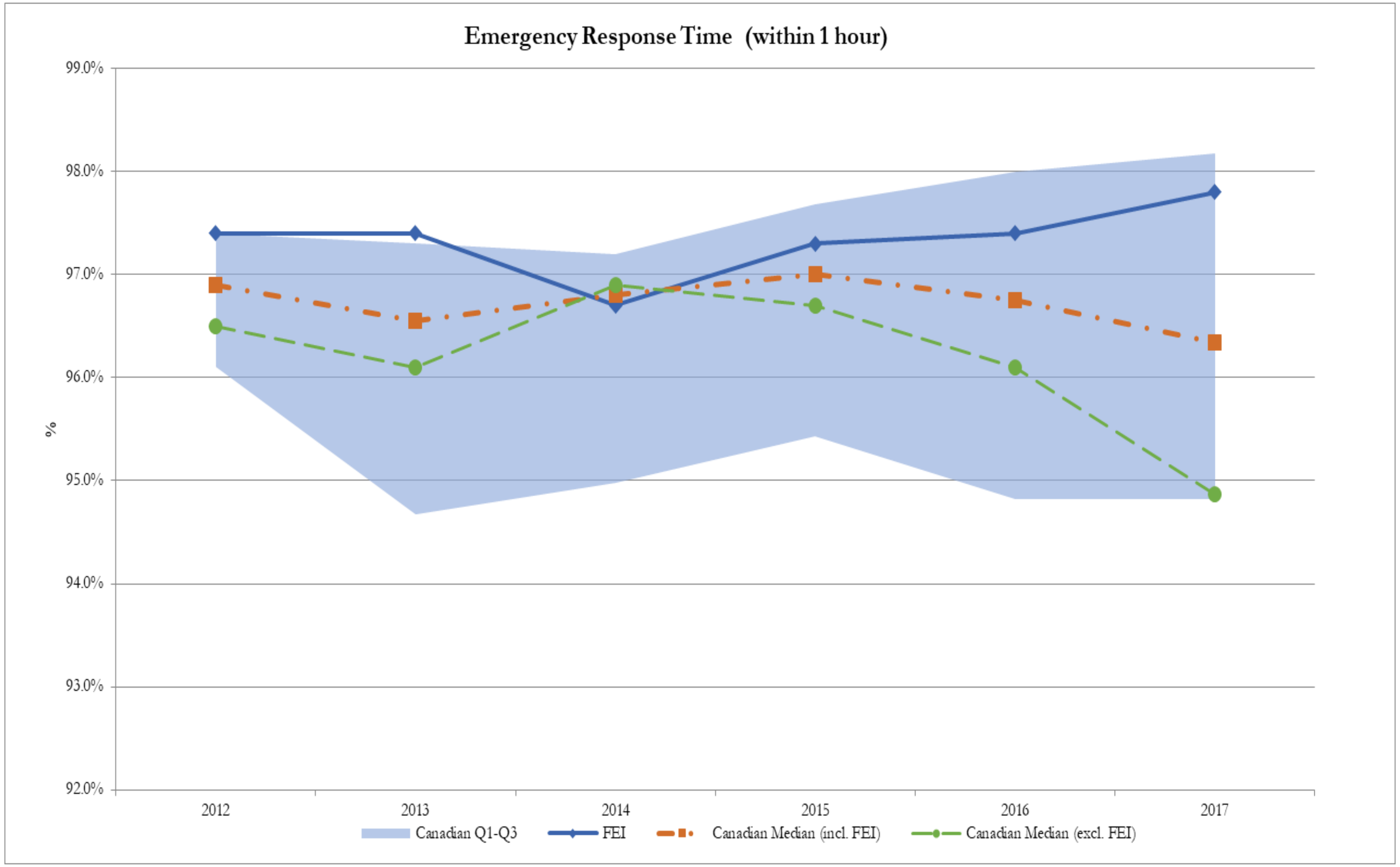
Highlights of FEI Benchmarking Study
Net Distribution Plant/Customer



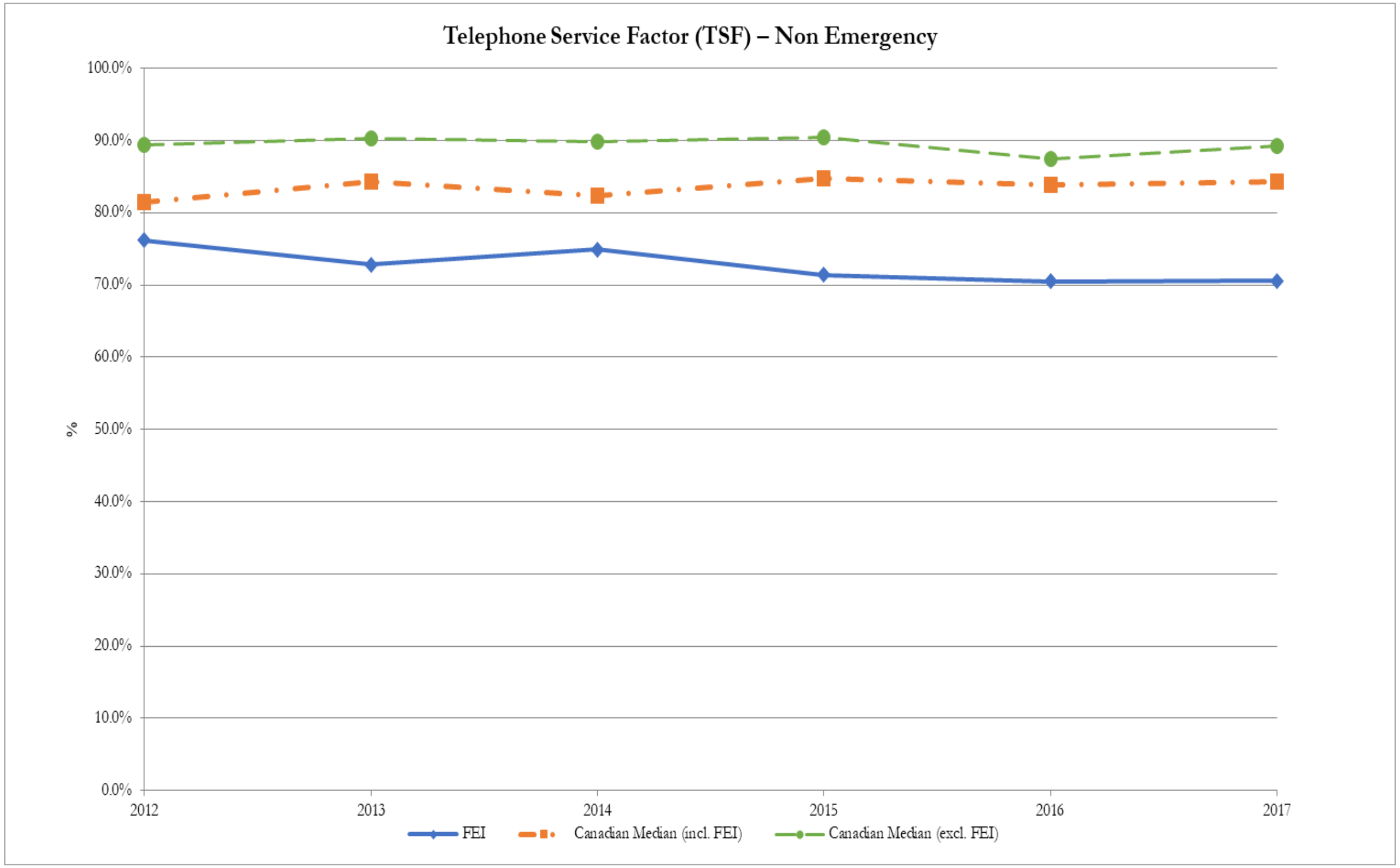
CAGRs

- FEI 0.70%
- Canadian Median (incl. FEI) 2.18%
- Canadian Median (excl. FEI) 3.78%

Highlights of FEI Benchmarking Study
Emergency Response Time



Highlights of FEI Benchmarking Study
Telephone Service Factor – Non-Emergency

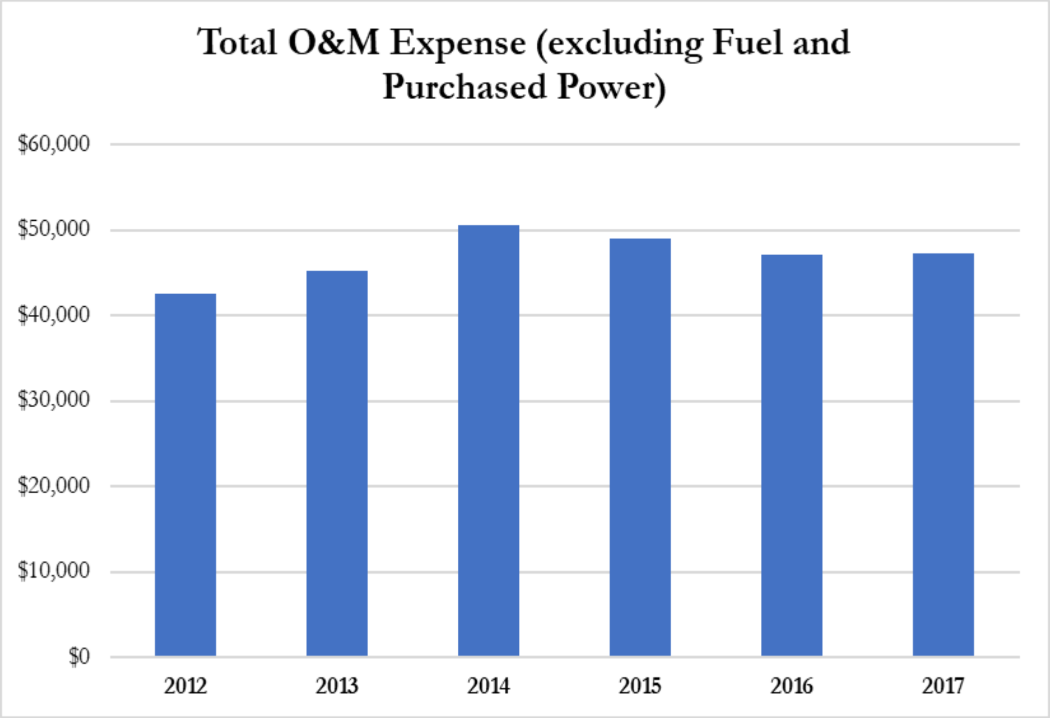


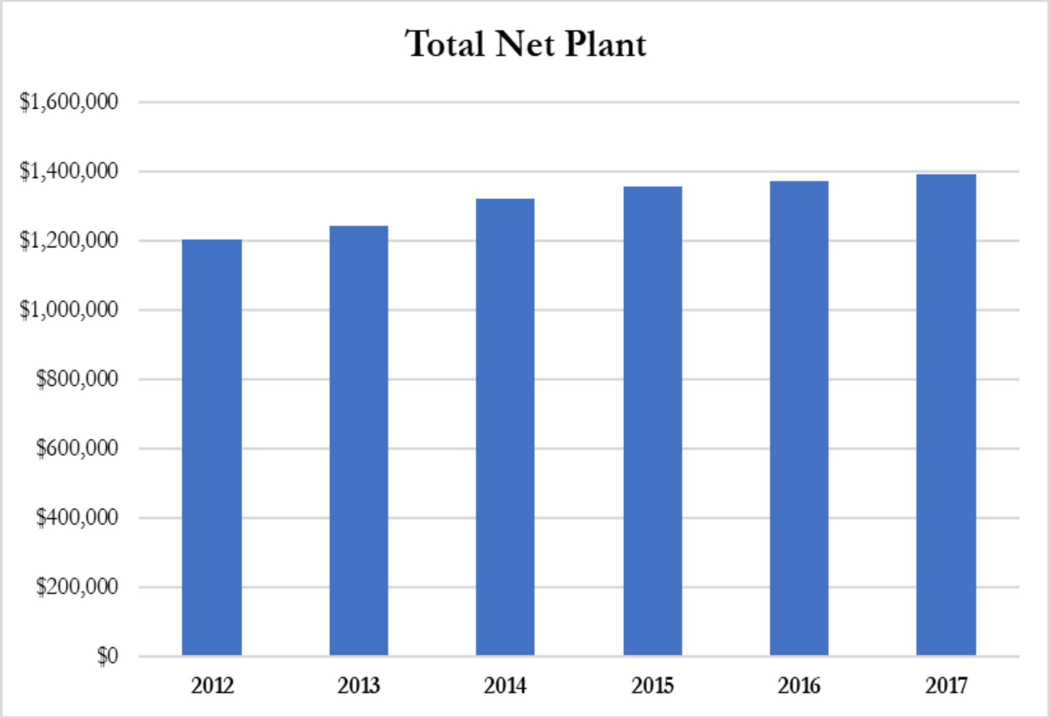
Highlights of FEI Benchmarking Study

% Difference - FEI from Canadian Median	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	-27%	-28%	-28%	-29%	-30%	-32%
Distribution O&M + Total A&G per TJ	0%	-4%	0%	0%	-4%	0%
Distribution O&M + Total A&G per Employee	-27%	-29%	-25%	-21%	-23%	-28%
Distribution Net Plant per Customer	7%	6%	6%	5%	3%	-1%
Distribution Net Plant per Employee	0%	14%	13%	14%	2%	-3%
Administrative and General Expense per Customer	-49%	-50%	-50%	-49%	-51%	-53%
Administrative and General Expense per TJ	0%	0%	0%	0%	0%	0%
Customer Care Expense per Customer	-12%	-12%	-22%	-32%	-31%	-29%
Customer Care Expense per TJ	52%	55%	48%	42%	37%	31%
Interest Expense per Customer	11%	13%	12%	14%	17%	3%
Emergency Response Time (within 1 hr)	1%	1%	0%	0%	1%	2%
Telephone Service Factor - Emergency	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non-Emergency	-6%	-14%	-9%	-16%	-16%	-16%
First Contact Resolution	NA	NA	NA	NA	NA	NA
Telephone Abandon Rate	-9%	-25%	-14%	-13%	0%	-9%
DSM Expenditures (with incentives) per Customer	5%	11%	9%	19%	-4%	-14%
DSM Expenditures (without incentives) per Customer	2%	10%	10%	12%	-12%	-20%
DSM Expenditures (incentives only) per Customer	8%	11%	9%	23%	1%	-10%
Total Emissions tonnes CO2e per Customer	0%	0%	0%	-16%	-20%	NA
Total Emissions tonnes CO2e per TJ	3%	5%	17%	0%	0%	NA

Highlights of FBC Benchmarking Study

Highlights of FBC Benchmarking Study

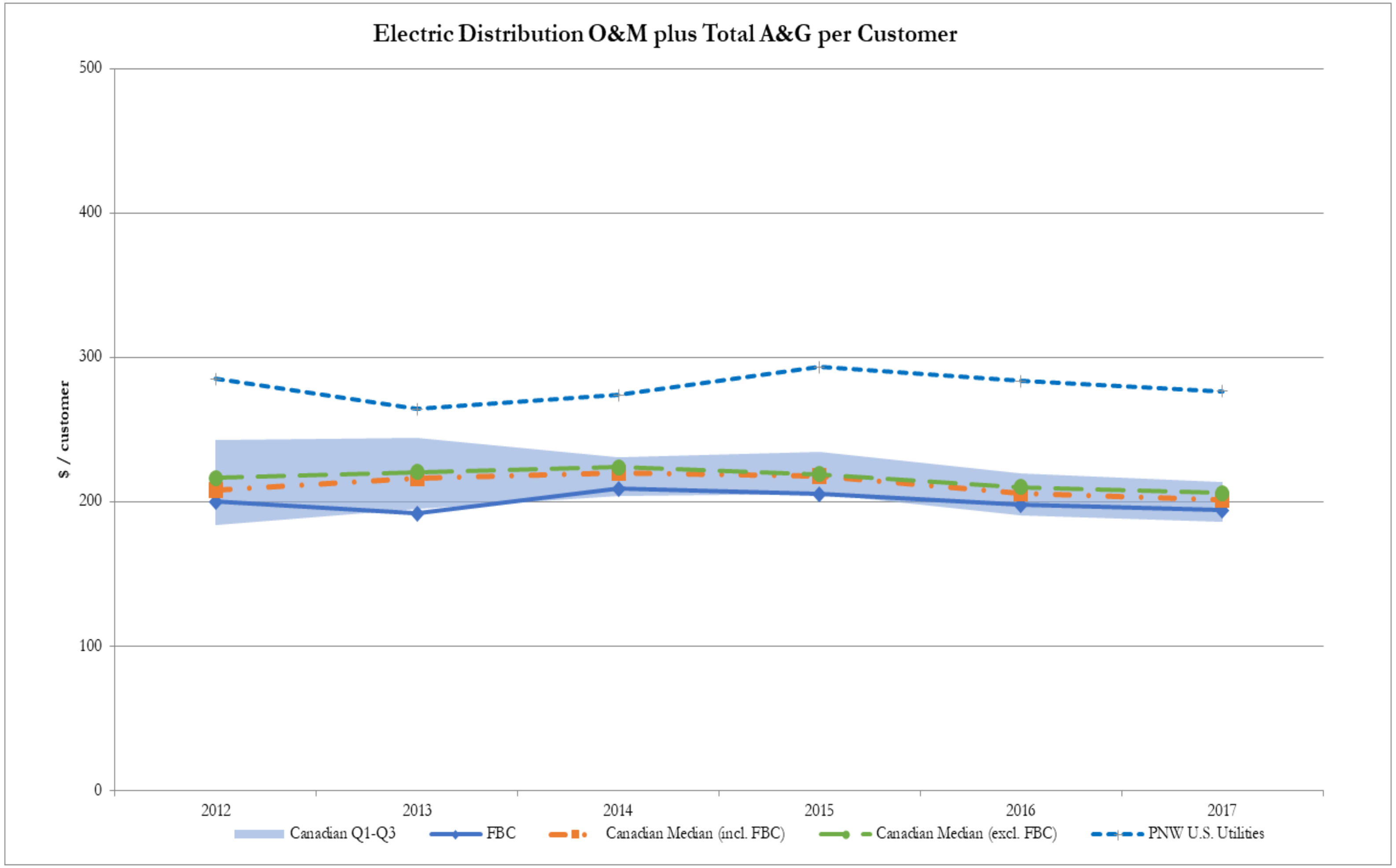




CAGR: 2.08%

CAGR: 2.95%

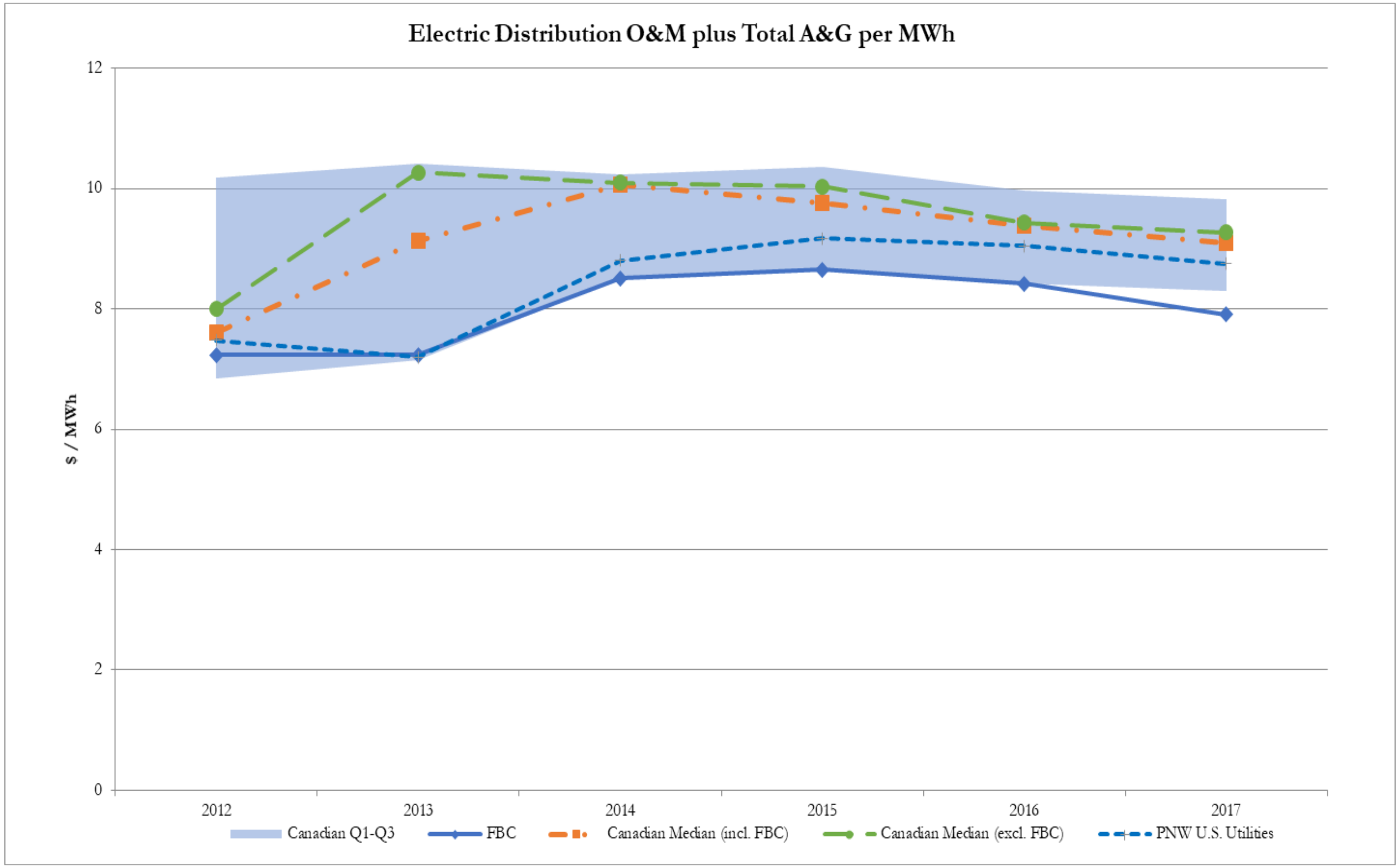
Highlights of FBC Benchmarking Study
Distribution O&M plus Total A&G/Customer



CAGRs

- FBC (0.62%)
- Canadian Median (incl. FBC) (0.66%)
- Canadian Median (excl. FBC) (0.98%)
- PNW U.S. Utilities (0.60%)

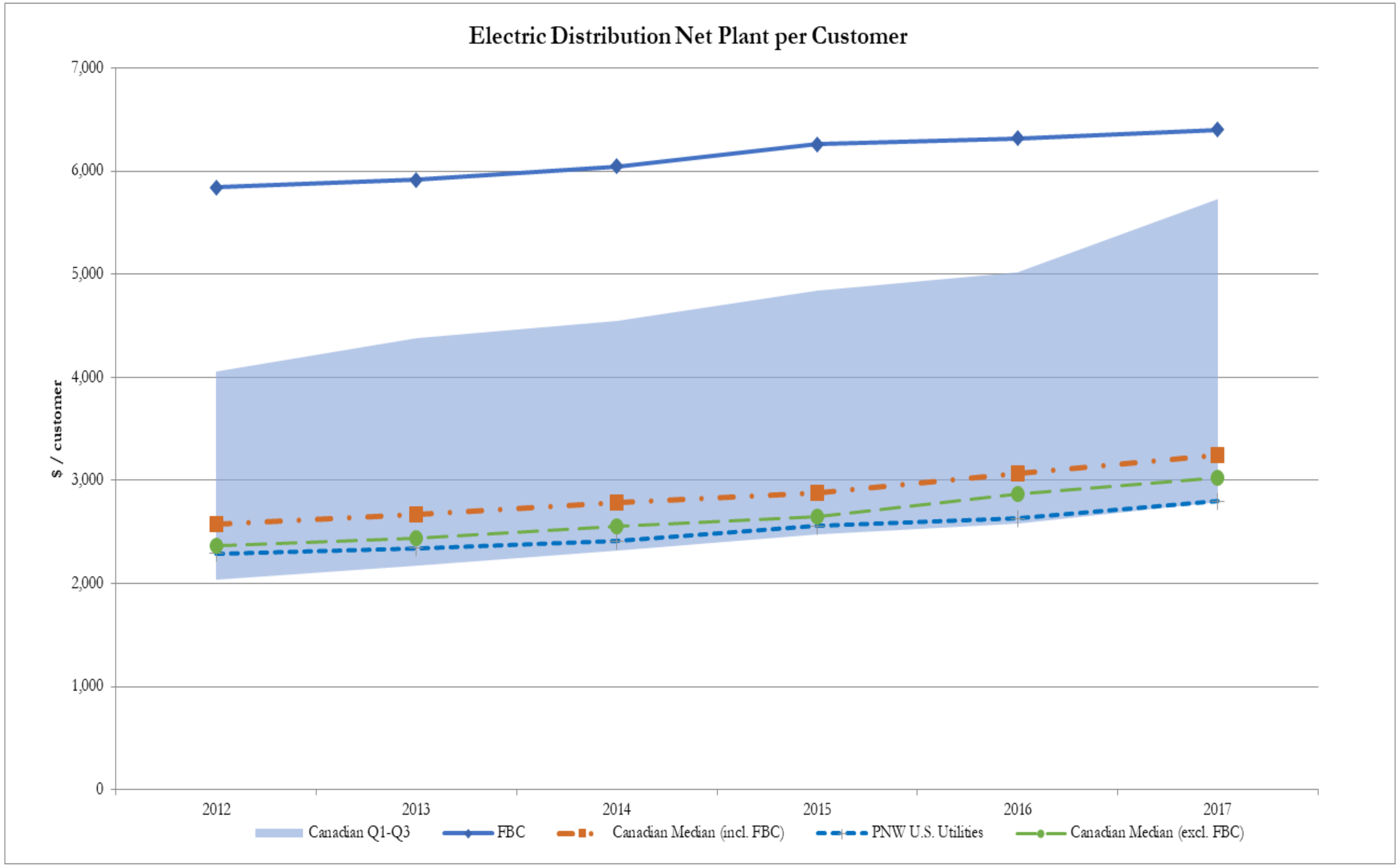
Highlights of FBC Benchmarking Study Distribution O&M plus Total A&G/MWh



CAGRs

- FBC 1.80%
- Canadian Median (incl. FBC) 3.64%
- Canadian Median (excl. FBC) 3.00%
- PNW U.S. Utilities 3.19%

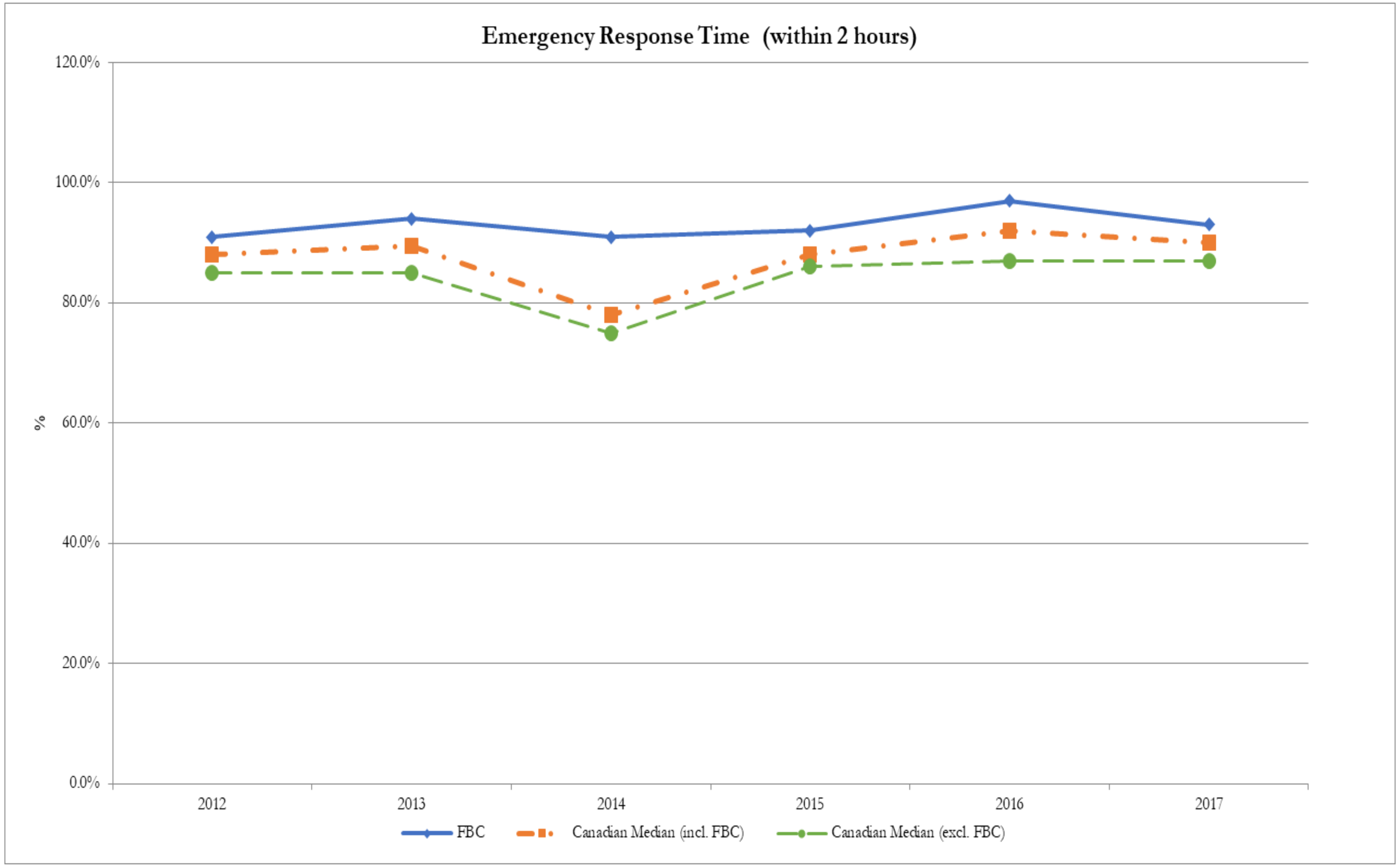
Highlights of FBC Benchmarking Study Net Distribution Plant/Customer



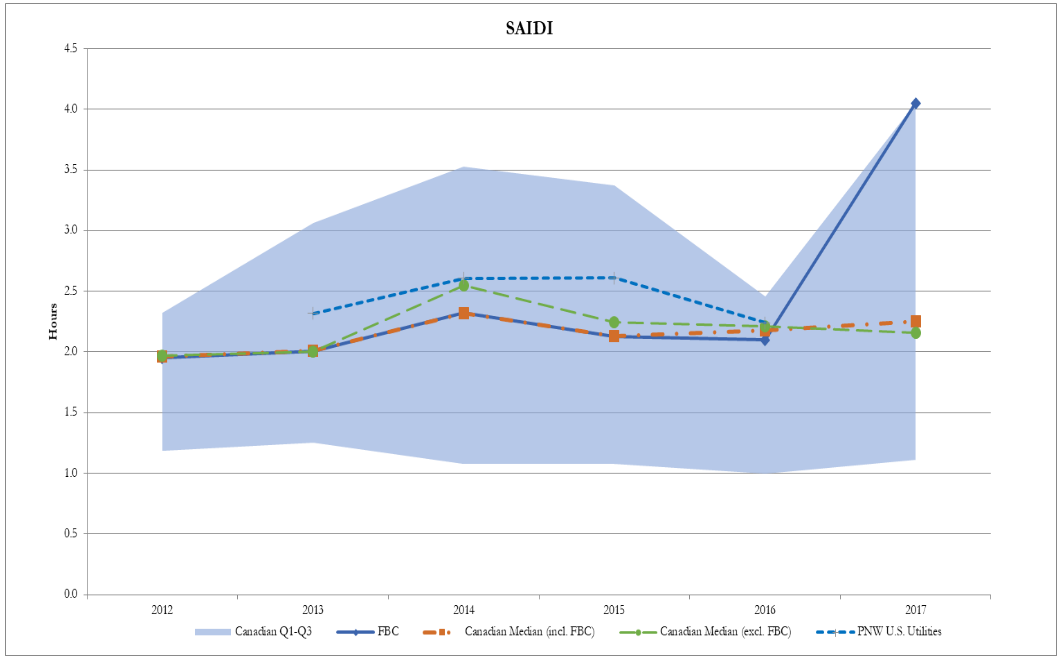
CAGRs

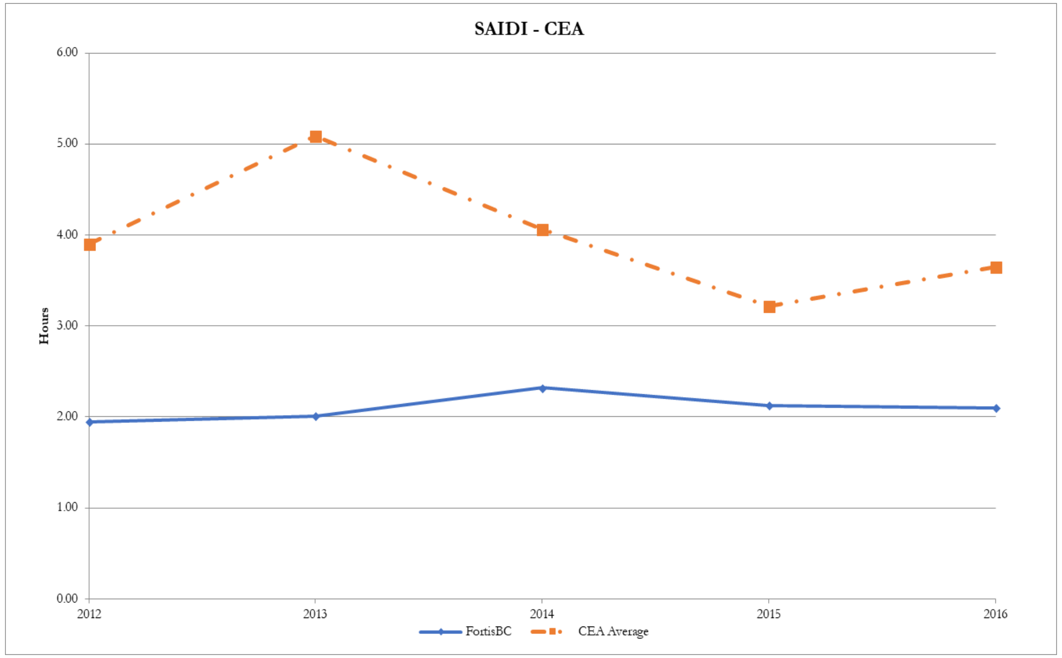
- FBC 1.85%
- Canadian Median (incl. FBC) 4.73%
- Canadian Median (excl. FBC) 5.07%
- PNW U.S. Utilities 4.08%

Highlights of FBC Benchmarking Study
Emergency Response Time

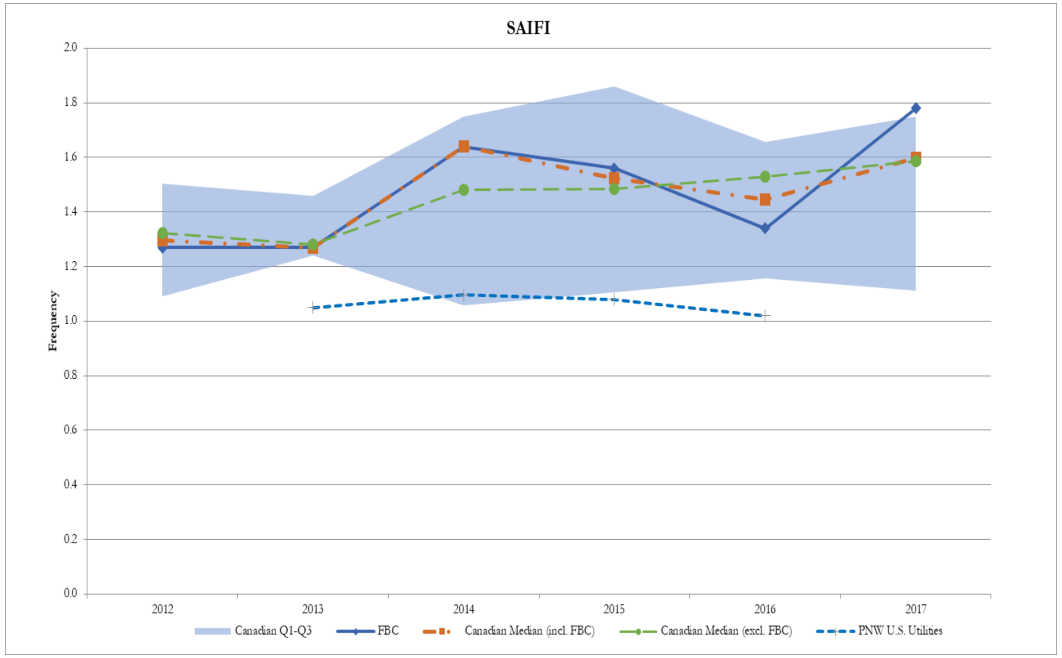


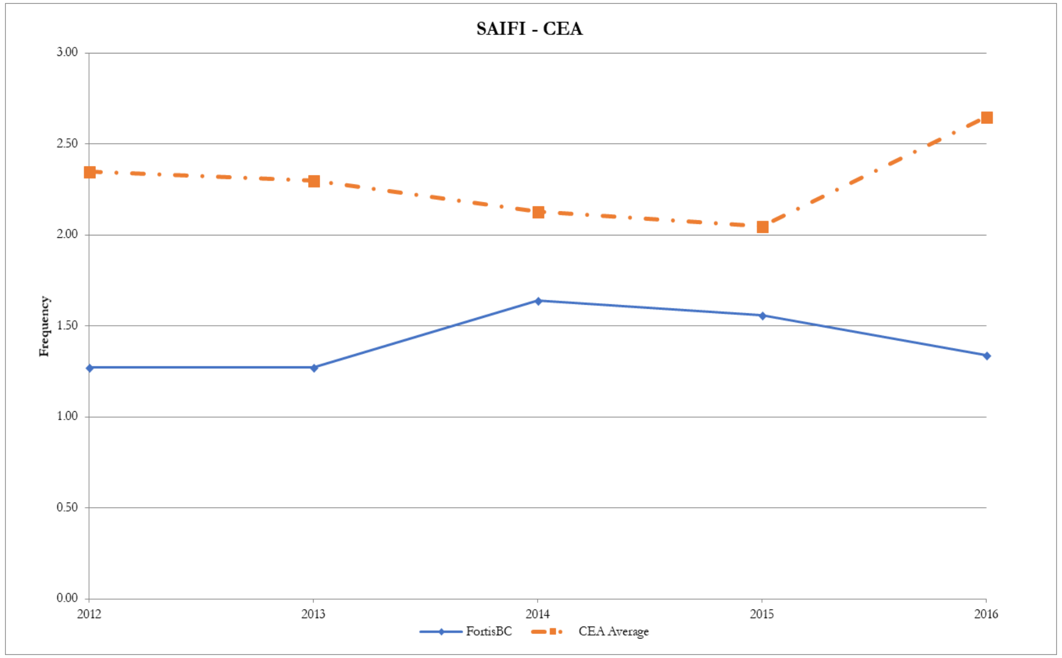
Highlights of FBC Benchmarking Study
SAIDI



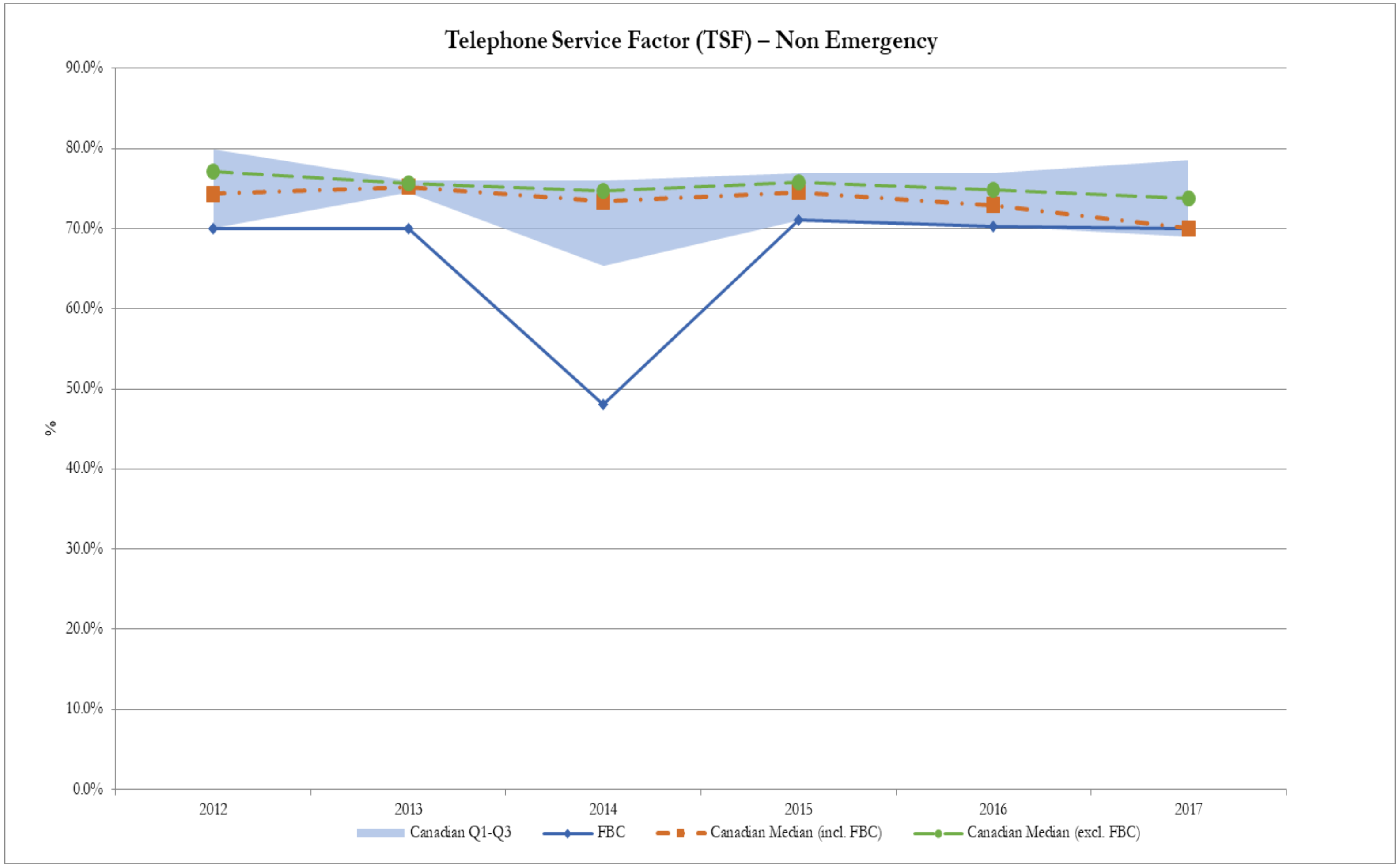


Highlights of FBC Benchmarking Study
SAIFI





Highlights of FBC Benchmarking Study
Telephone Service Factor – Non-Emergency



Highlights of FBC Benchmarking Study

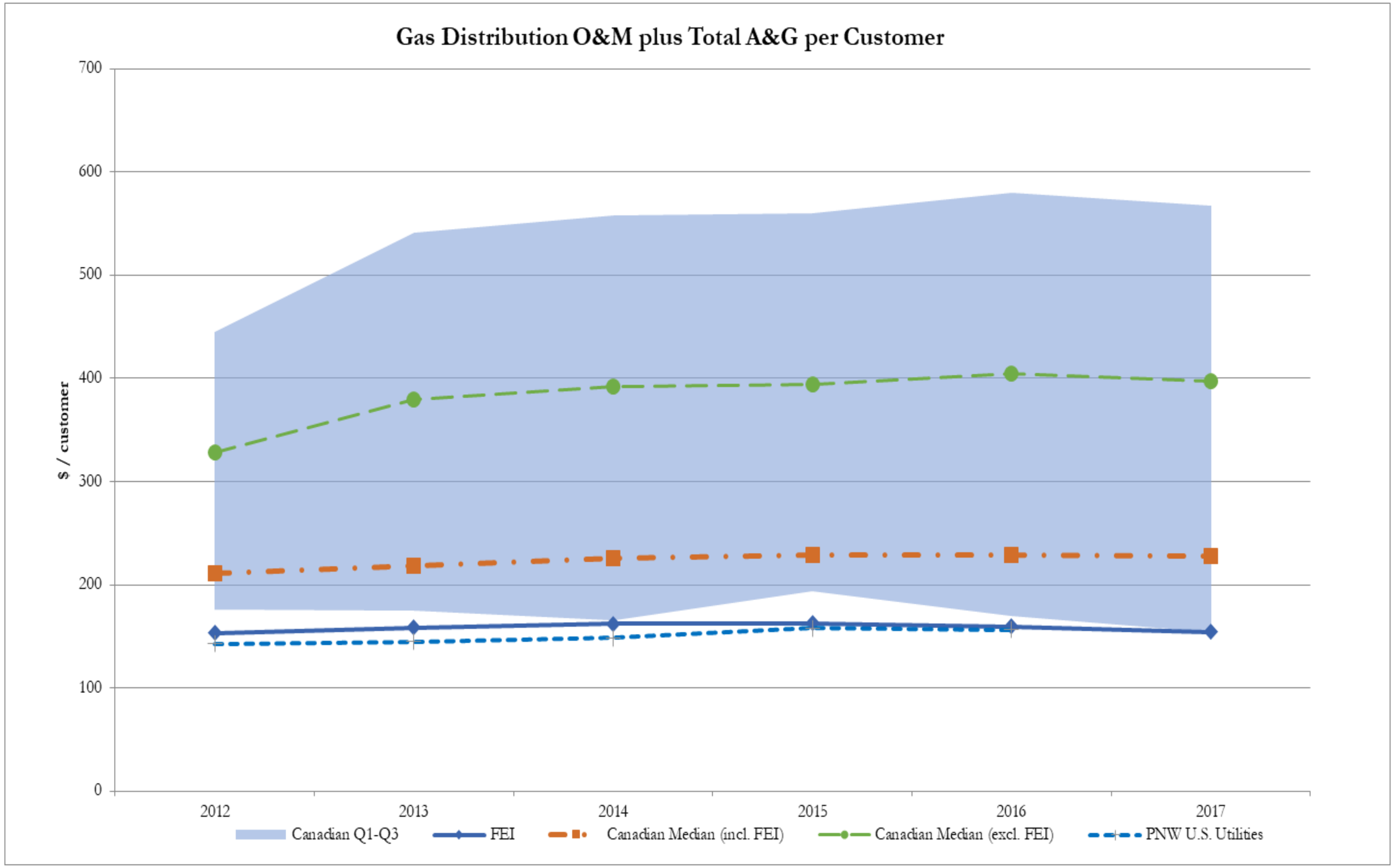
% Difference - FBC from Canadian Median	2012	2013	2014	2015	2016	2017
Distribution O&M + Total A&G per Customer	-4%	-11%	-5%	-6%	-4%	-4%
Distribution O&M + Total A&G per MWh	-5%	-21%	-15%	-11%	-10%	-13%
Distribution O&M + Total A&G per Employee	-52%	-41%	-39%	-45%	-40%	-48%
Distribution Net Plant per Customer	127%	122%	117%	117%	106%	98%
Distribution Net Plant per Employee	10%	43%	22%	12%	11%	0%
Administrative and General Expense per Customer	-4%	-11%	-2%	-3%	0%	1%
Administrative and General Expense per MWh	-4%	-10%	0%	-14%	-3%	-2%
Customer Care Expense per Customer	44%	62%	63%	42%	19%	30%
Customer Care Expense per MWh	29%	49%	55%	51%	17%	17%
Interest Expense per Customer	138%	123%	122%	108%	87%	85%
Emergency Response Time (within 2 hrs)	3%	5%	17%	5%	5%	3%
SAIDI	-1%	0%	0%	0%	-4%	80%
SAIFI	-2%	0%	0%	2%	-7%	11%
Generator Forced Outage Rate	NA	NA	NA	NA	NA	NA
Telephone Service Factor - Non Emergency	-6%	-7%	-35%	-5%	-4%	0%
First Contact Resolution	NA	-14%	-12%	-10%	-7%	-5%
Telephone Abandon Rate	-8%	-13%	376%	0%	30%	-3%
DSM Expenditures (with incentives) per Customer	69%	29%	0%	0%	36%	101%
DSM Expenditures (without incentives) per Customer	42%	26%	-9%	16%	52%	21%
DSM Expenditures (incentives only) per Customer	73%	57%	37%	1%	21%	54%

Appendices

Appendix – FEI Charts

1. Distribution O&M plus Total A&G/Customer
2. Distribution O&M plus Total A&G /TJ
3. Distribution O&M plus Total A&G /Employee
4. Net Distribution Plant/Customer
5. Net Distribution Plant/Employee
6. Total A&G/Customer
7. Total A&G/TJ
8. Gas Delivered per Employee
9. Employees per Thousand Customers
10. Customer Care Expense/Customer
11. Customer Care Expense/TJ
12. Interest Expense/Customer
13. Emergency Response Time
14. Telephone Service Factor – Emergency
15. Telephone Service Factor – Non-Emergency
16. First Contact Resolution
17. Telephone Abandonment Rates
18. DSM Expenditures (with incentives)/Customer
19. DSM Expenditures (without incentives)/Customer
20. DSM Expenditures (incentives only)/Customer
21. GHG Emissions/Customer
22. GHG Emissions/TJ

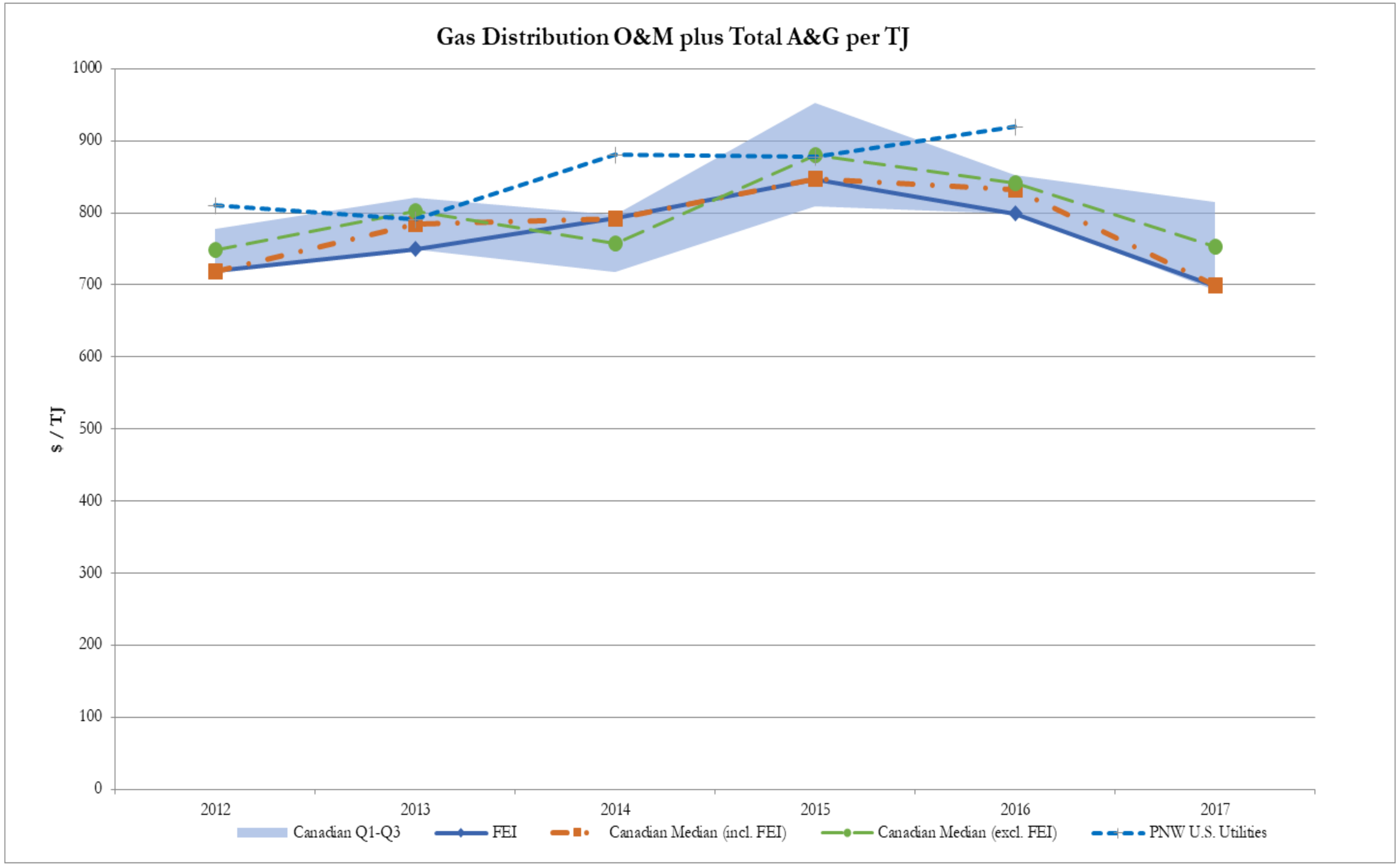
Appendix – FEI
1. Distribution O&M plus Total A&G/Customer



CAGRs

- FEI
  0.16%
- Canadian Median (incl. FEI)
  1.57%
- Canadian Median (excl. FEI)
  3.94%

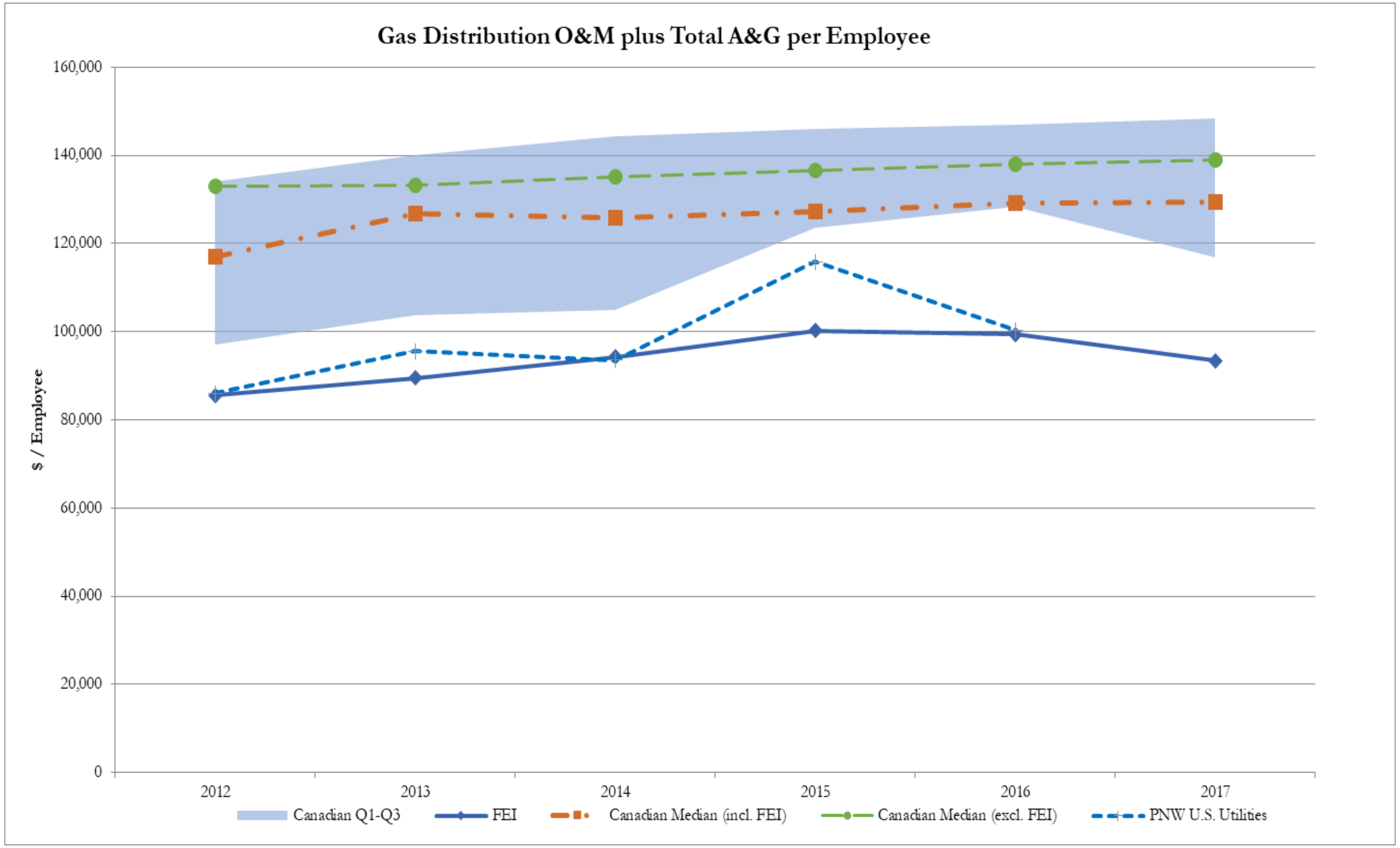
Appendix – FEI
2. Distribution O&M plus Total A&G/TJ



CAGRs

- FEI (0.56%)
- Canadian Median (incl. FEI) (0.56%)
- Canadian Median (excl. FEI) 0.15%

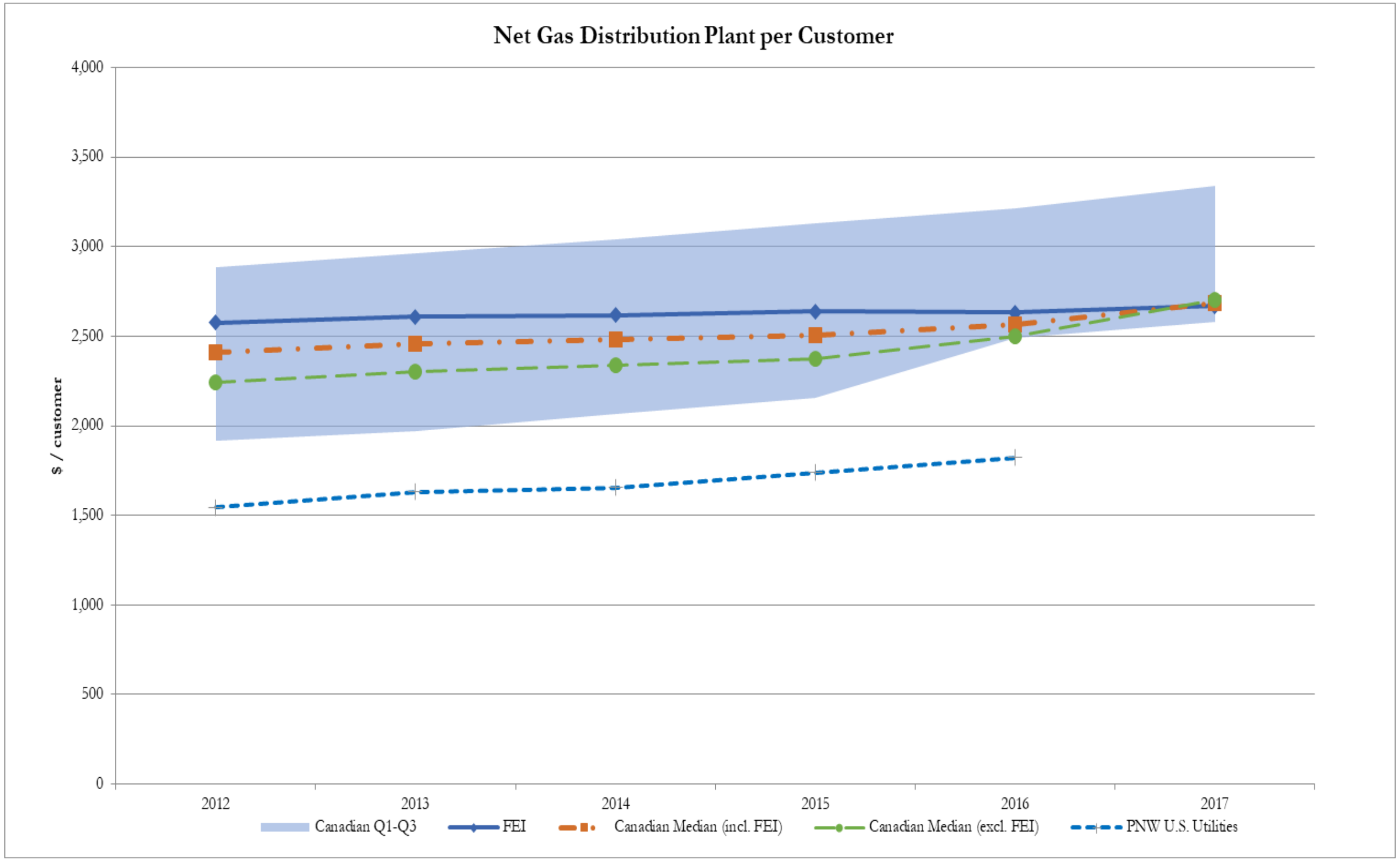
Appendix – FEI
3. Distribution O&M plus Total A&G/Employee



CAGRs

- FEI 1.76%
- Canadian Median (incl. FEI) 2.07%
- Canadian Median (excl. FEI) 0.89%

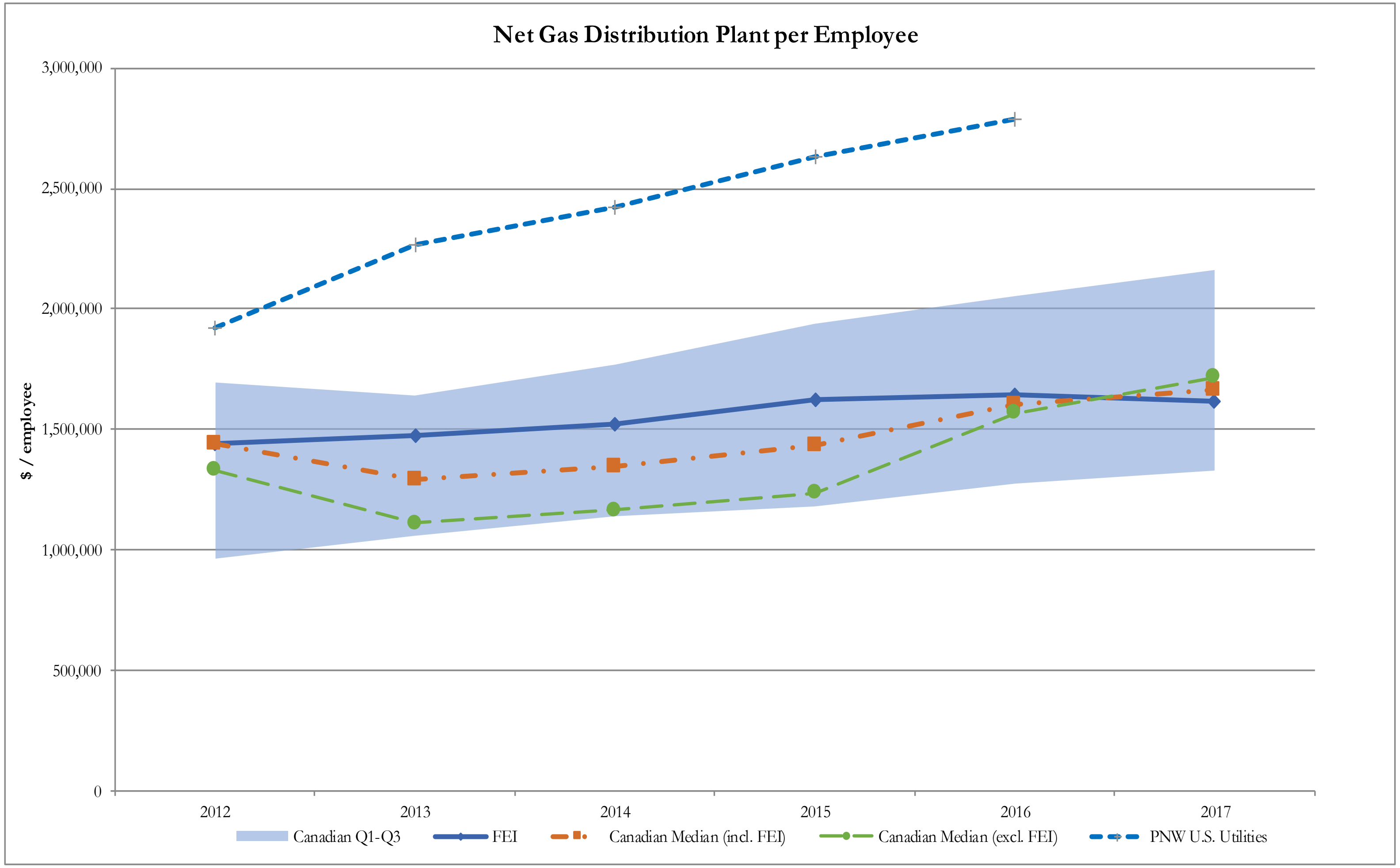
Appendix – FEI
4. Net Distribution Plant/Customer



CAGRs

- FEI 0.70%
- Canadian Median (incl. FEI) 2.18%
- Canadian Median (excl. FEI) 3.78%

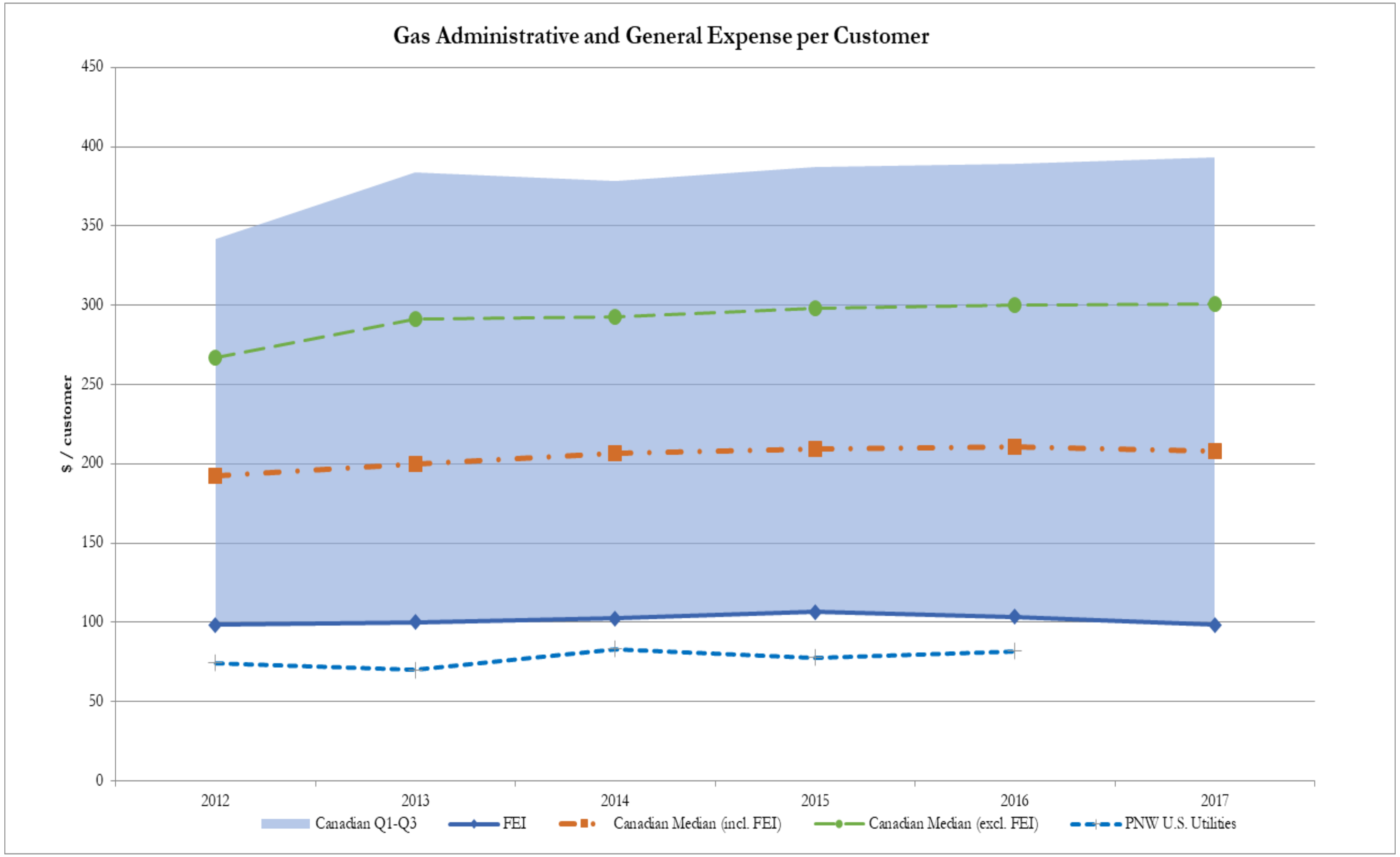
Appendix – FEI
5. Net Distribution Plant/Employee



CAGRs

- FEI 2.31%
- Canadian Median (incl. FEI) 2.93%
- Canadian Median (excl. FEI) 5.23%

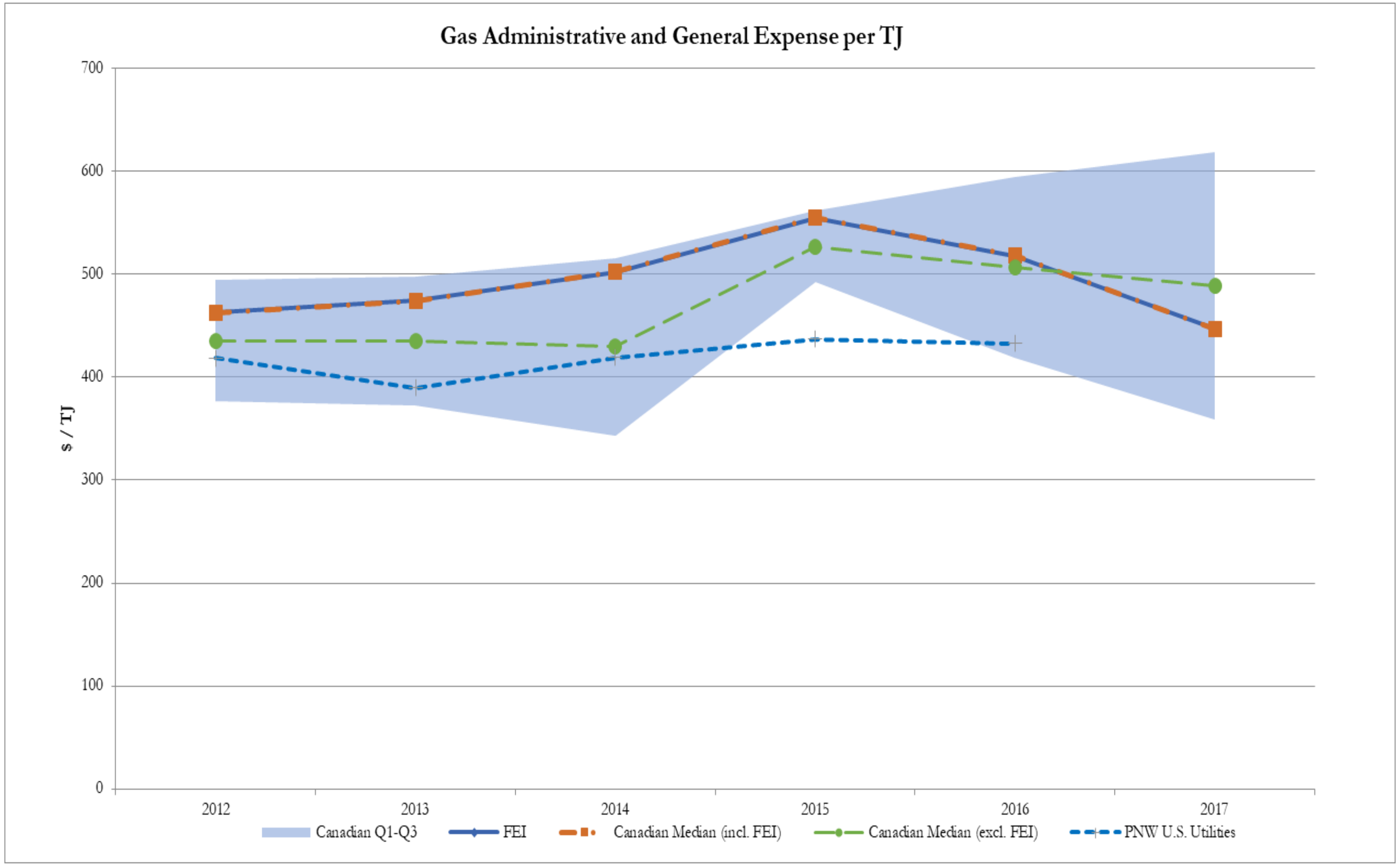
Appendix – FEI
6. Total A&G/Customer



CAGRs

- FEI
  0.02%
- Canadian Median (incl. FEI)
  1.59%
- Canadian Median (excl. FEI)
  2.41%

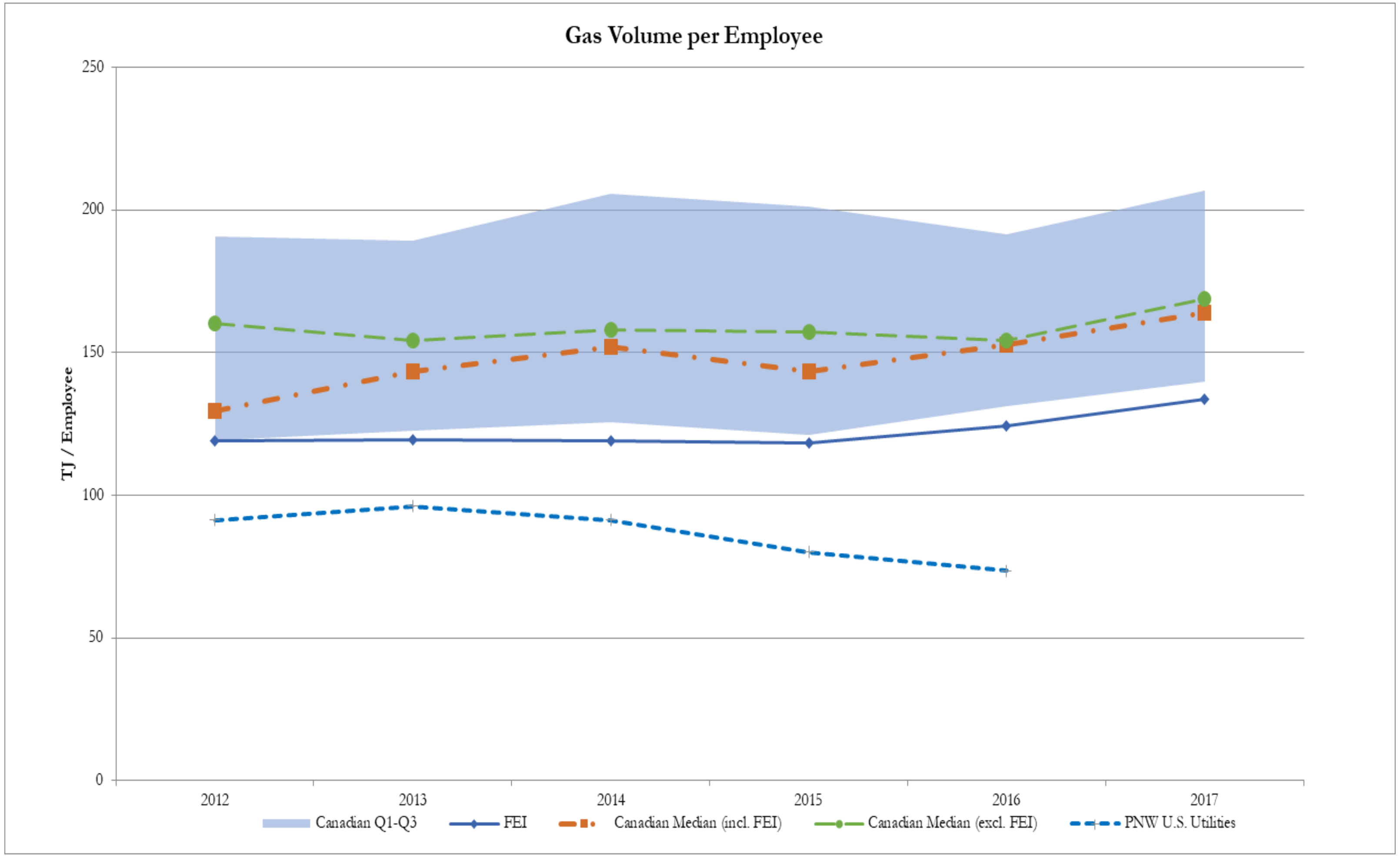
Appendix – FEI
7. Total A&G/TJ



CAGRs

- FEI (0.71%)
- Canadian Median (incl. FEI) (0.71%)
- Canadian Median (excl. FEI) 2.36%

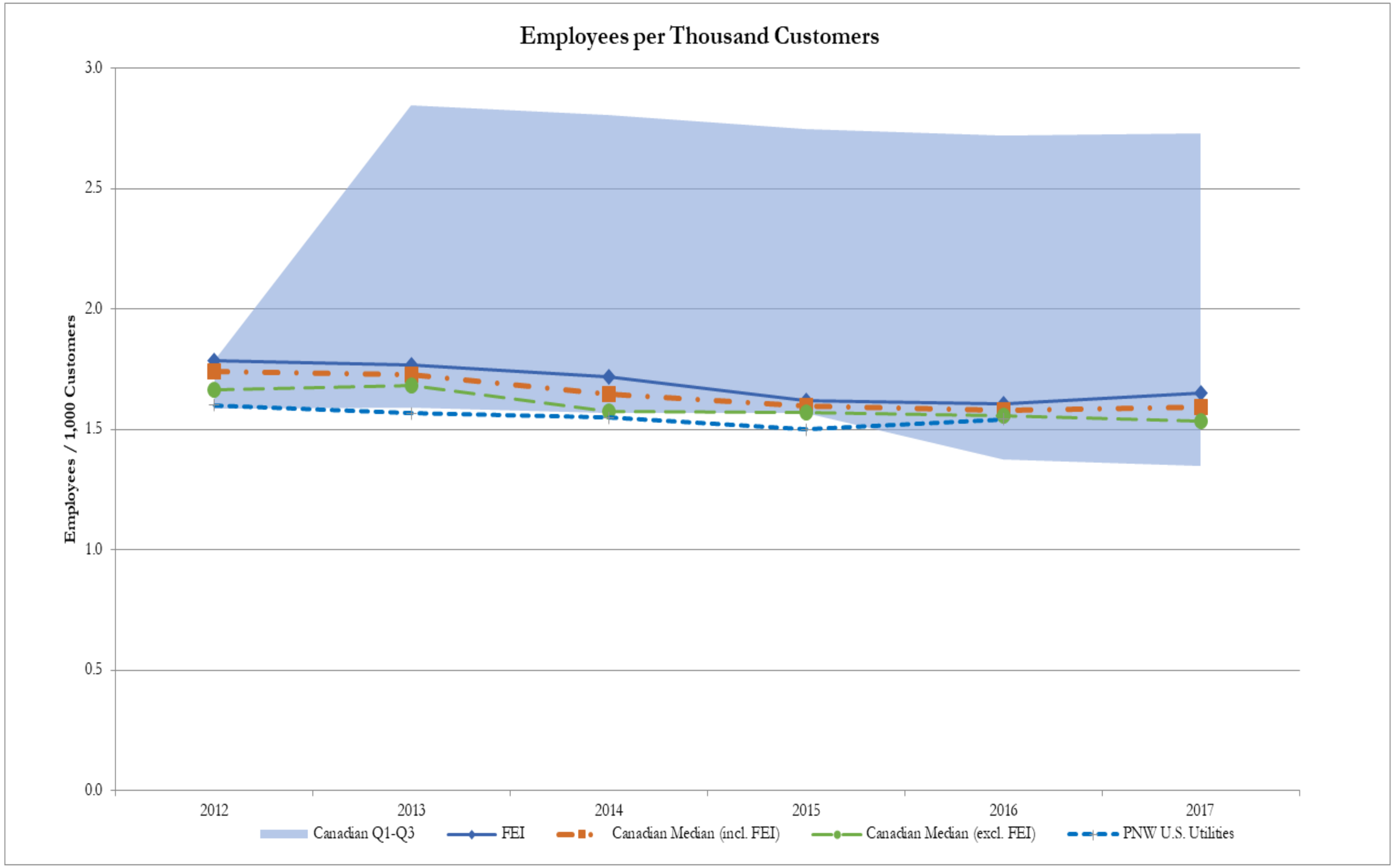
Appendix – FEI
8. Gas Delivered per Employee



CAGRs

- FEI
  2.34%
- Canadian Median (incl. FEI)
  4.79%
- Canadian Median (excl. FEI)
  1.05%

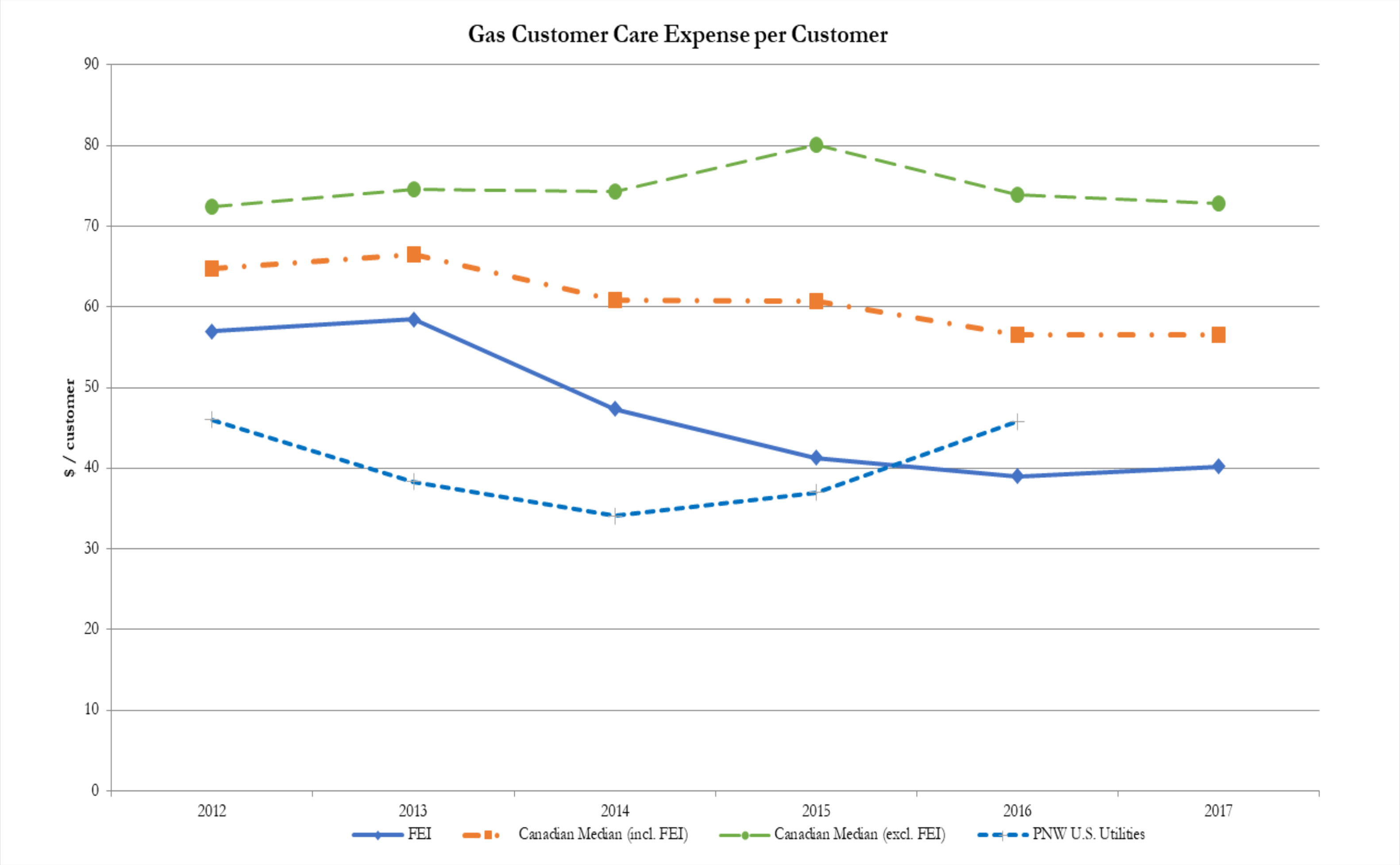
Appendix – FEI
9. Employees per Thousand Customers



CAGRs

- FEI (1.57%)
- Canadian Median (incl. FEI) (1.79%)
- Canadian Median (excl. FEI) (1.60%)

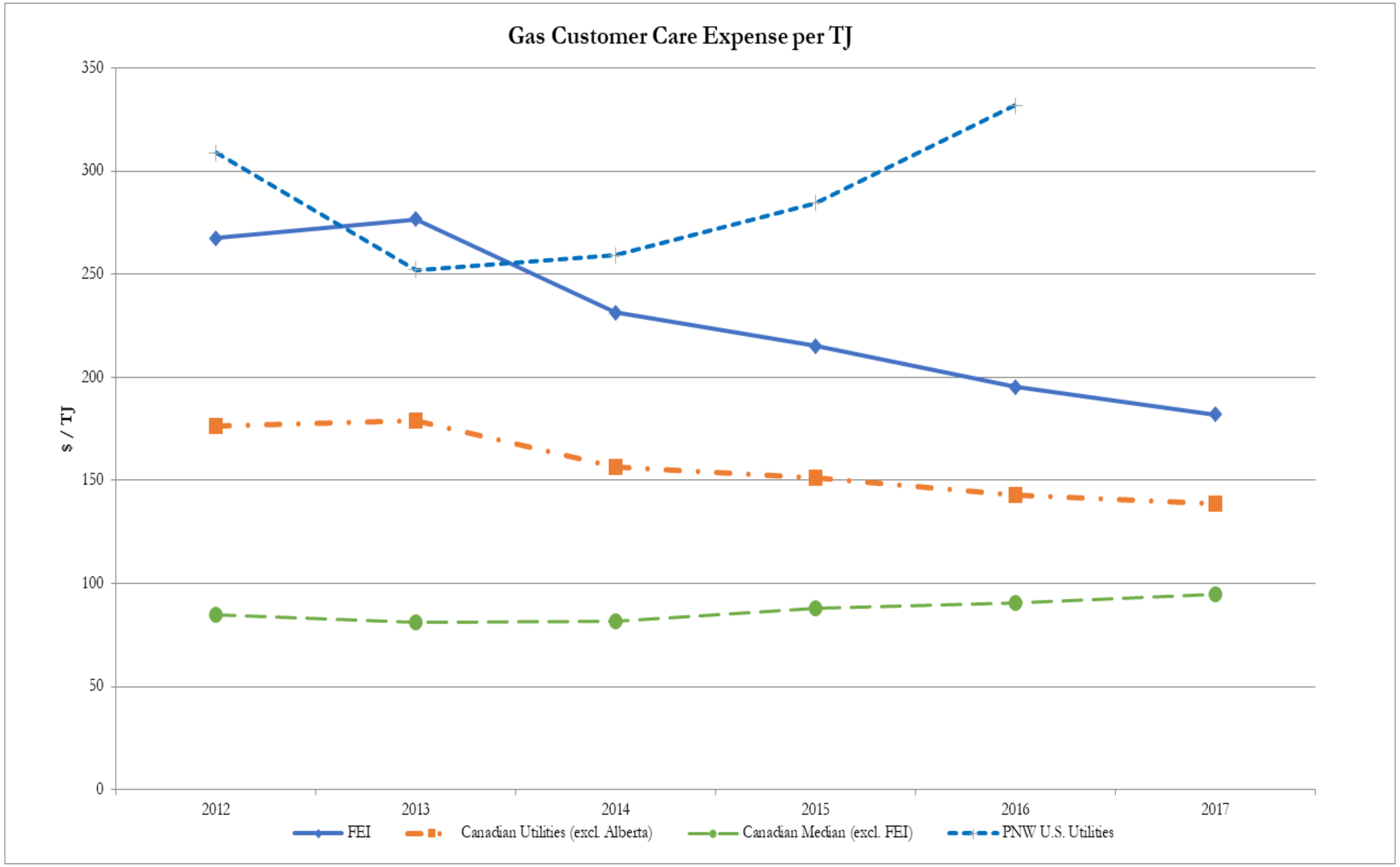
Appendix – FEI
10. Customer Care Expense/Customer



CAGRs

- FEI (6.73%)
- Canadian Median (incl. FEI) (2.67%)
- Canadian Median (excl. FEI) 0.10%

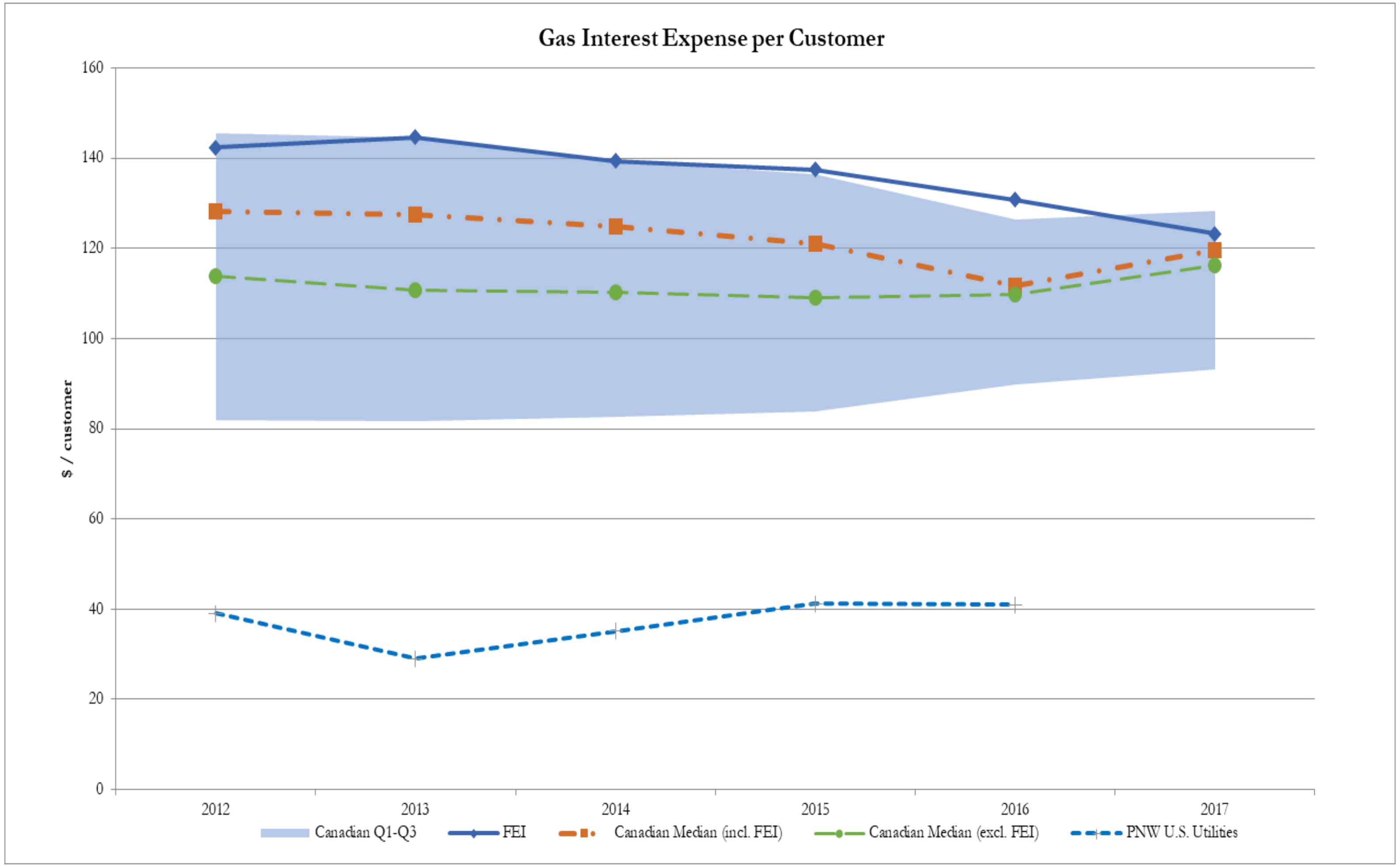
Appendix – FEI
11. Customer Care Expense/TJ



CAGRs

- FEI (7.40%)
- Canadian Median (incl. FEI) (4.70%)
- Canadian Median (excl. FEI) 2.25%

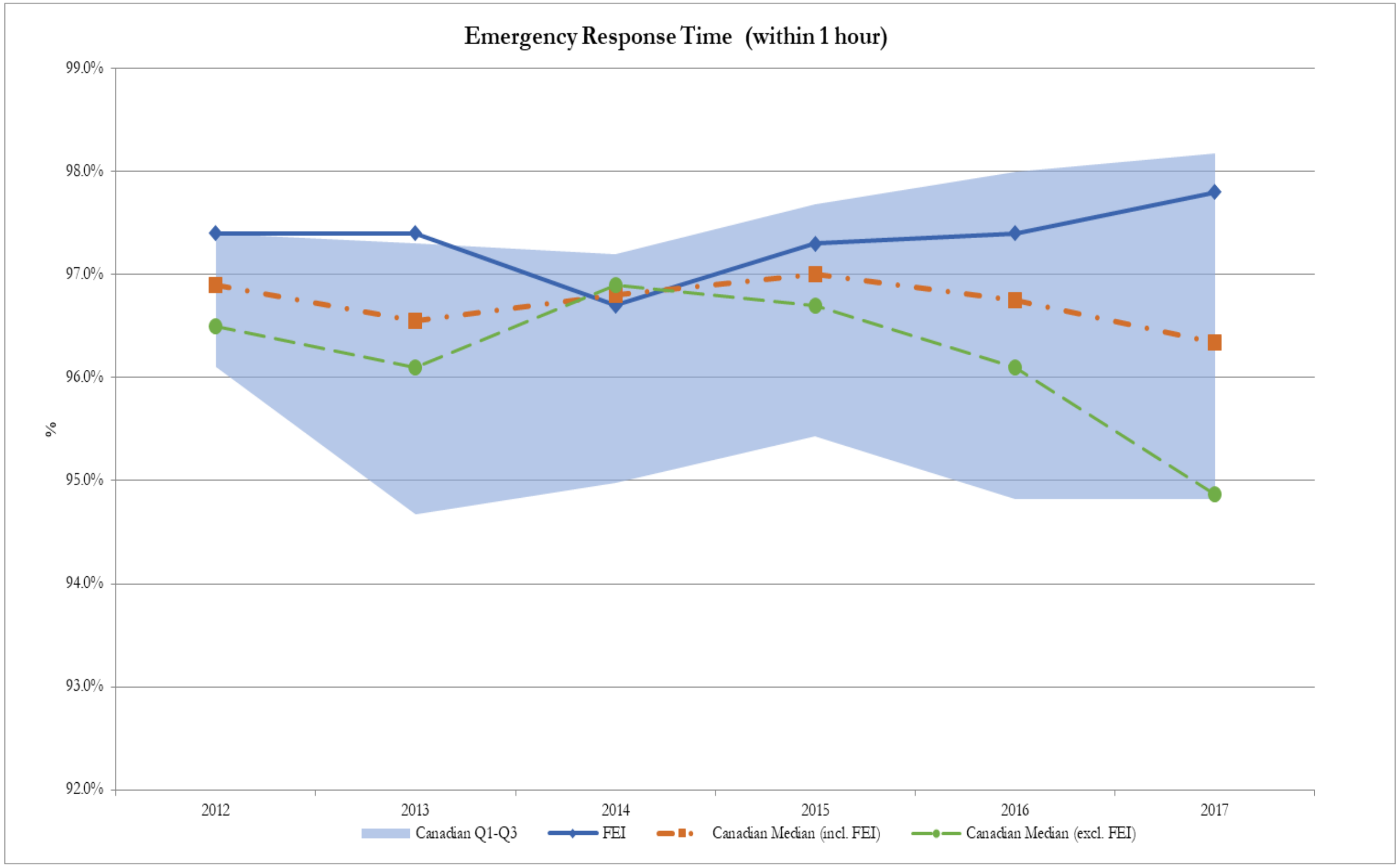
Appendix – FEI
12. Interest Expense/Customer



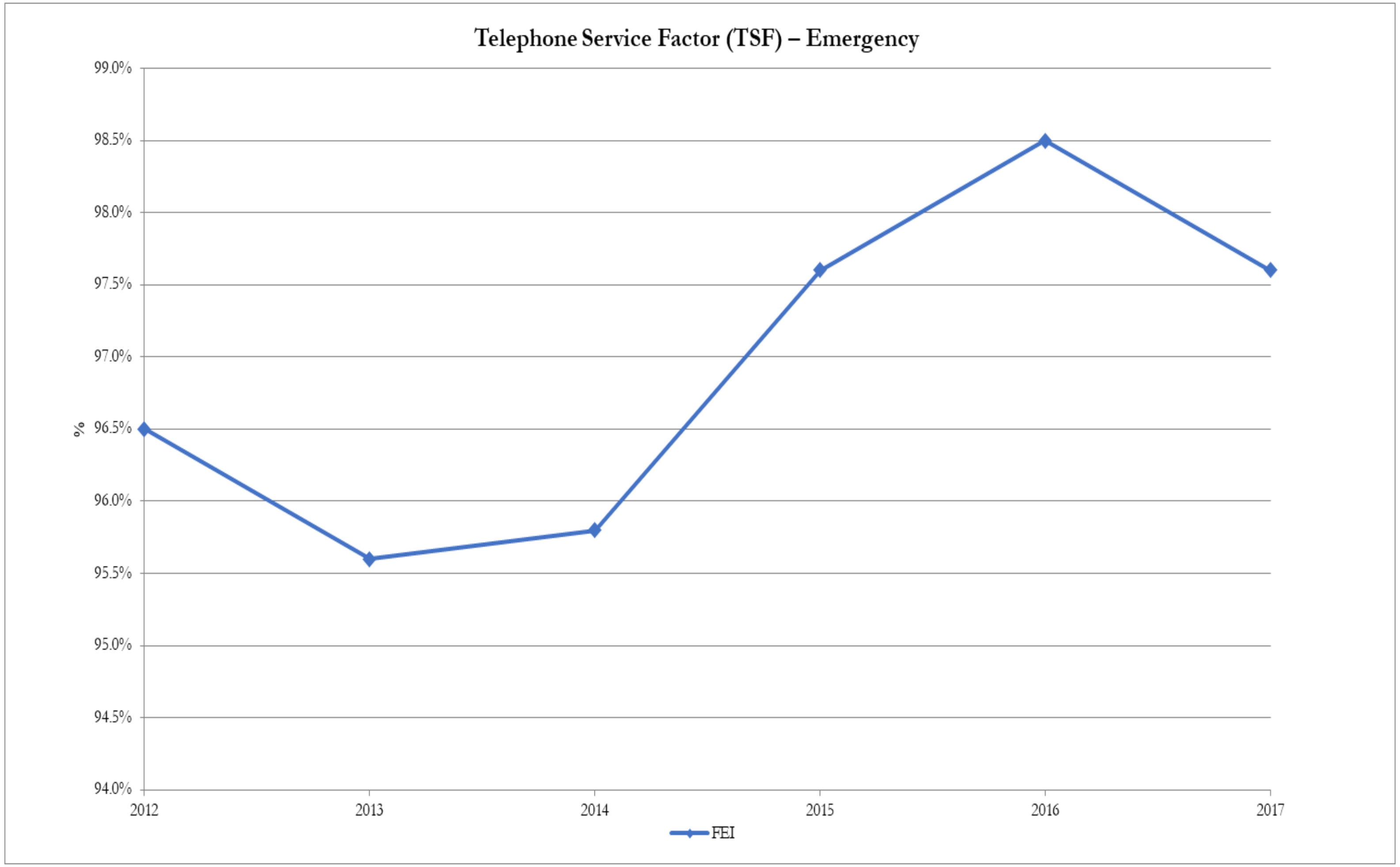
CAGRs

- FEI (2.84%)
- Canadian Median (incl. FEI) (1.36%)
- Canadian Median (excl. FEI) 0.38%

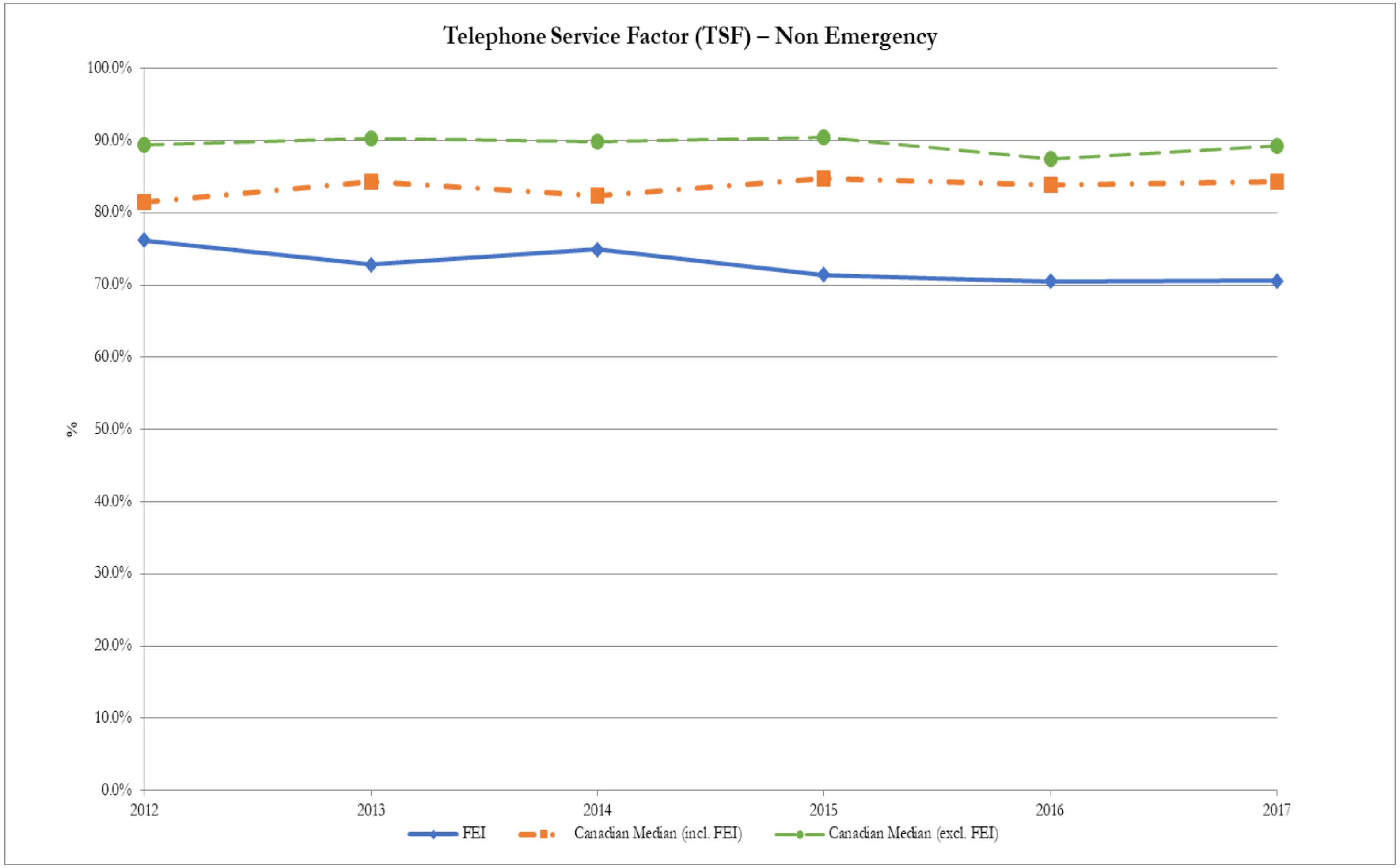
Appendix – FEI
13. Emergency Response Time



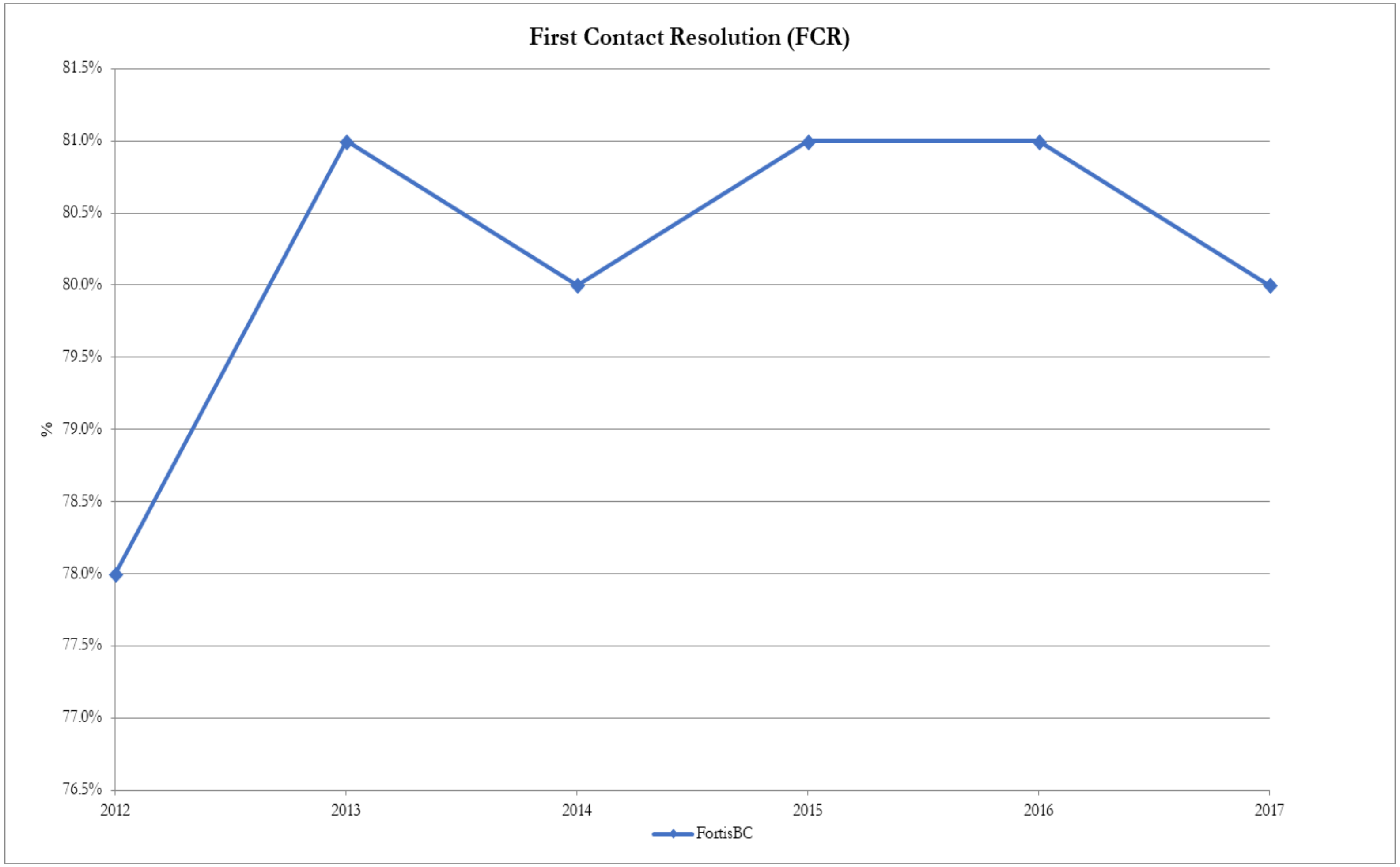
Appendix – FEI
14. Telephone Service Factor - Emergency



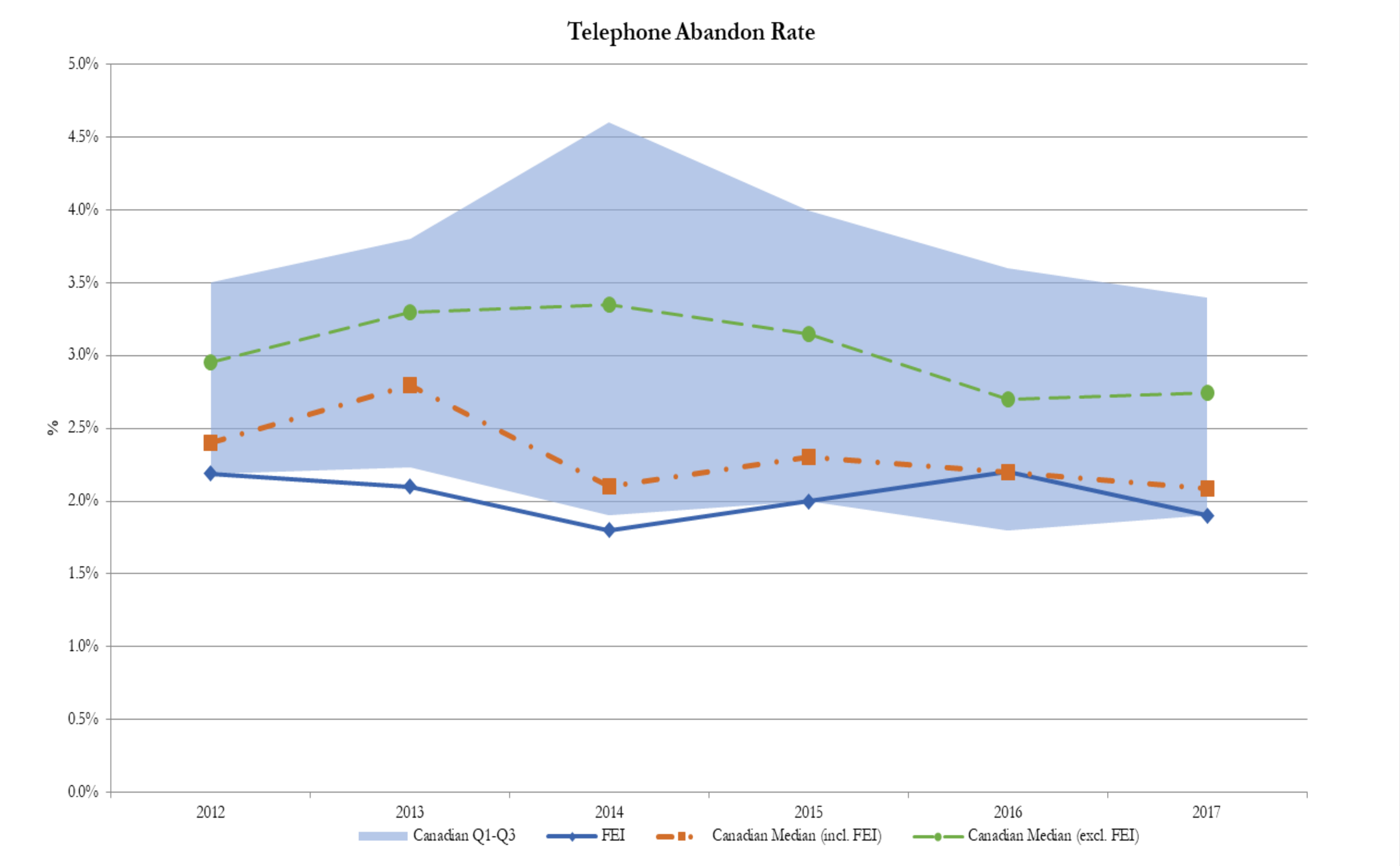
Appendix – FEI
15. Telephone Service Factor – Non-Emergency



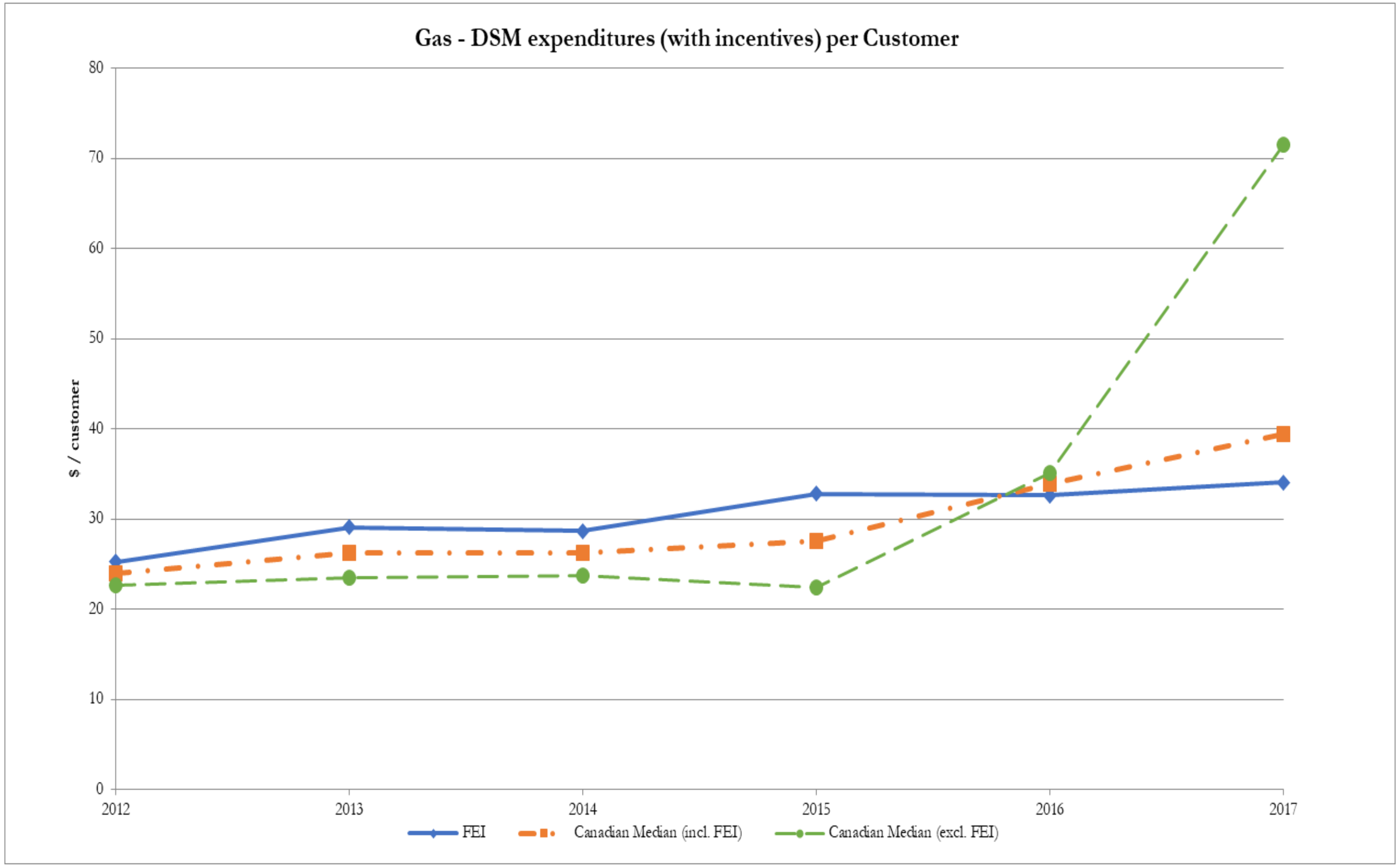
Appendix – FEI
16. First Contact Resolution



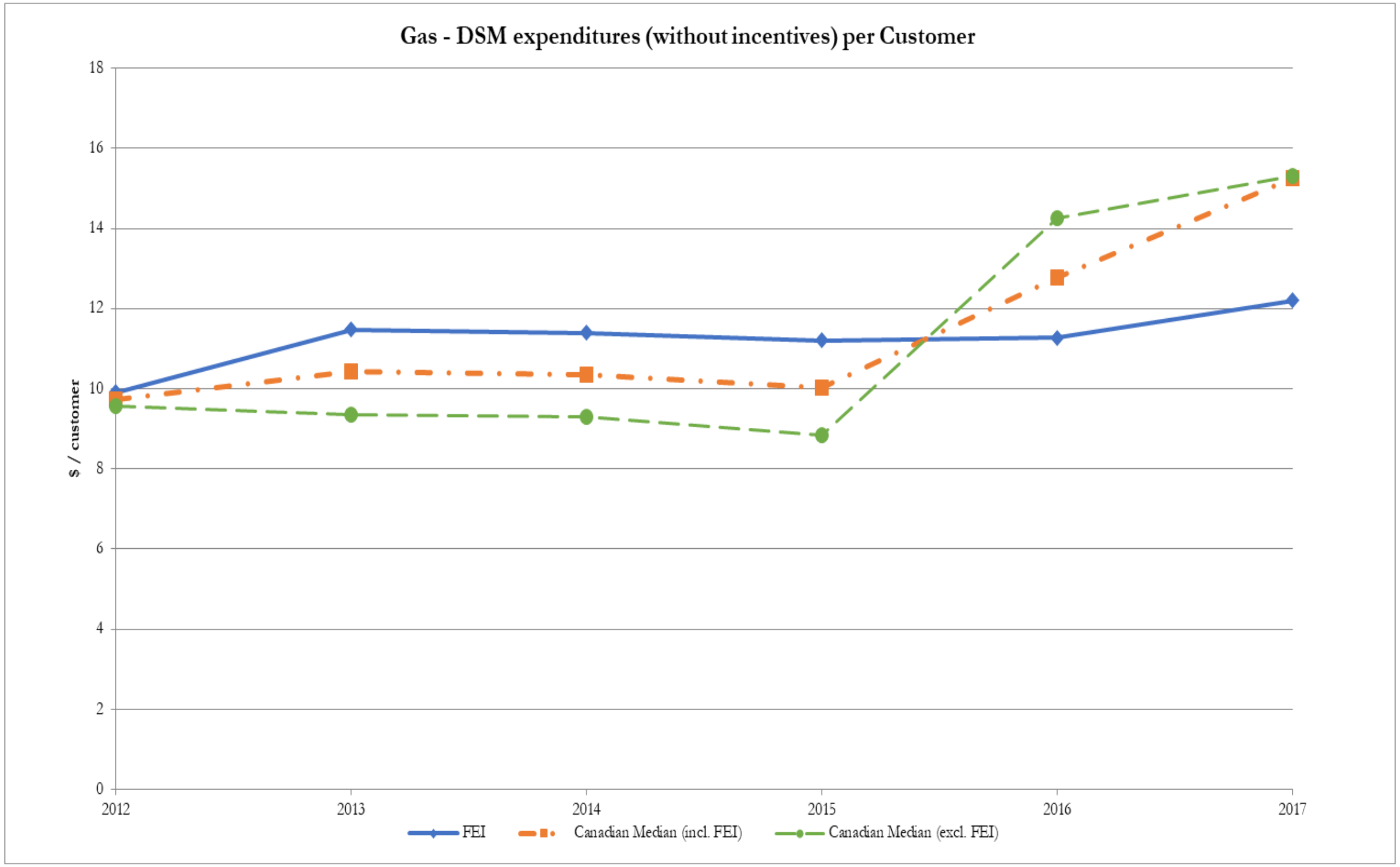
Appendix - FEI
17. Telephone Abandonment Rates



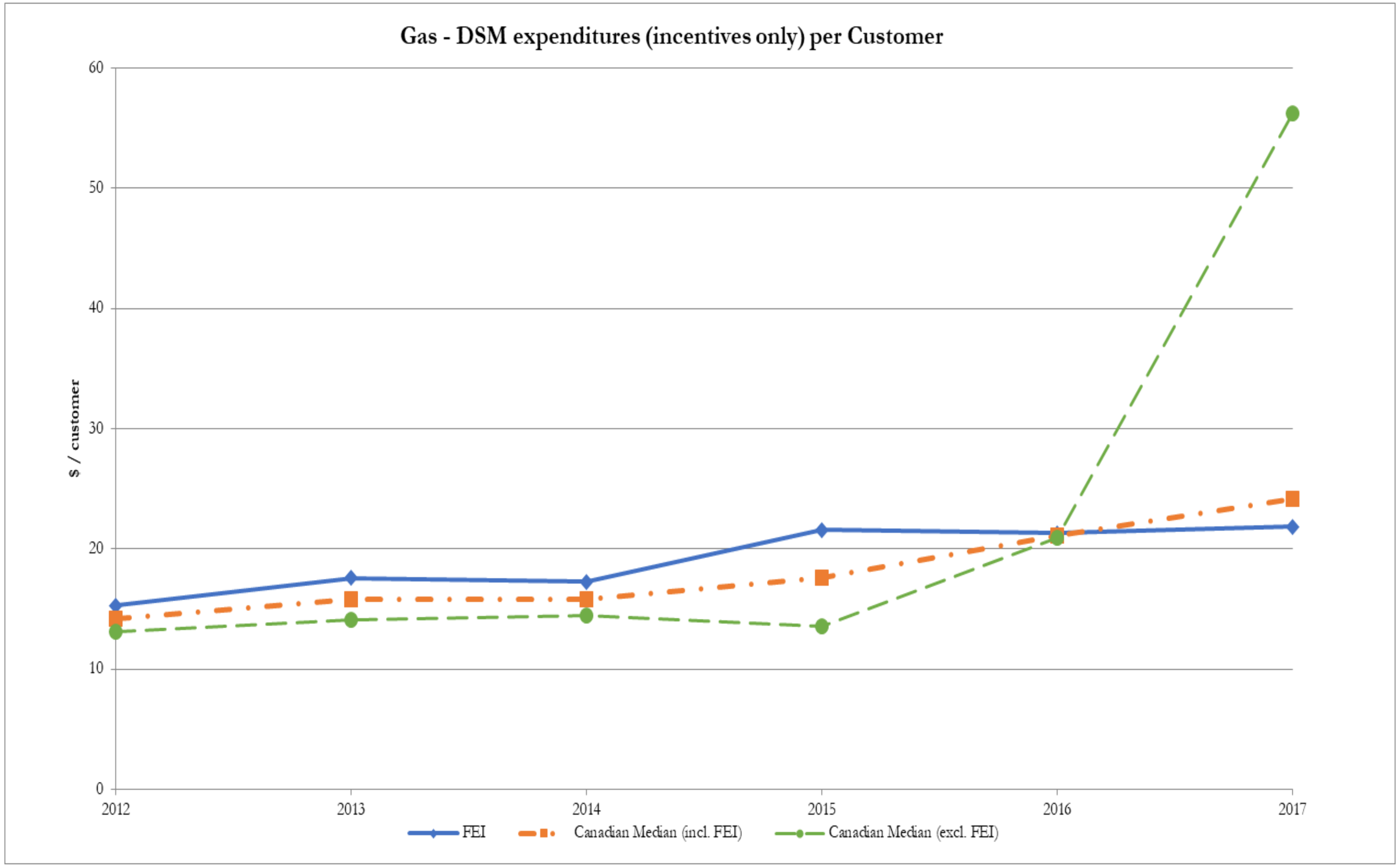
Appendix – FEI
18. DSM Expenditures (with incentives)/Customer



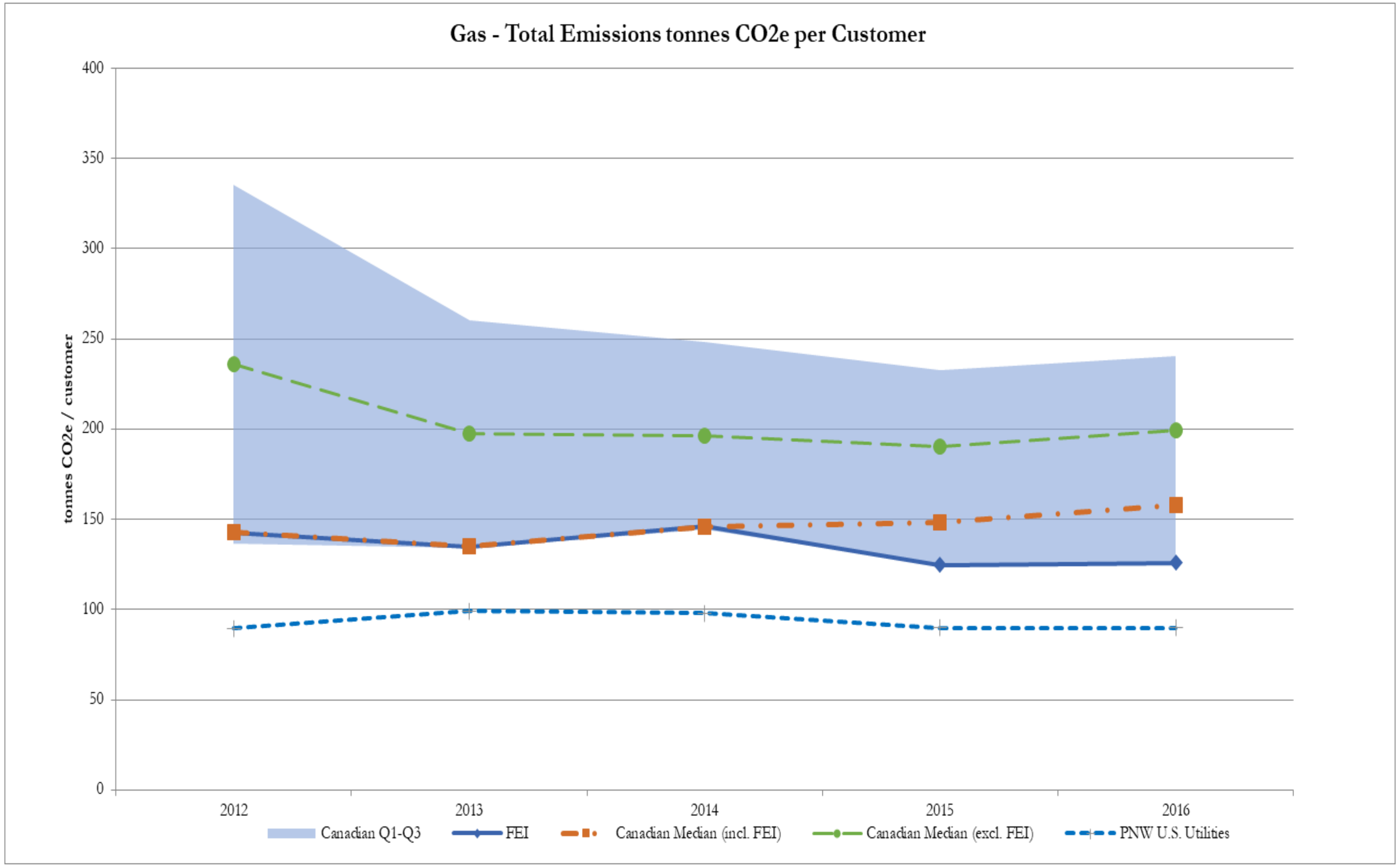
Appendix – FEI
19. DSM Expenditures (without incentives)/Customer



Appendix – FEI
20. DSM Expenditures (incentives only)/Customer



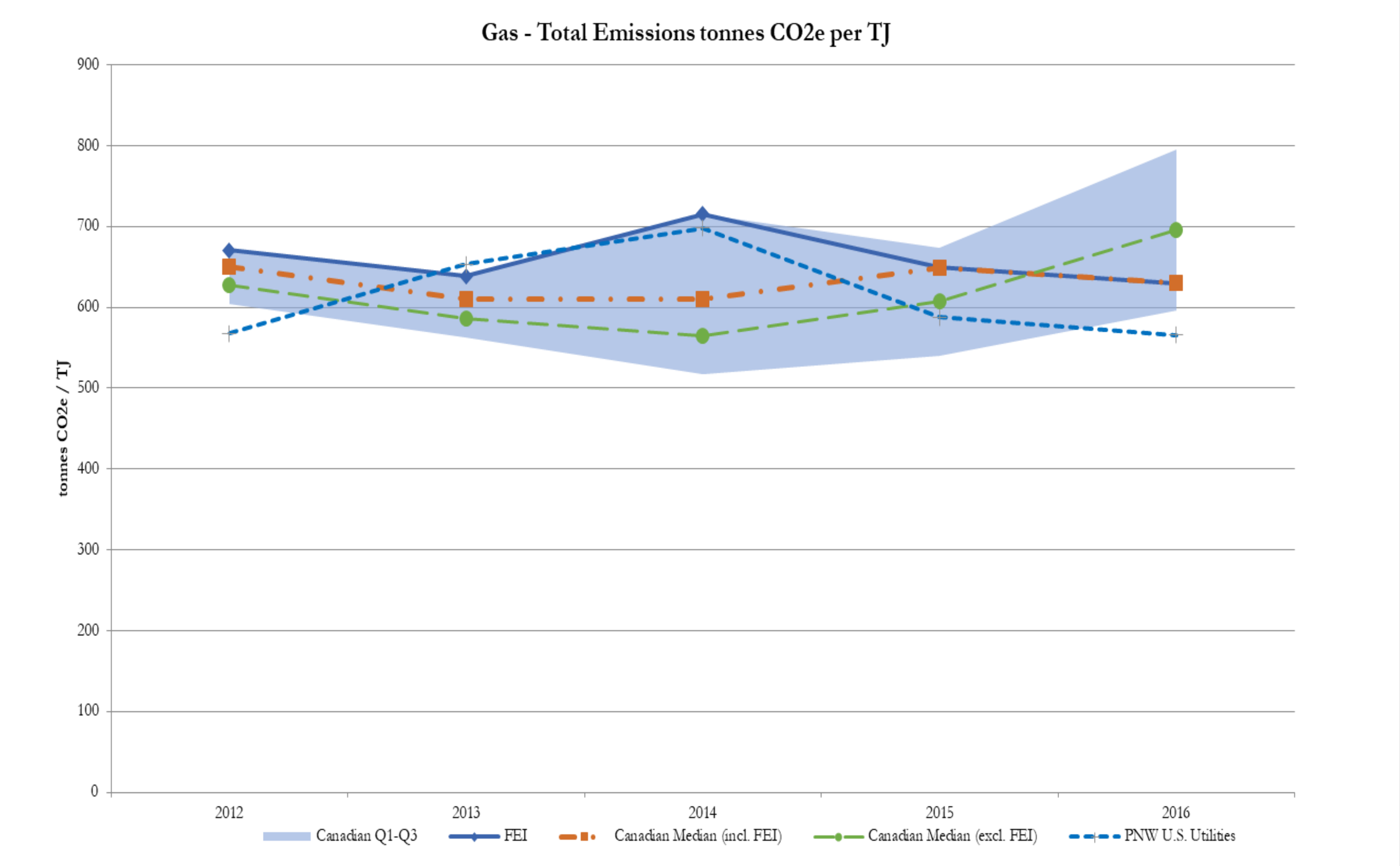
Appendix – FEI
21. GHG Emissions/Customer



CAGRs

- FEI (3.10%)
- Canadian Median (incl. FEI) 2.57%
- Canadian Median (excl. FEI) (4.16%)

Appendix – FEI
22. GHG Emissions/TJ



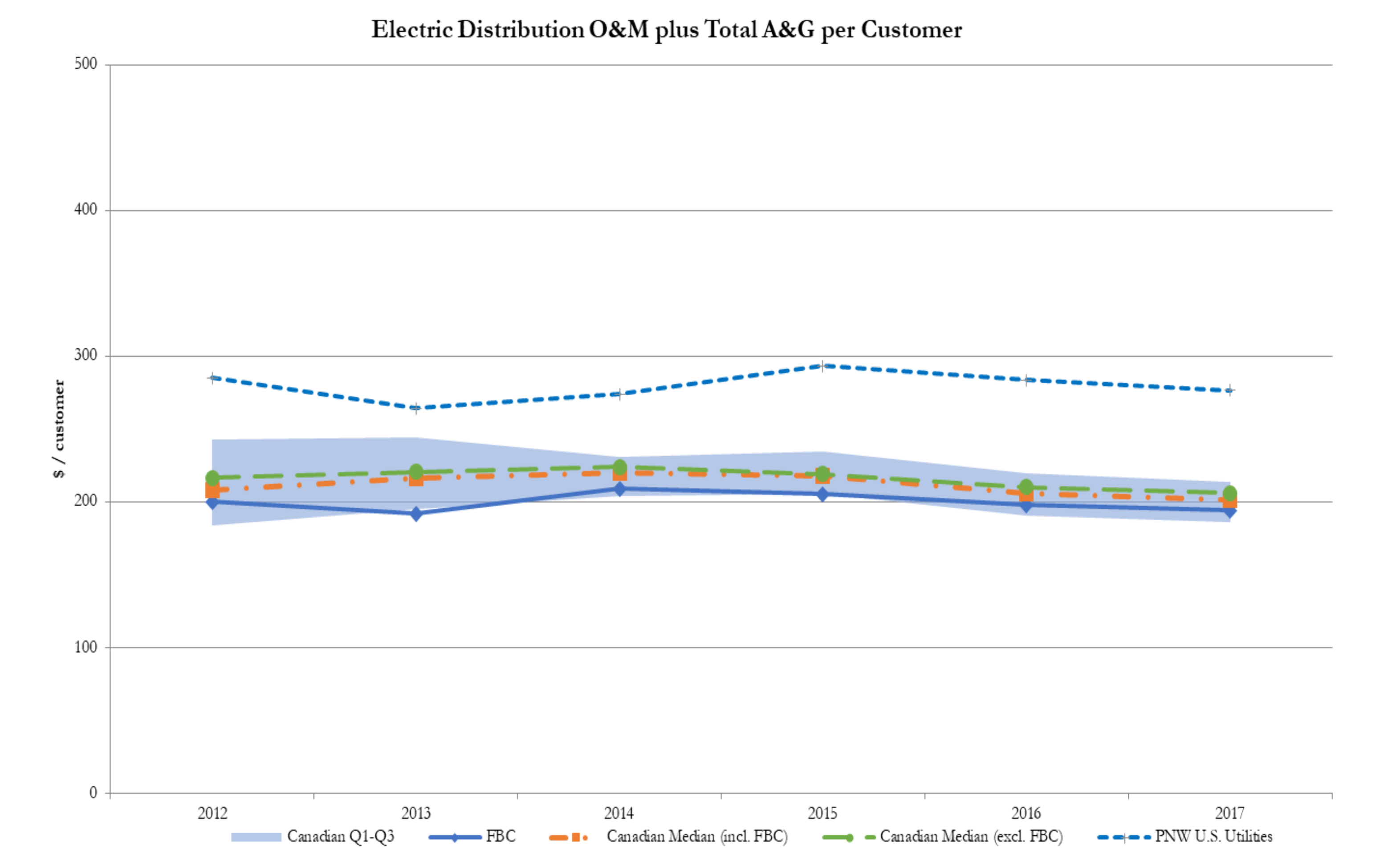
CAGRs

- FEI (1.54%)
- Canadian Median (incl. FEI) (0.78%)
- Canadian Median (excl. FEI) 2.60%

Appendix – FBC Charts

1. Distribution O&M plus Total A&G/Customer
2. Distribution O&M plus Total A&G/MWh
3. Distribution O&M plus Total A&G/Employee
4. Net Distribution Plant/Customer
5. Net Distribution Plant/Employee
6. Total A&G/Customer
7. Total A&G/MWh
8. Electricity Delivered per Employee
9. Employees per Thousand Customers
10. Customer Care Expense/Customer
11. Customer Care Expense/MWh
12. Interest Expense/Customer
13. Emergency Response Time
14. SAIDI
15. Canadian Electric Association Industry Average - SAIDI
16. SAIFI
17. Canadian Electric Association Industry Average - SAIFI
18. Generator Forced Outage Rate
19. Canadian Electric Association Industry Average – GFOR
20. Telephone Service Factor – Non-Emergency
21. First Contact Resolution
22. Telephone Abandonment Rates
23. DSM Expenditures (with incentives)/Customer
24. DSM Expenditures (without incentives)/Customer
25. DSM Expenditures (incentives only)/Customer

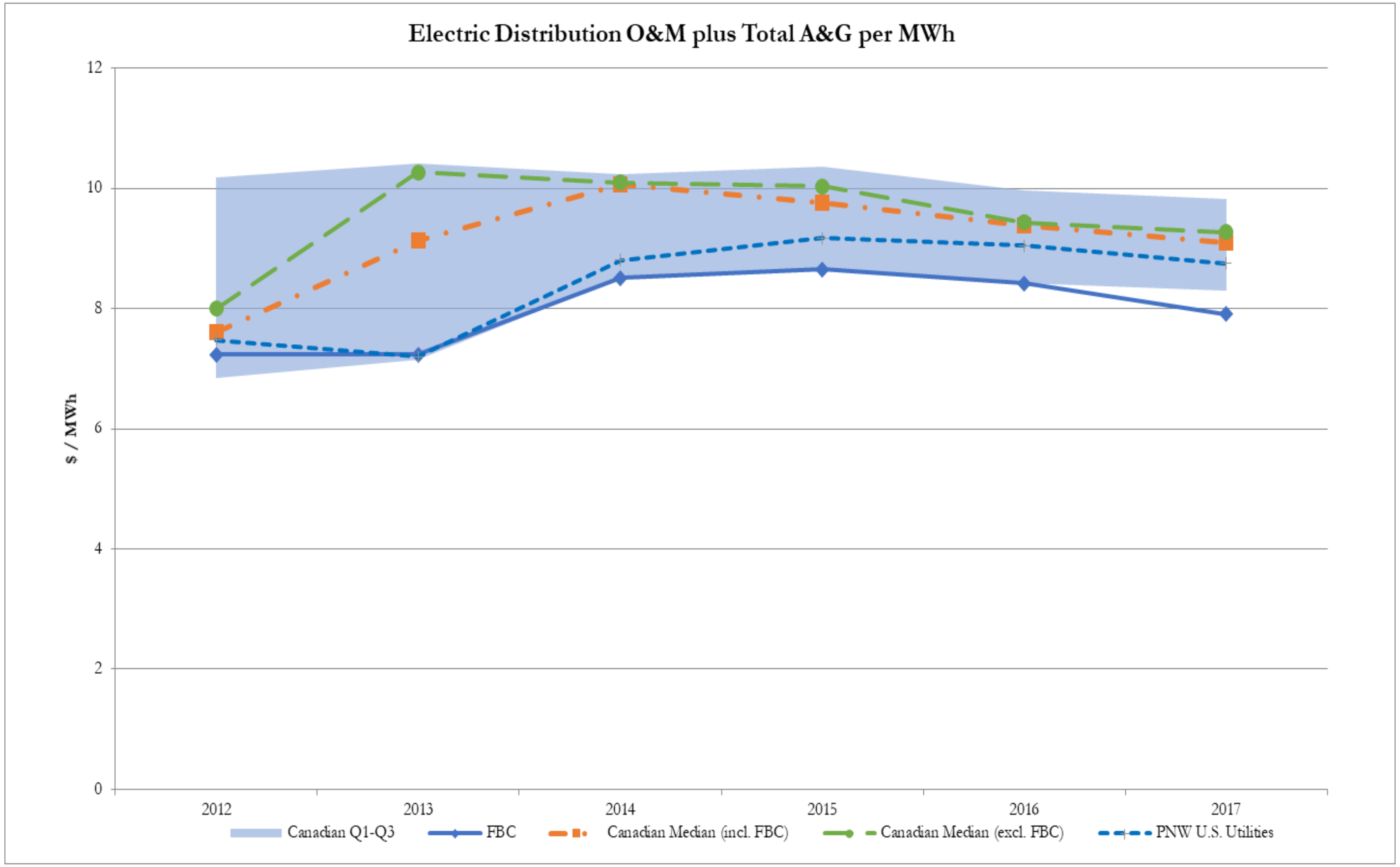
Appendix – FBC
1. Distribution O&M plus Total A&G/Customer



CAGRs

- FBC (0.62%)
- Canadian Median (incl. FBC) (0.66%)
- Canadian Median (excl. FBC) (0.98%)
- PNW U.S. Utilities (0.60%)

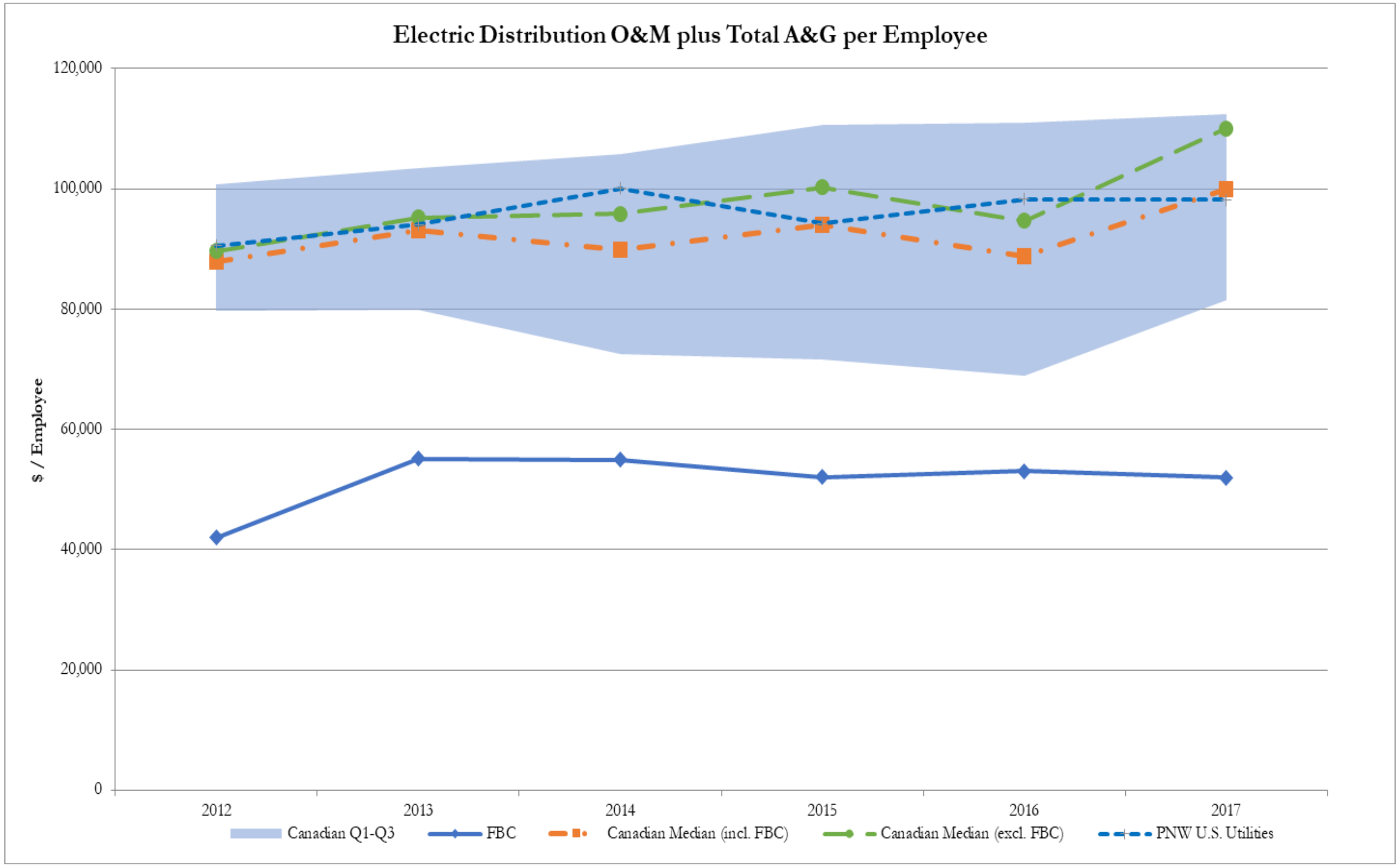
Appendix – FBC
2. Distribution O&M plus Total A&G/MWh



CAGRs

- FBC
  1.80%
- Canadian Median (incl. FBC)
  3.64%
- Canadian Median (excl. FBC)
  3.00%
- PNW U.S. Utilities
  3.19%

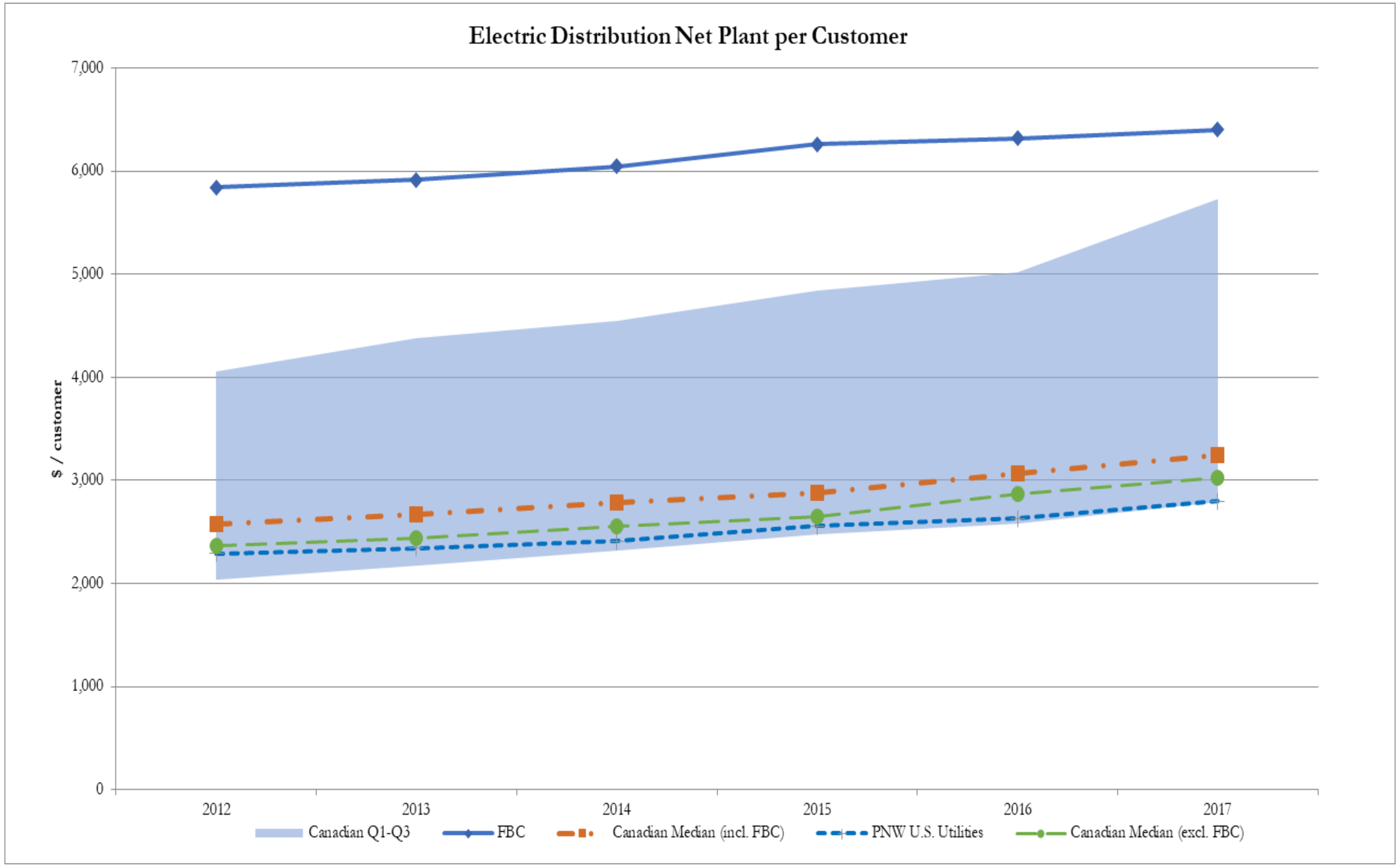
Appendix – FBC
3. Distribution O&M plus Total A&G/Employee



CAGRs

- FBC 4.34%
- Canadian Median (incl. FBC) 2.59%
- Canadian Median (excl. FBC) 4.18%
- PNW U.S. Utilities 1.63%

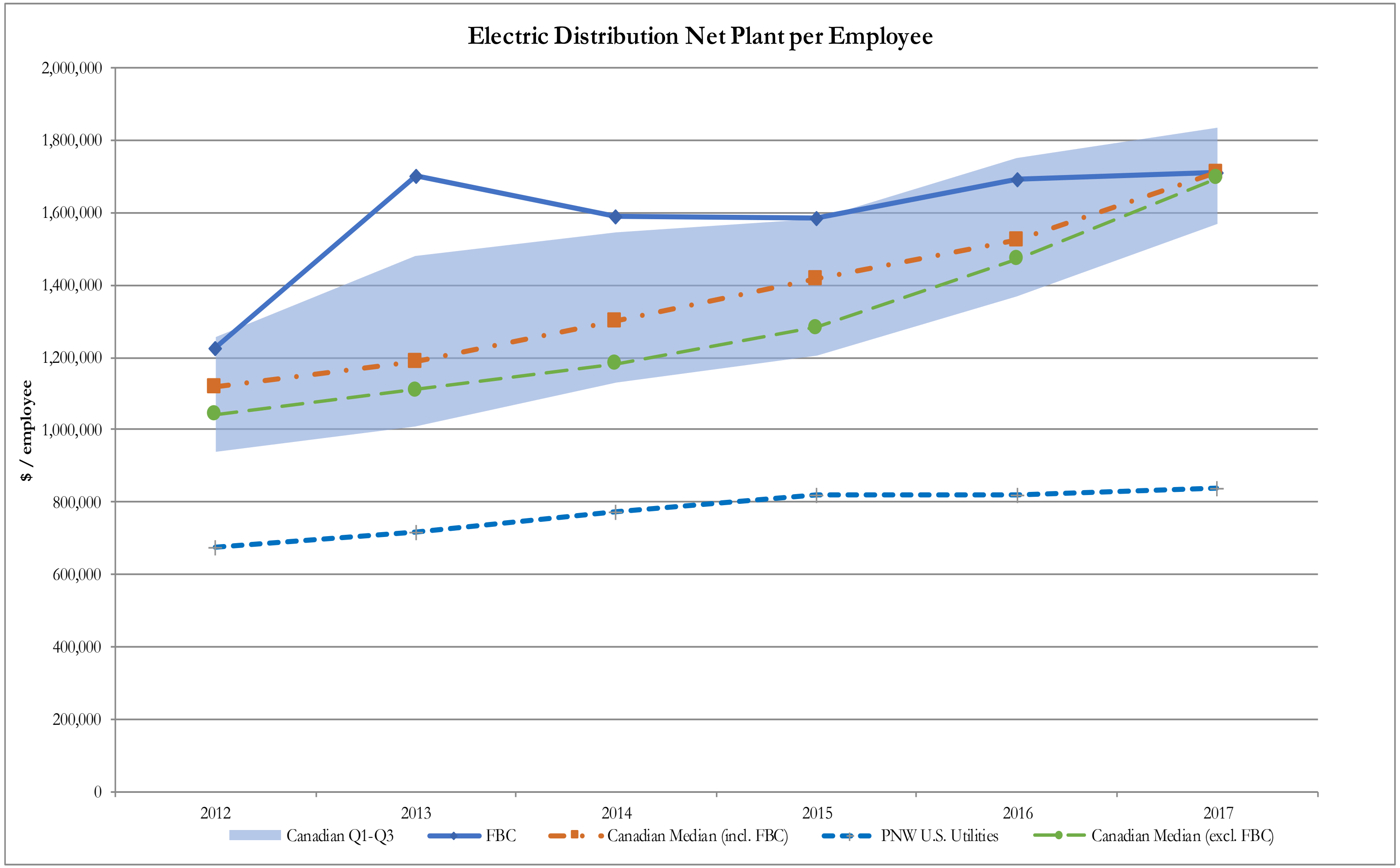
Appendix – FBC
4. Net Distribution Plant/Customer



CAGRs

- FBC 1.85%
- Canadian Median (incl. FBC) 4.73%
- Canadian Median (excl. FBC) 5.07%
- PNW U.S. Utilities 4.08%

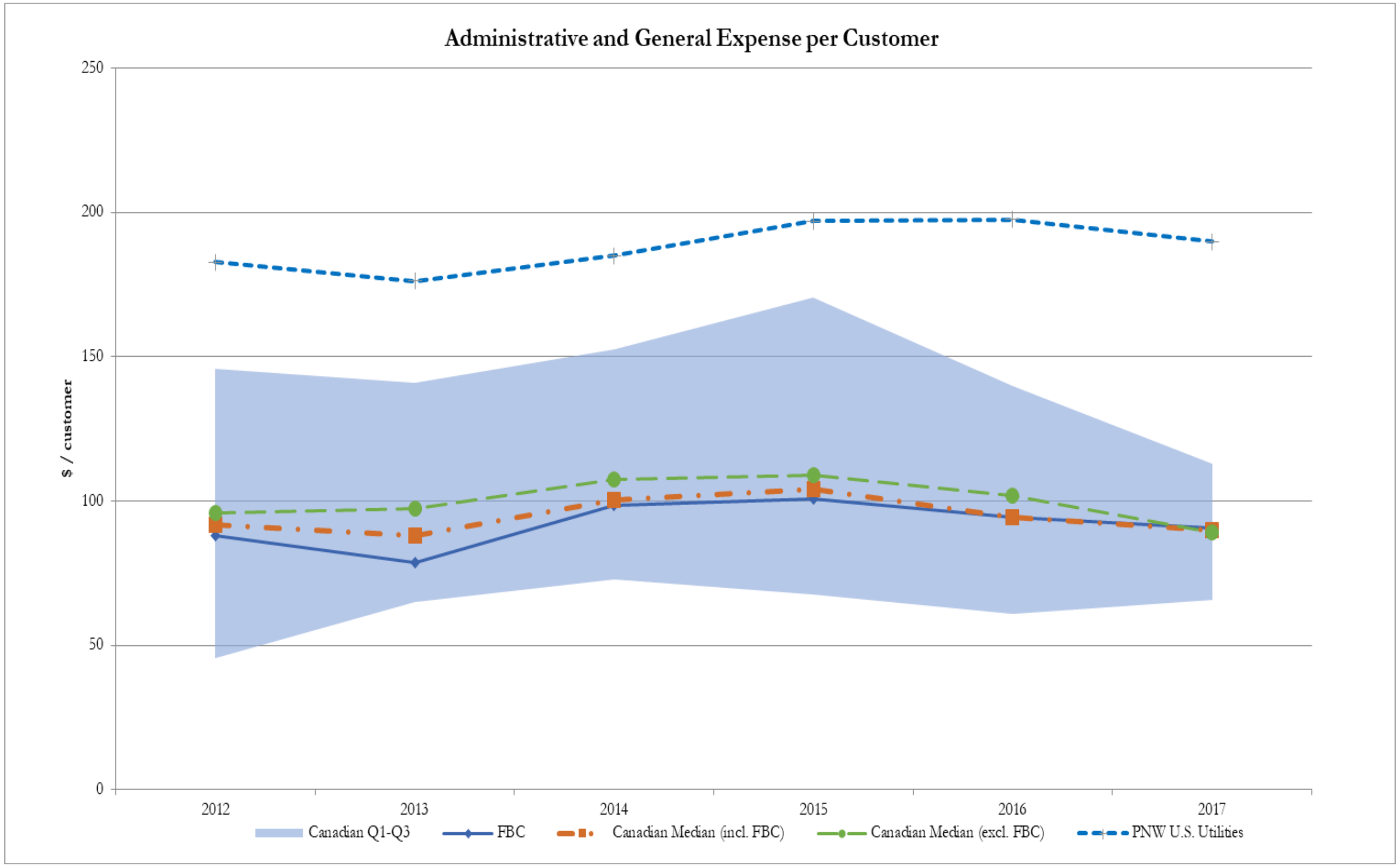
Appendix – FBC
5. Net Distribution Plant/Employee



CAGRs

- FBC
  6.94%
- Canadian Median (incl. FBC)
  8.92%
- Canadian Median (excl. FBC)
  10.20%
- PNW U.S. Utilities
  4.34%

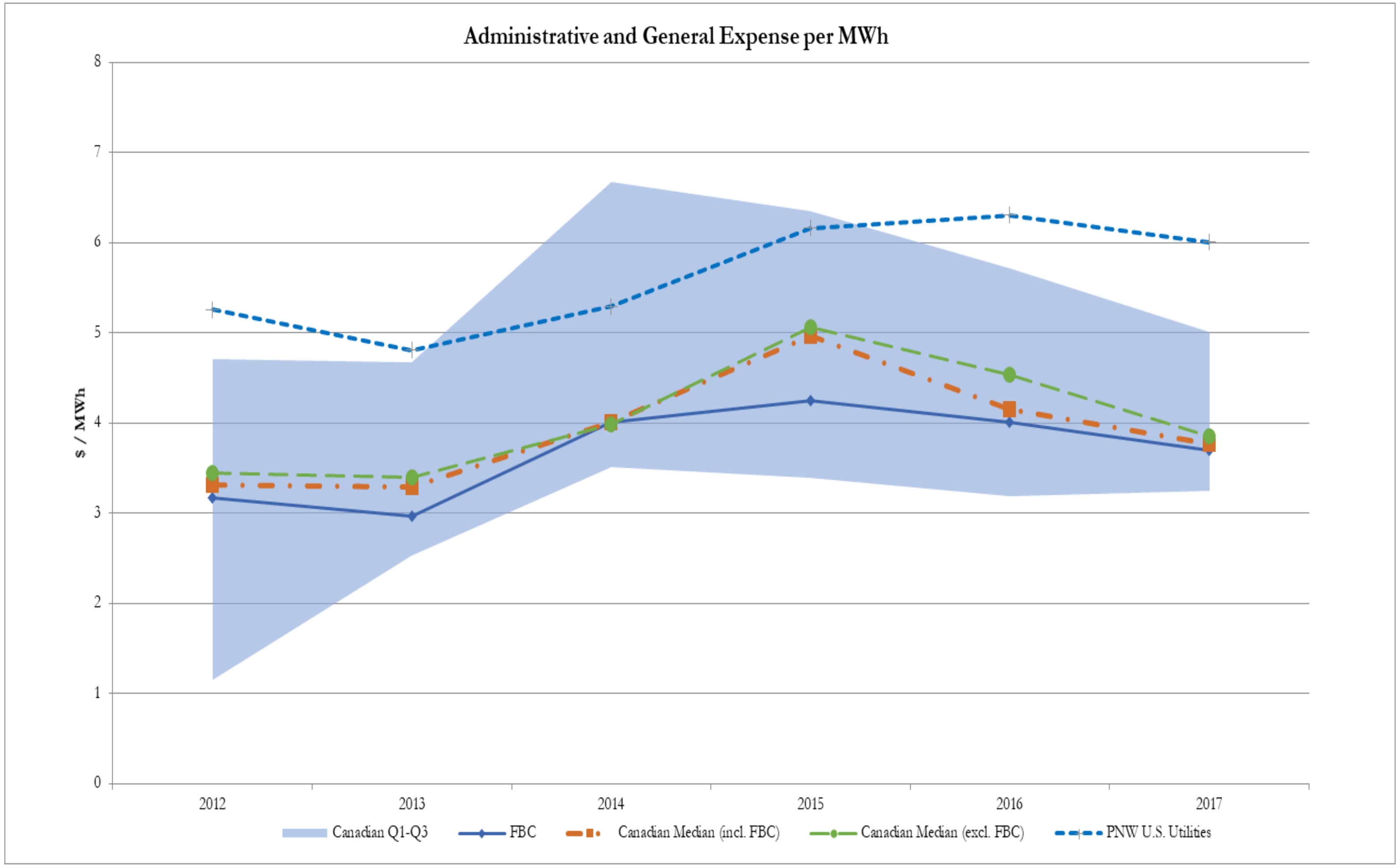
Appendix – FBC
6. Total A&G/Customer



CAGRs

- FBC 0.61%
- Canadian Median (incl. FBC) (0.45%)
- Canadian Median (excl. FBC) (1.46%)
- PNW U.S. Utilities 0.76%

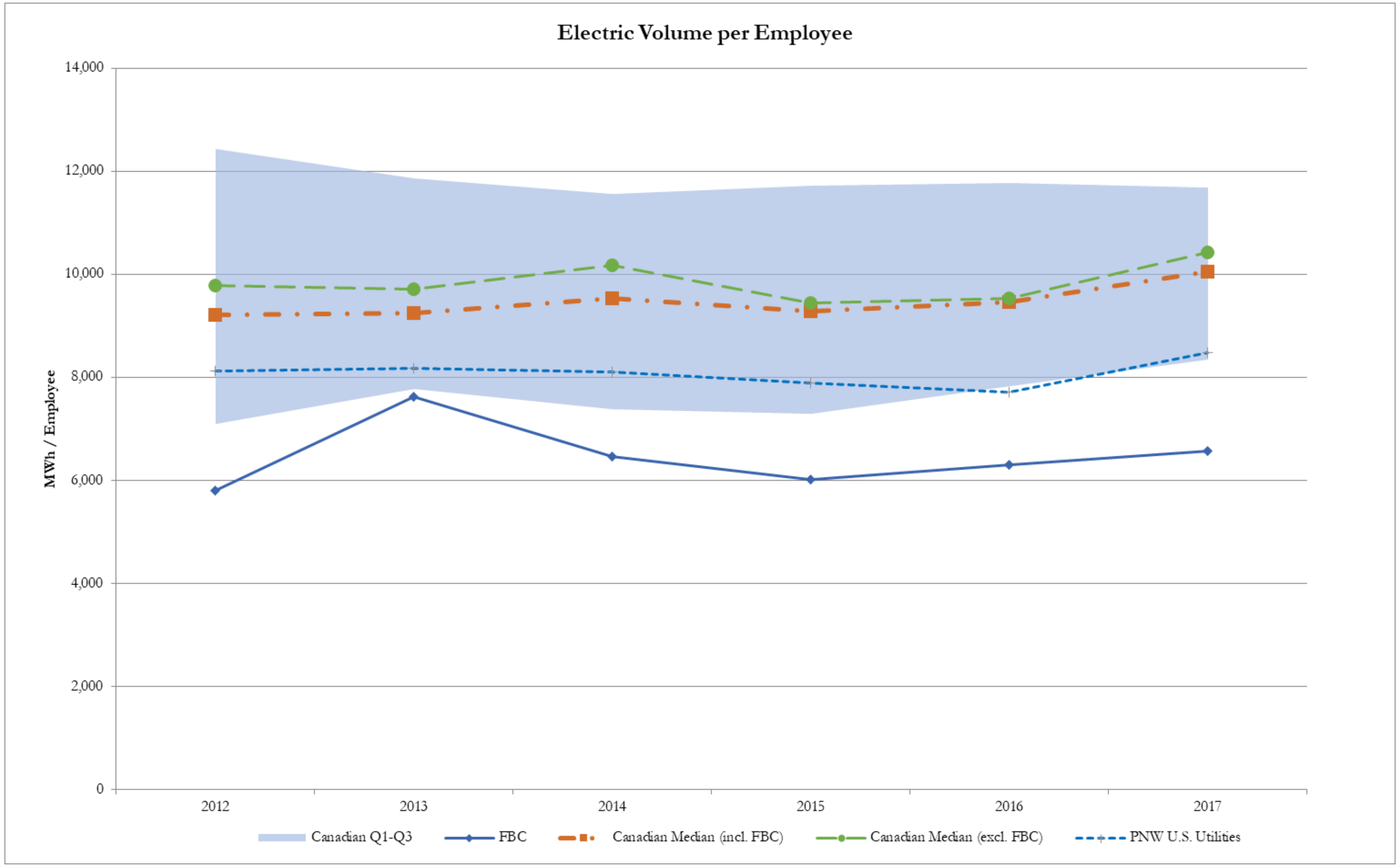
Appendix – FBC
7. Total A&G/MWh



CAGRs

- FBC
  3.06%
- Canadian Median (incl. FBC)
  2.64%
- Canadian Median (excl. FBC)
  2.24%
- PNW U.S. Utilities
  2.70%

Appendix – FBC
8. Electricity Delivered per Employee



CAGRs

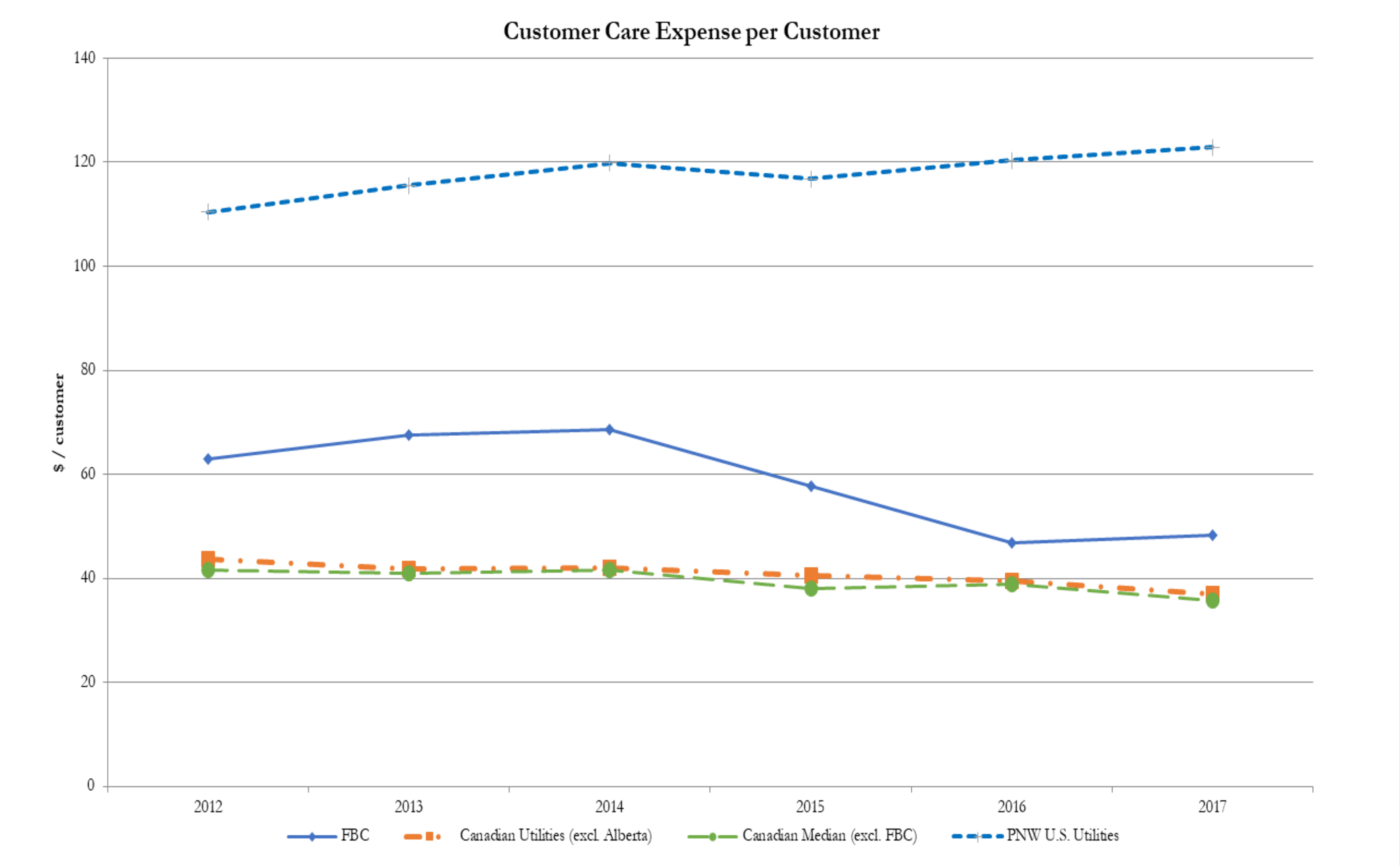
- FBC 2.50%
- Canadian Median (incl. FBC) 1.77%
- Canadian Median (excl. FBC) 1.29%
- PNW U.S. Utilities 0.89%

Appendix – FBC
9. Employees per Thousand Customers

CAGRs

- FBC (4.76%)
- Canadian Median (incl. FBC) (1.44%)
- Canadian Median (excl. FBC) (2.63%)
- PNW U.S. Utilities (1.31%)

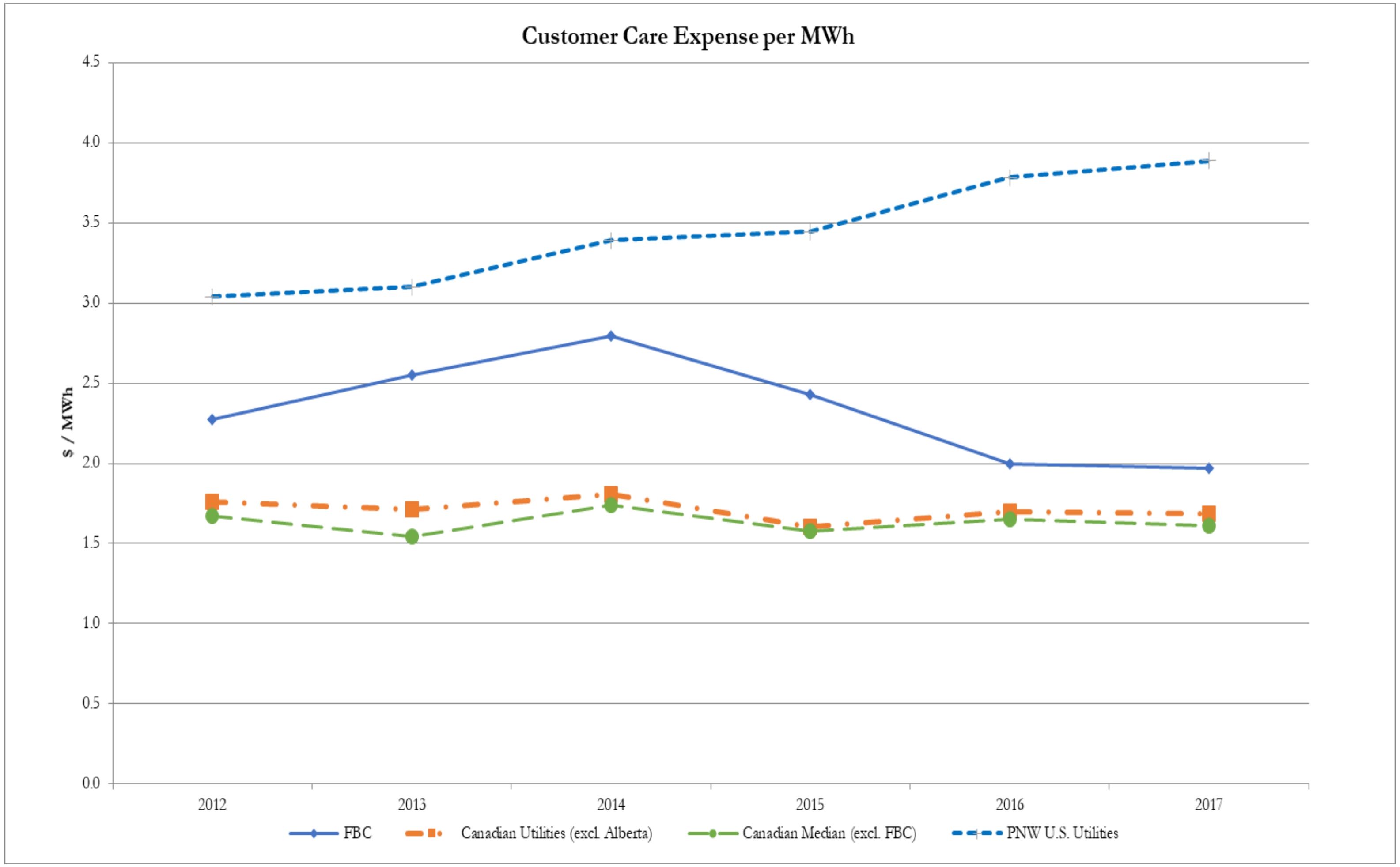
Appendix – FBC
10. Customer Care Expense/Customer



CAGRs

- FBC (5.18%)
- Canadian Median (incl. FBC) (3.27%)
- Canadian Median (excl. FBC) (2.97%)
- PNW U.S. Utilities (2.17%)

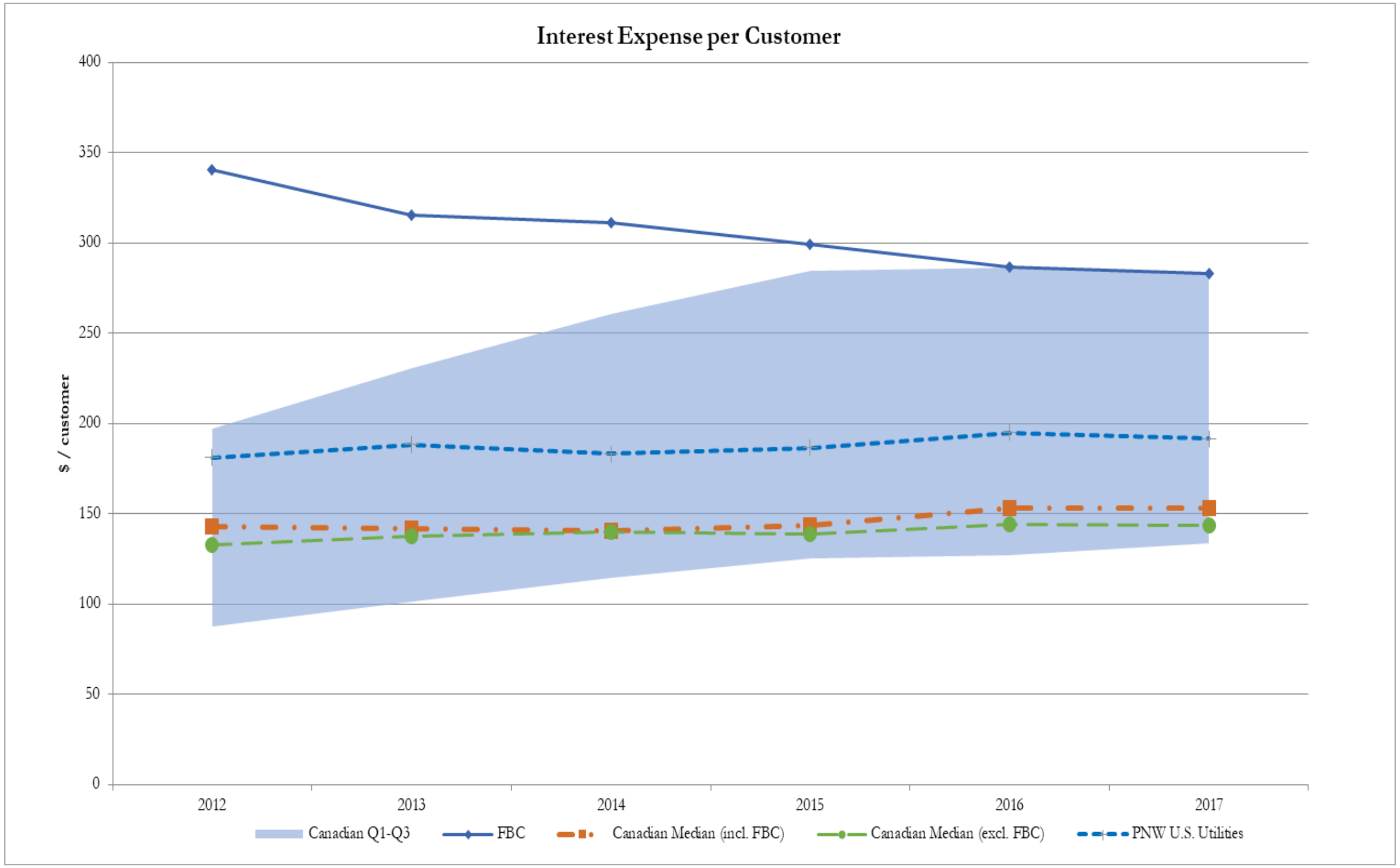
Appendix – FBC
11. Customer Care Expense/MWh



CAGRs

- FBC (2.87%)
- Canadian Median (incl. FBC) (0.87%)
- Canadian Median (excl. FBC) (0.79%)
- PNW U.S. Utilities 5.04%

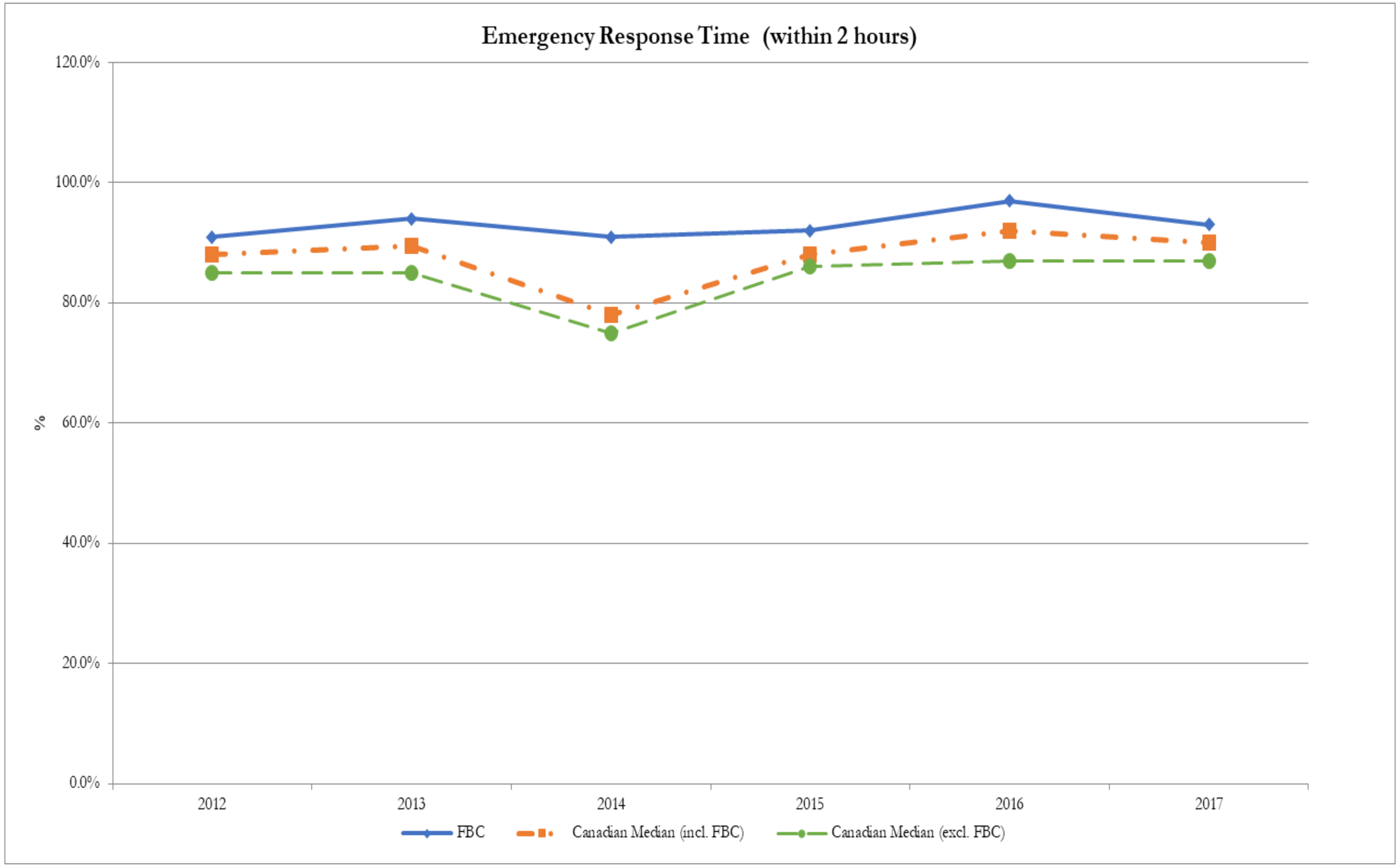
Appendix – FBC
12. Interest Expense/Customer



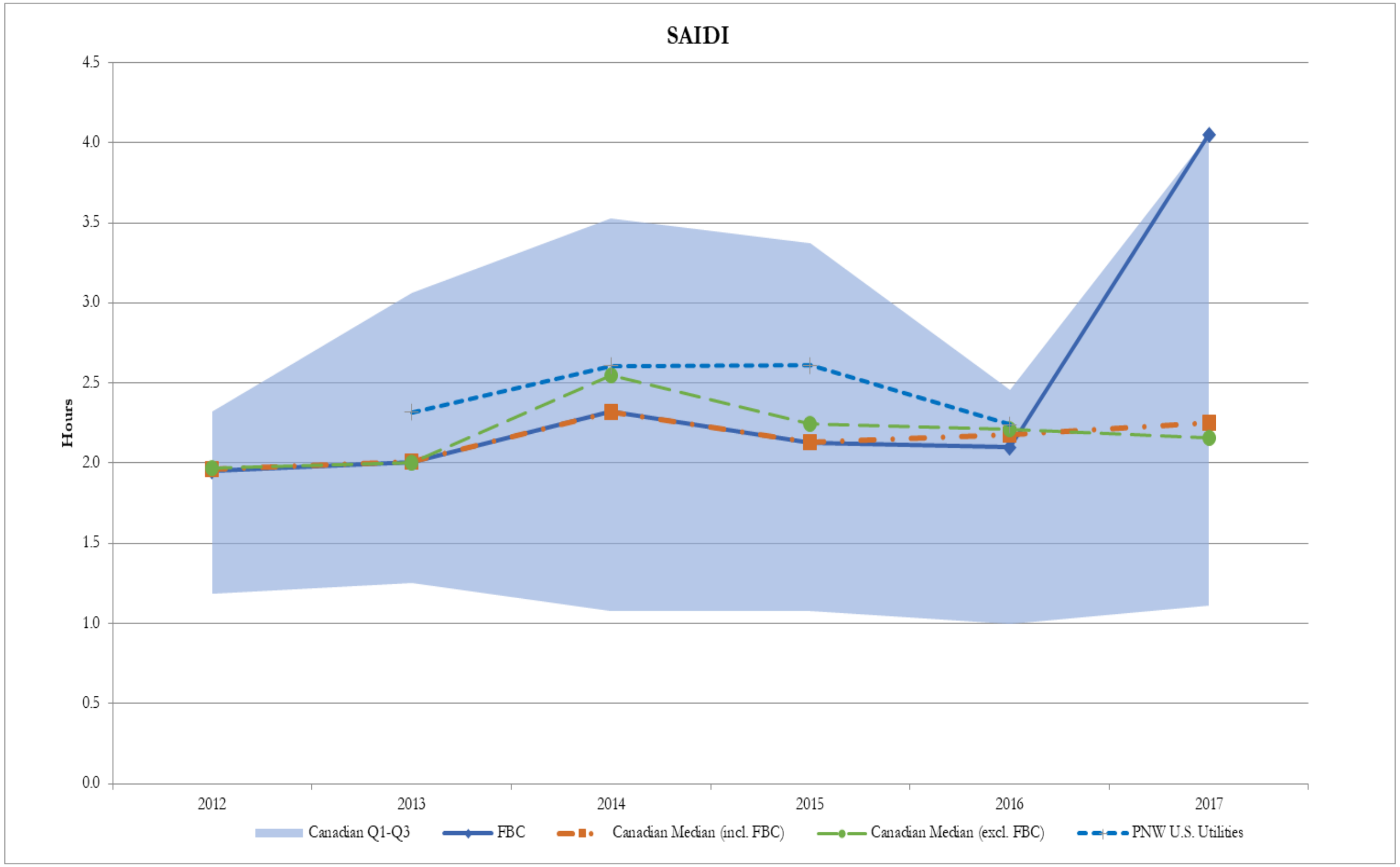
CAGRs

- FBC (3.63%)
- Canadian Median (incl. FBC) 1.38%
- Canadian Median (excl. FBC) 1.63%
- PNW U.S. Utilities 1.14%

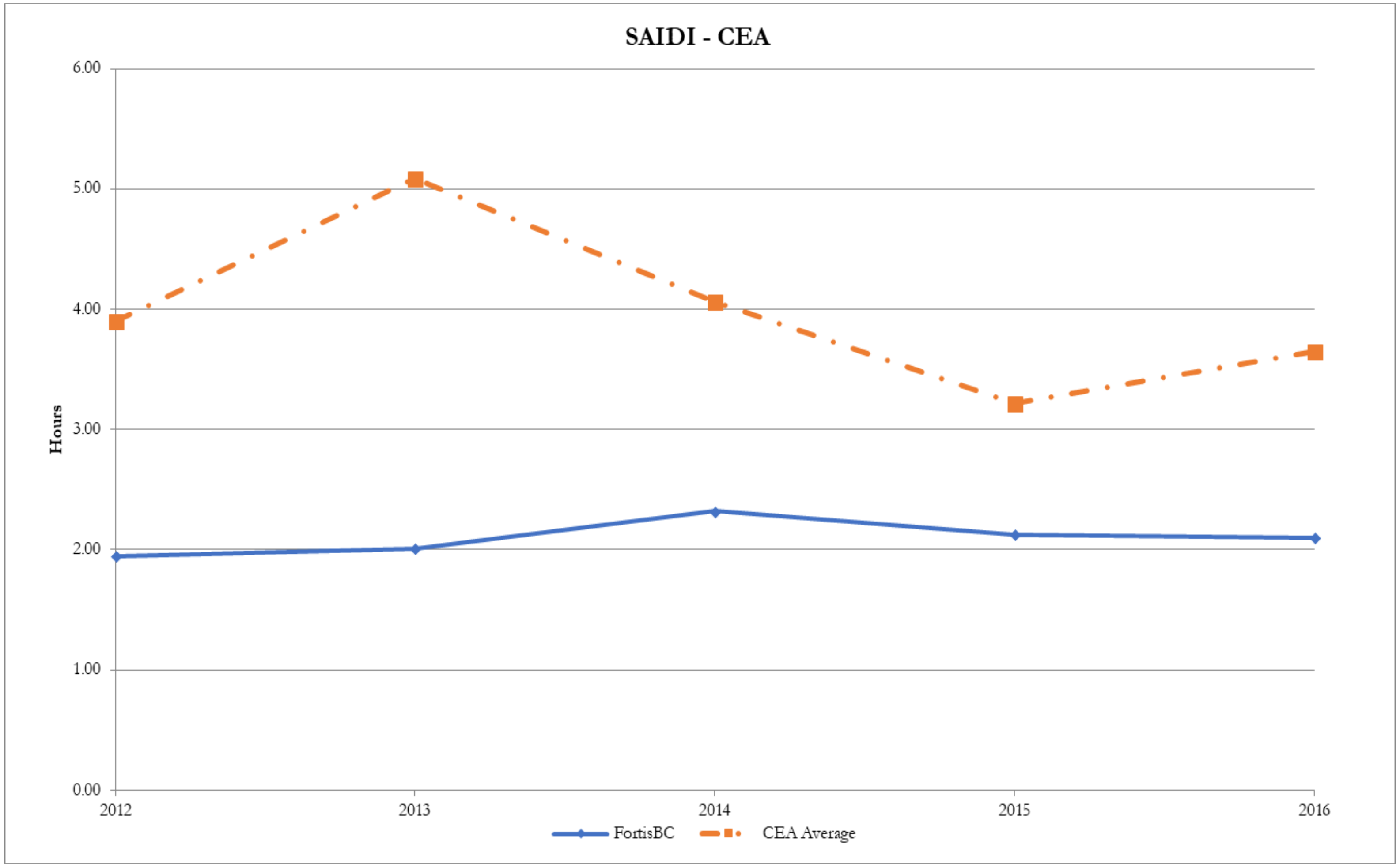
Appendix – FBC
13. Emergency Response Time



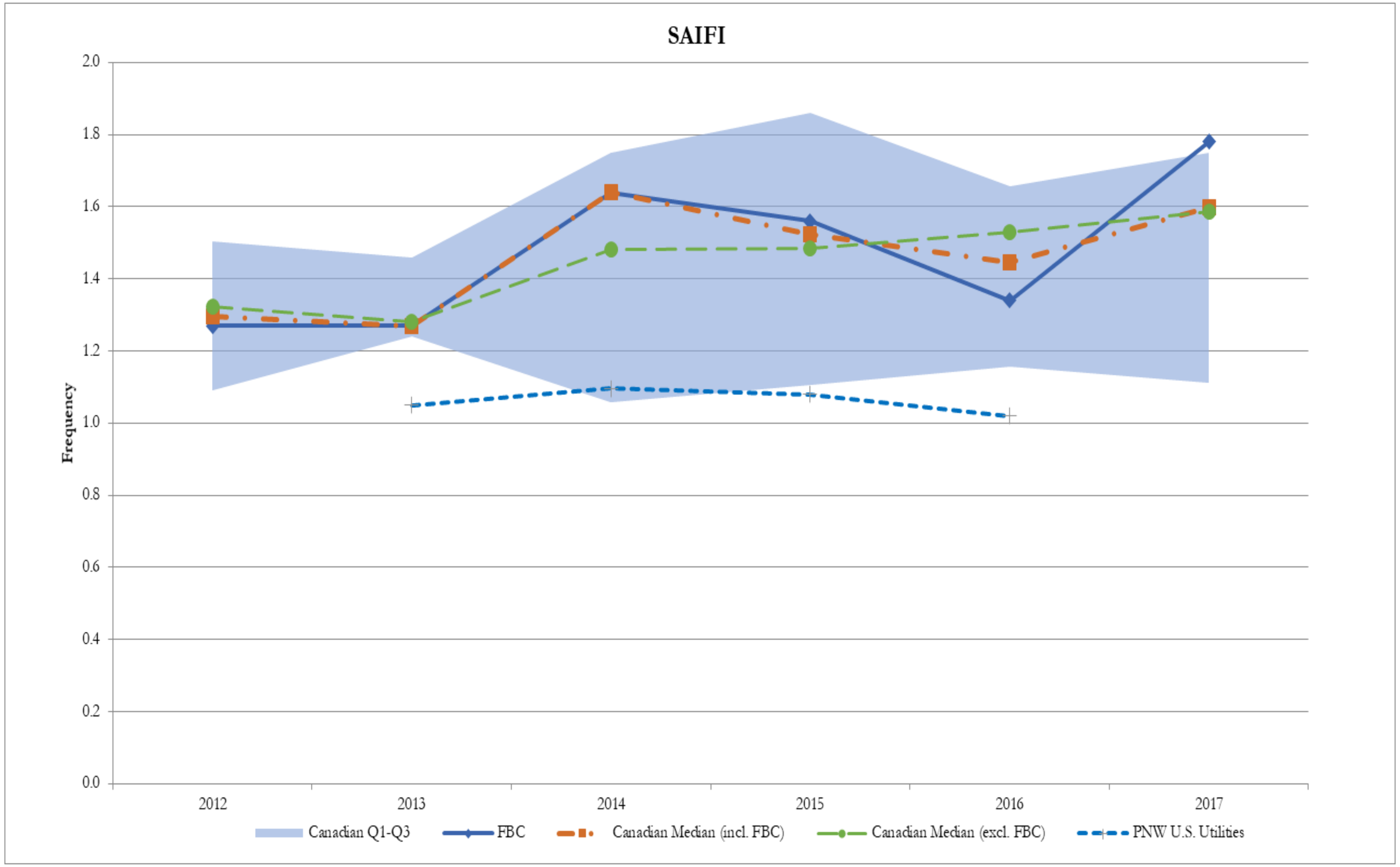
Appendix – FBC
14. SAIDI



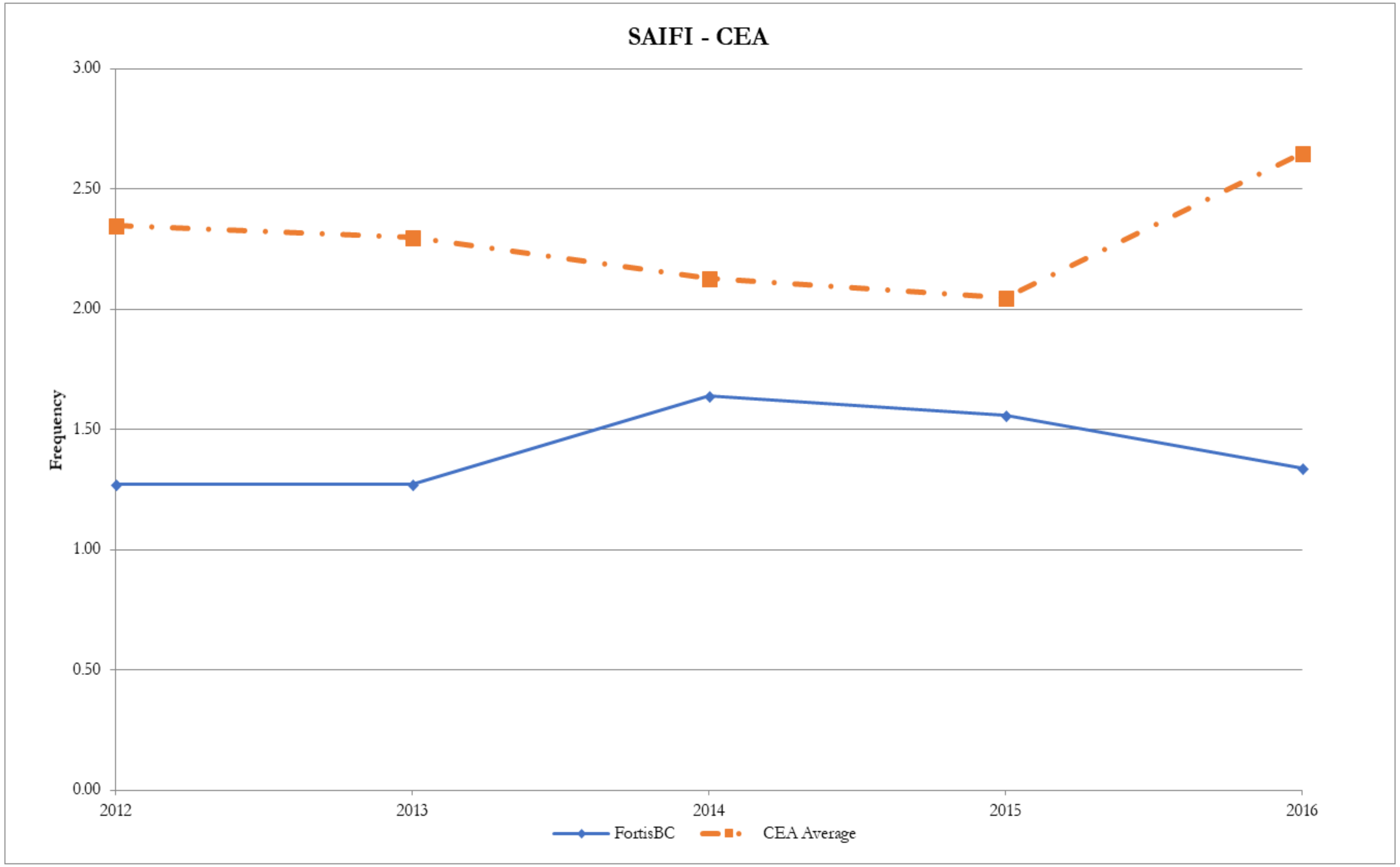
Appendix – FBC
15. Canadian Electric Association Industry Average - SAIDI



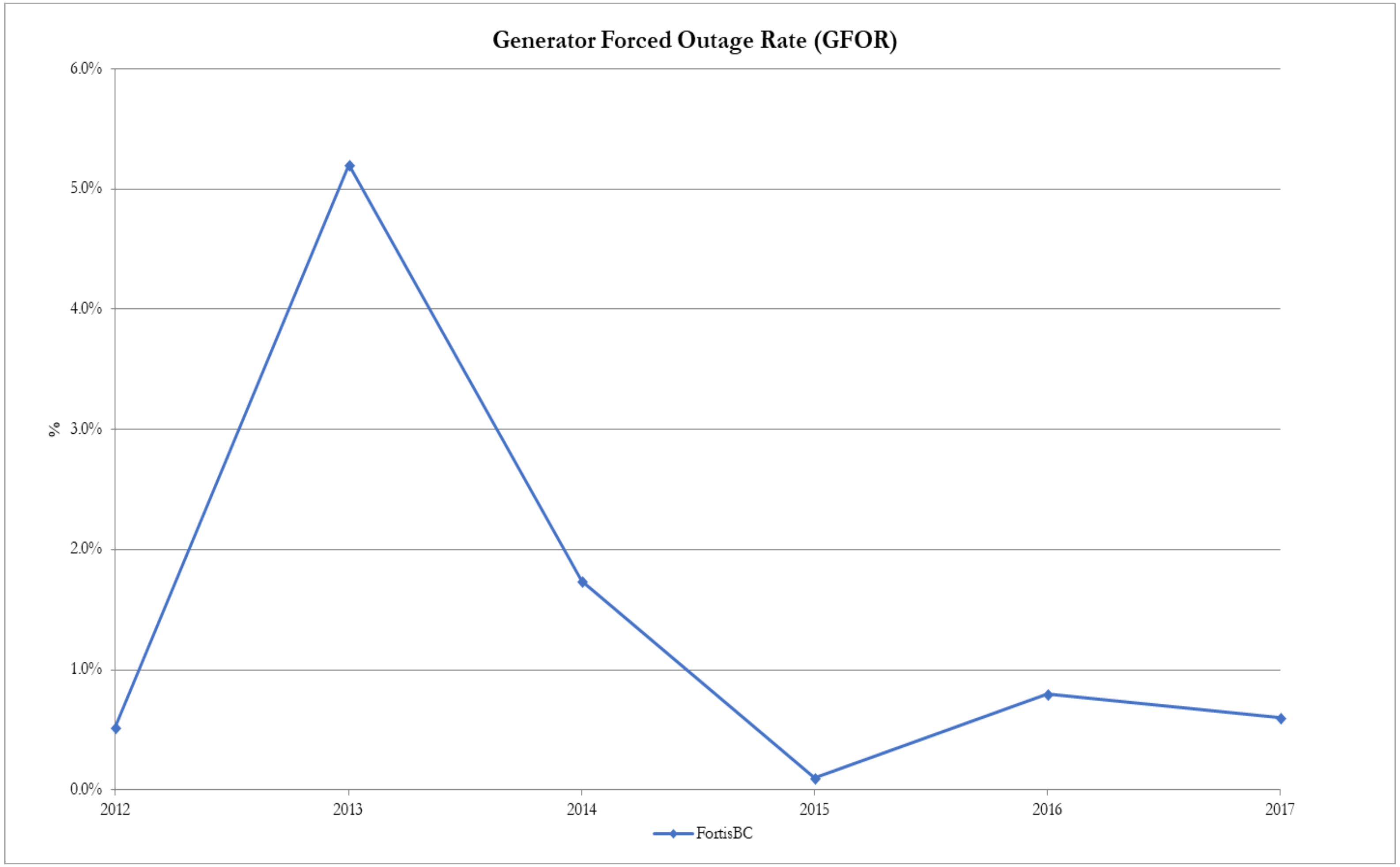
Appendix – FBC
16. SAIFI



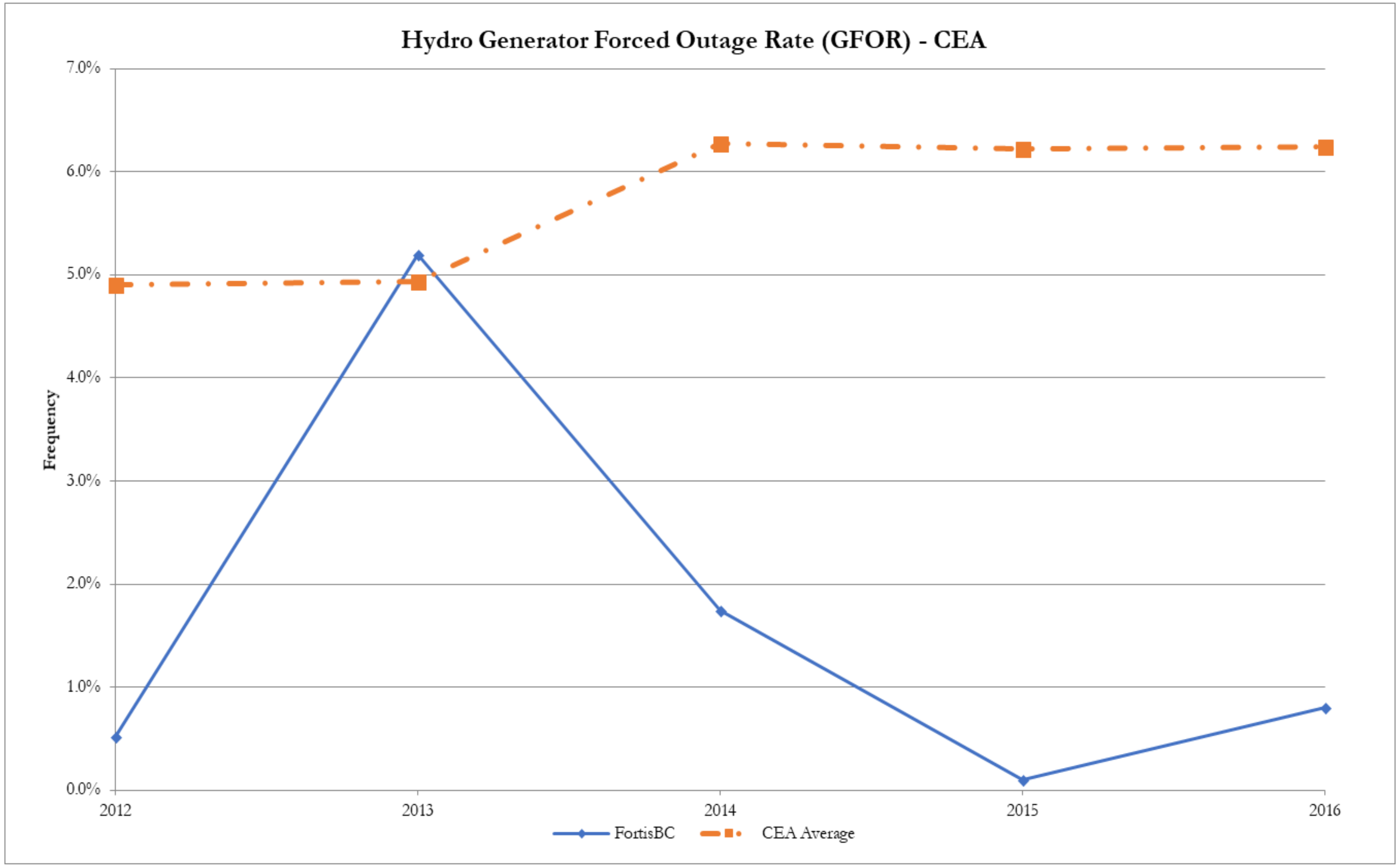
Appendix – FBC
17. Canadian Electric Association Industry Average - SAIFI



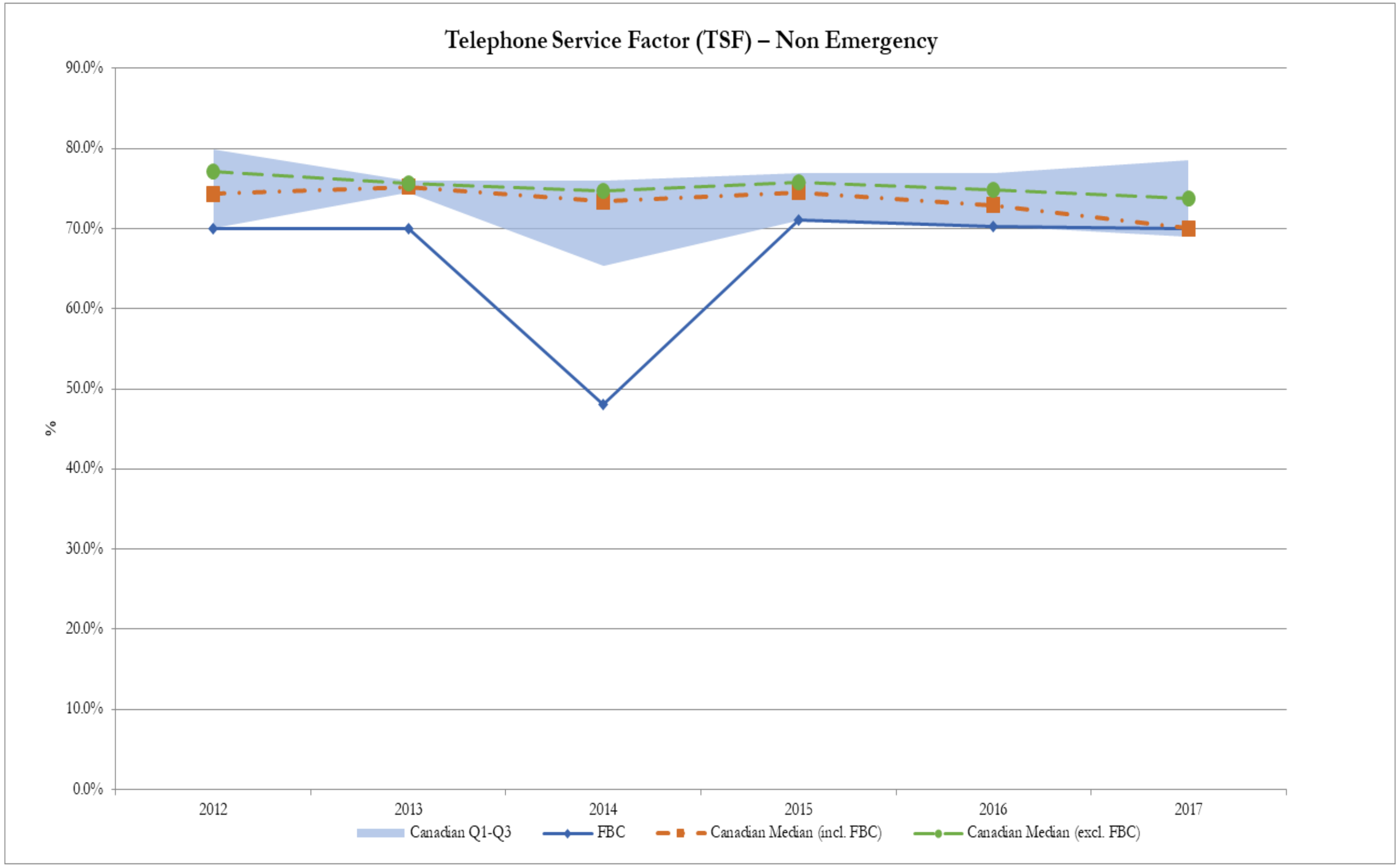
Appendix – FBC
18. Generator Forced Outage Rate



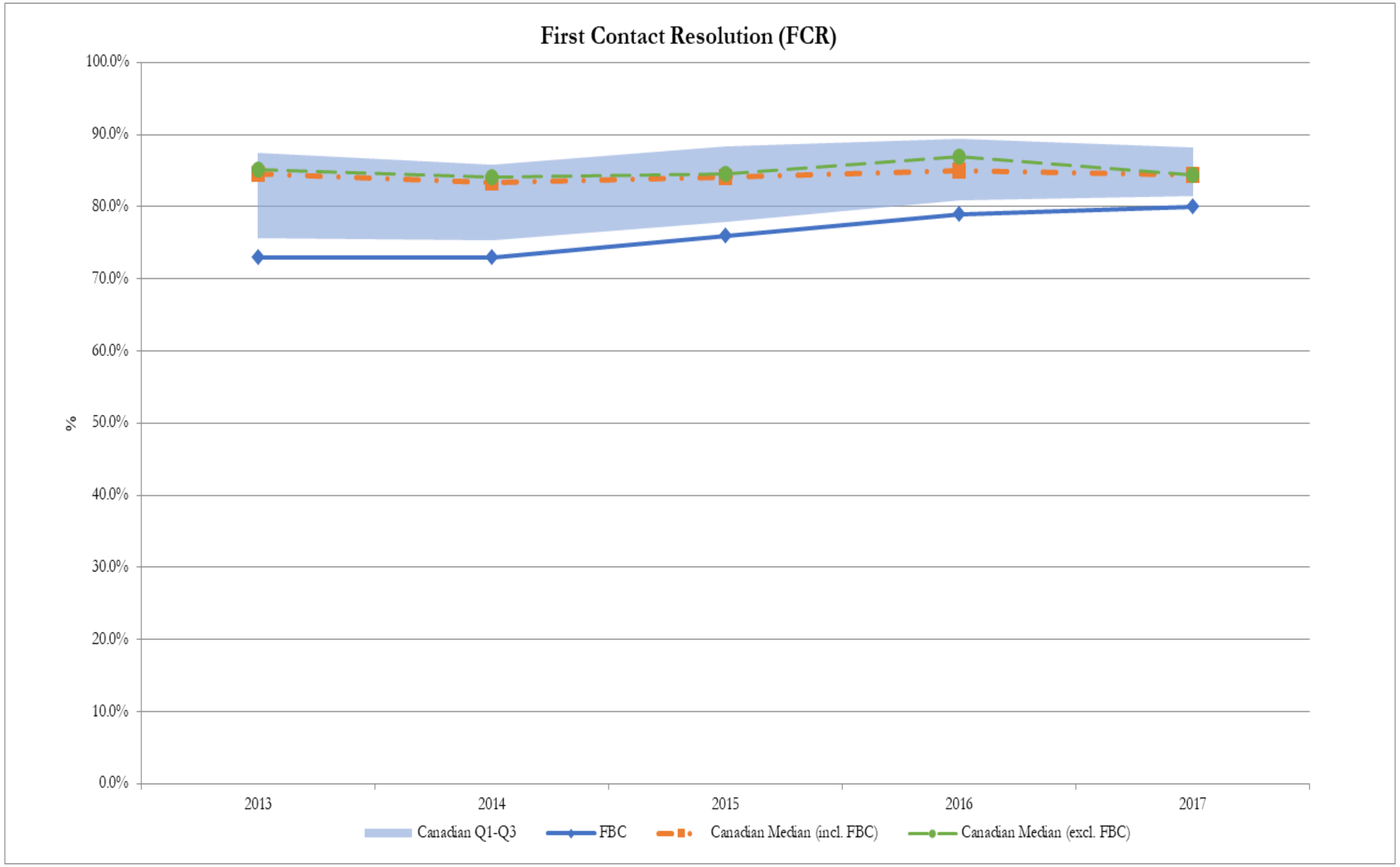
Appendix – FBC
19. Canadian Electric Association Industry Average - GFOR



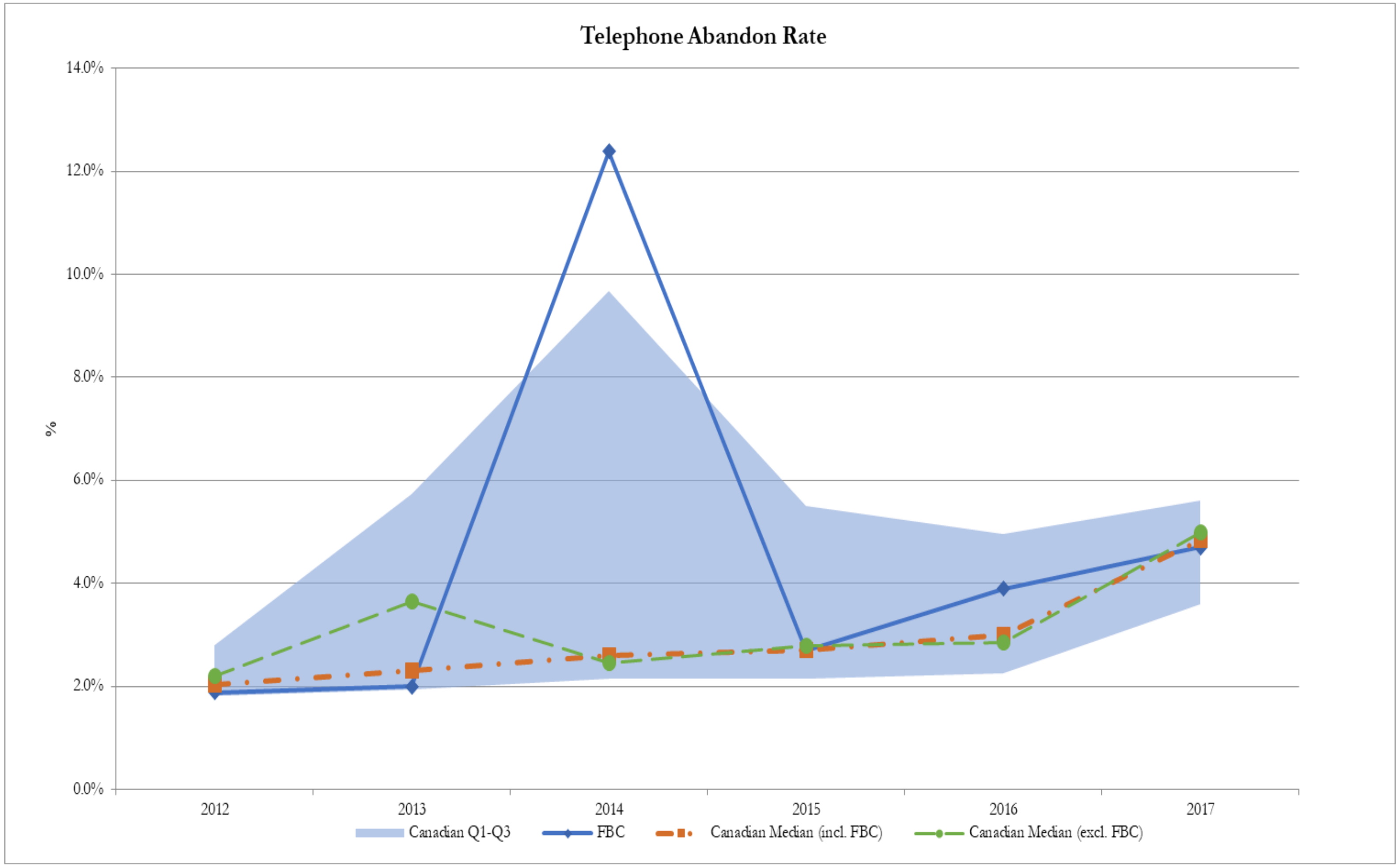
Appendix – FBC
20. Telephone Service Factor – Non-Emergency



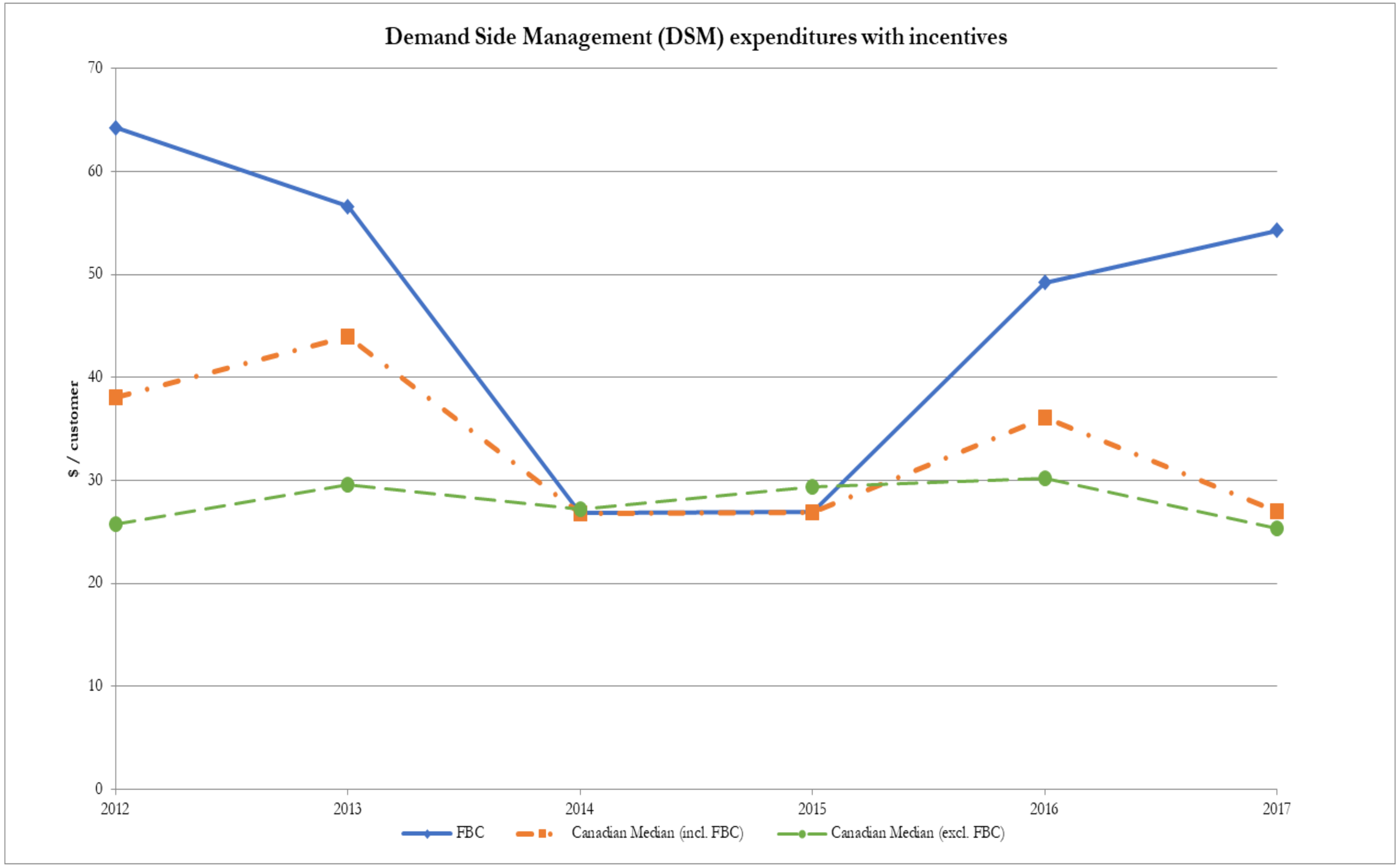
Appendix – FBC
21. First Contact Resolution



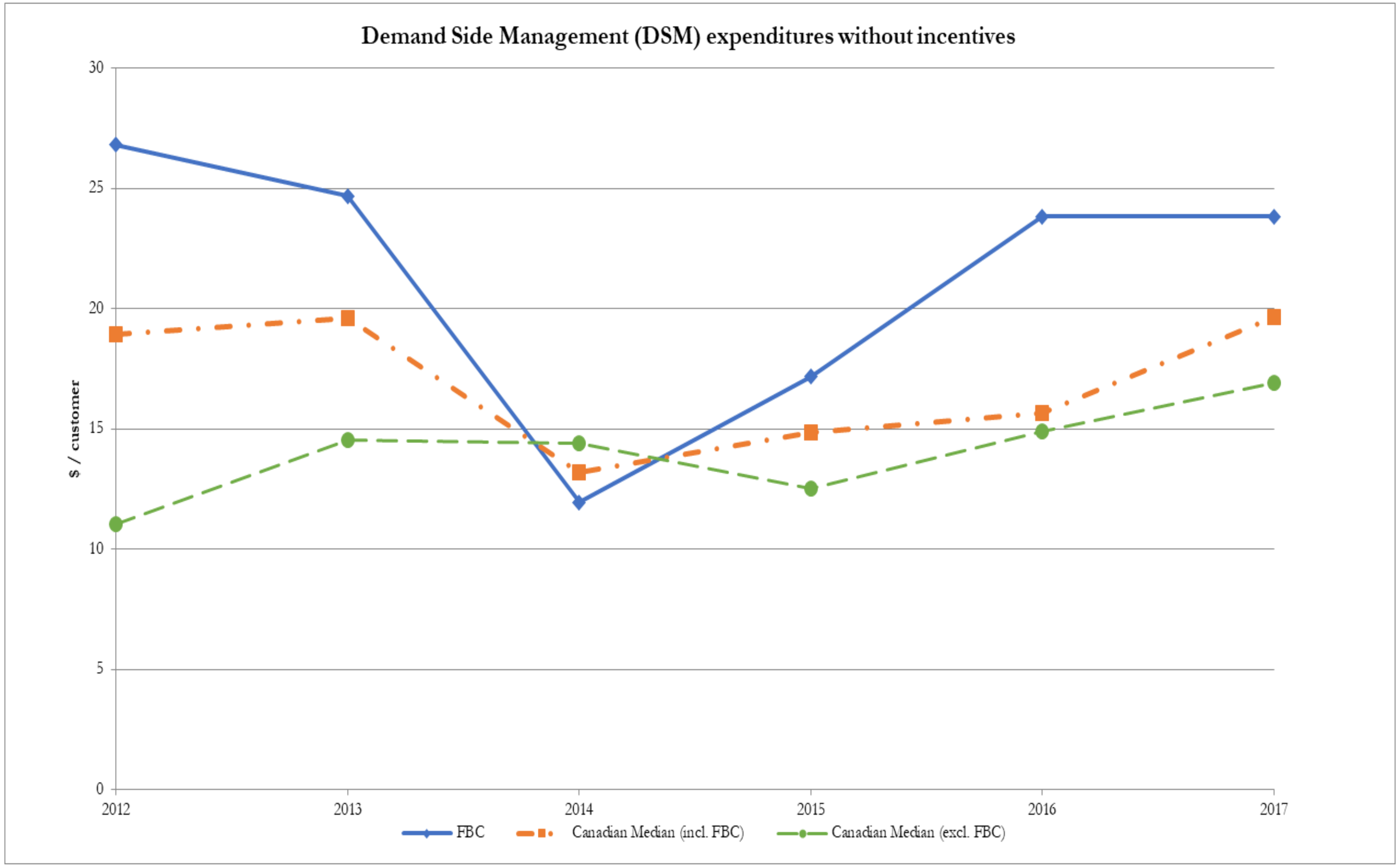
Appendix – FBC
22. Telephone Abandonment Rates



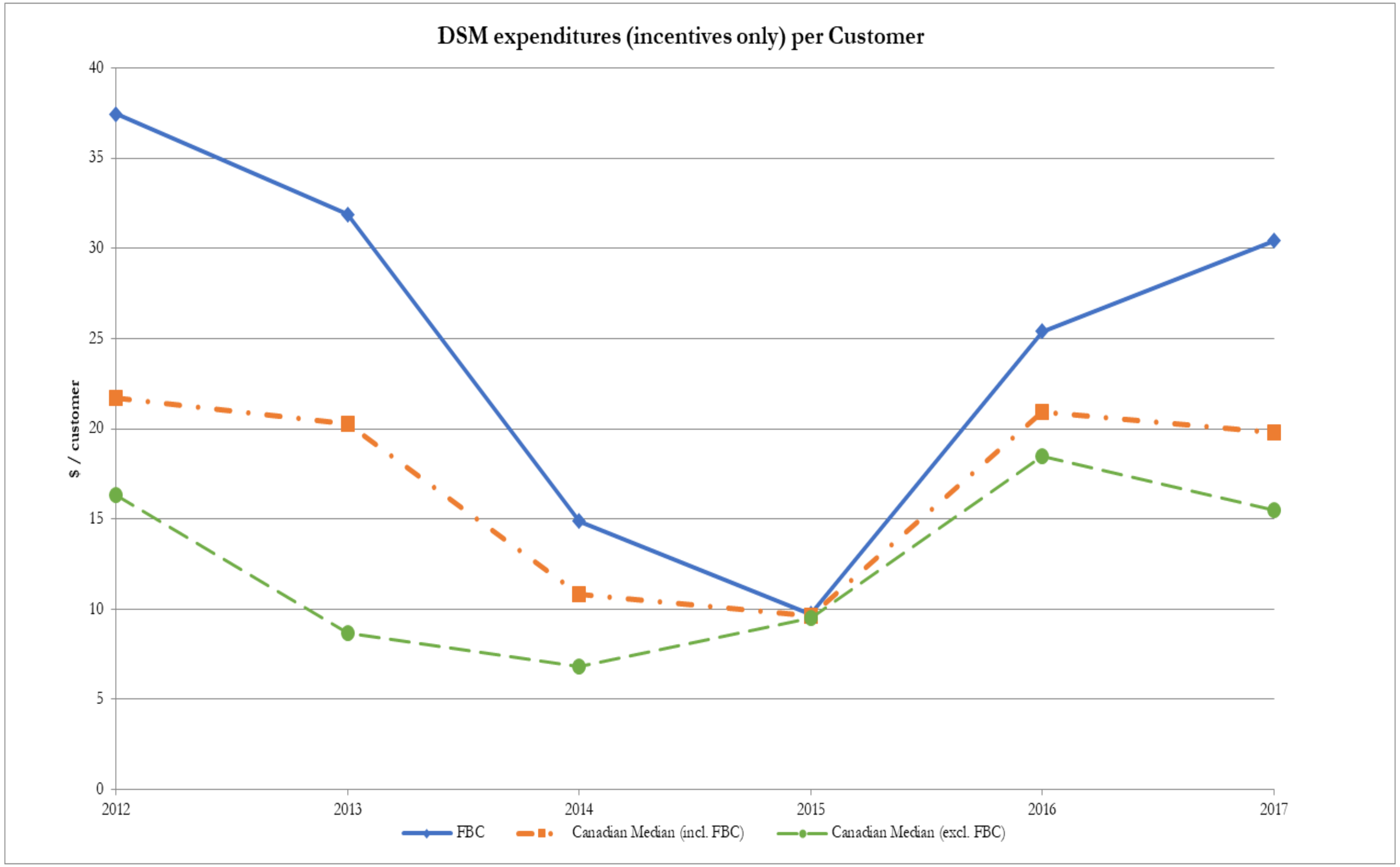
Appendix – FBC
23. DSM Expenditures (with incentives)/Customer



Appendix – FBC
24. DSM Expenditures (without incentives)/Customer



Appendix – FBC
25. DSM Expenditures (incentives only)/Customer



FortisBC Energy Inc. and FortisBC Inc. Benchmarking Study

CONCENTRIC ADVISORS

2018

FORTISBC

BENCHMARKING STUDY WORKSHOP

MINUTES

November 13, 2018
9:00 am – 12:00 pm
1125 Howe Street, Vancouver, B.C.

Workshop Agenda

Attached is a copy of the workshop material.

The document named "Introduction Section – Benchmarking Study Workshop – November 13, 2018" are the slides covering the Introduction, Agenda and Stakeholder Consultation process.

The document named "Concentric Workshop Presentation with Appendices November 13" are the slides prepared by Concentric providing highlights of the FEI and FBC benchmarking studies.

PDF Concentric Workshop Presenta

PDF Introduction Section - Benchmark

The following documents are the handouts as referred to during the workshop.

- Summary of Stakeholder Comments Regarding Benchmarking Study
- Draft Benchmarking Study Terms of Reference
- List of Benchmarking Consultants

PDF Summary of Stakeholder comme

PDF Benchmarking Study Terms of Refe

PDF List of Benchmarking Cons

Participants at the meeting:

FortisBC

- James Wong, Rouzbeh Mehrazma, David Perttula, Brandi Paulson

B.C. Municipal Electrical Utilities (BCMEU)

- Dan Geissler

Commercial Energy Consumers Association (CEC)

- David Craig, Janet Rhodes

Industrial Customer Group (ICG)

- Robert Hobbs

MoveUP

- Jim Quail
- Mark Stauft (consultant) – phone

BC Sustainable Energy Association (BCSEA)

- Bill Andrews
- Tom Hackney – by phone

BCUC Staff

- Yolanda Domingo, Jackie Ashley, Bonnie Guzman

Highlights

Outlined below is the agenda for the workshop.

<u>Agenda</u>

- Introductions – FortisBC (10 minutes)
- Overview and Background – FortisBC (purpose of study, recap of discussions to date, terms of reference and selection of consultant) (15 minutes)
- Approach to Benchmarking – Concentric (20 minutes)
- Highlights of FEI Benchmarking Study – Concentric, with General Discussion by All (50 minutes)
    - Review results and findings
    - General discussion
- Break (15 minutes)
- Highlights of FBC Benchmarking Study – Concentric, with General Discussion by All (50 minutes)
    - Review results and findings
    - General discussion
- Summary and Wrap-up (20 minutes)

FortisBC provided an overview of the BCUC Directive from the 2014 PBR Decision providing direction and guidance for the Benchmarking Study (slide number 3).

FortisBC provided a list of stakeholders involved in the Benchmarking Study (slide number 4).

FortisBC provided guidance regarding the PACA funding for the workshop participants.

FortisBC provided a recap of the consultation activities undertaken with stakeholders for the Benchmarking Study (slides 5, 6, 7, 8).

Discussion occurred regarding the choice of metrics for the Benchmarking Study Terms of Reference. ICG asked that a comparison of customer rates against other utilities including BC Hydro be included as part of the Benchmarking Study. ICG commented that while customer rates are a blunt proxy for efficiency, a comparison would be useful in providing a high level comparison of utilities. Additionally, ICG noted that the requested customer rate comparison would be easy to prepare as the data is publicly available. CEC stated their support for ICG's requests. Other stakeholders commented that there are many factors that influence customer rates, making it difficult to draw meaningful conclusions from the customer rate comparison. During the discussion, noted was that BC Hydro was already producing the information for its use and that perhaps ICG can access that information to find the information it is looking for. One participant commented that this information can be retrieved as part of the discovery process of the PBR proceeding.

FortisBC stated its concerns about including a comparison of customer rate information as part of the Benchmarking Study. The concerns included that customer rates may be affected by a number of different factors and that customer rates have a weak link to the overall efficiency of the utility. After discussion, FortisBC offered two solutions for ICG to consider. FortisBC offered to help ICG in obtaining the requested data but that it not be included as part of the Benchmarking Study. FortisBC also suggested that ICG can request the information as part of an information request in the anticipated regulatory proceeding on review of the company's next multi-year rate plan (MRP) and the Benchmarking Study.

ICG stated that the two options outlined were not what it had requested. ICG stated that it is requesting the customer rate comparison information be included as an attachment/appendix to the Benchmarking Study.

Discussion occurred regarding CEC's comments submitted on the proposed Benchmarking Study. FortisBC provided a high level overview of CEC's comments and asked if CEC wanted to elaborate. Some stakeholders expressed interest in seeing a copy of CEC's comments. After obtaining CEC's approval to distribute their comments as part of these draft minutes, attached are CEC's comments.

PDF

CEC Comments -
Review of Benchmar

Concentric reviewed the Approach to Benchmarking Study and discussed the results and findings for FEI and FBC. Refer to the Concentric Workshop presentation slides.

Highlights of Benchmarking Study as presented by Concentric

During the review and discussion, stakeholders suggested some formatting and labelling changes to facilitate understanding of the Benchmarking Study information in the final report. The suggestions included:

- For any acronyms used (e.g. CAGR – compound annual growth rate), define the acronym.
- To ensure clarity, include the definition of the metric as part of the labelling of the graph. For example, for Telephone Service Factor (TSF) metric, include or replace reference to TSF with "Number of Calls Answered within 30 seconds".
- The green and red highlighting used on the table "Highlights of Benchmarking Study" (i.e. slides 22 and 32) needs to have a description to explain the meaning of the colours red and green.

Discussion occurred regarding the formatting and the information that are included in the graphs. Clarification was provided by Concentric on the quartile information and the meaning of the shaded regions on the graphs (i.e. middle 50%).

Following are some of the comments raised and feedback provided by stakeholders. Not all comments have been noted as the comments were generally to help clarify the information for understanding and discussion at the workshop.

<u>FEI section</u>

Comments and questions received from stakeholders included:

1. Clarification was requested on whether the O&M and Net Plant results (e.g. slide 16) were presented on a nominal basis or a real basis. Concentric noted that the results as presented at the workshop were on a nominal basis.
2. How do the results take into consideration the mix of residential and large commercial and industrial customers? For example, can the O&M results be separated (or weighted) by customer class? Concentric clarified that it had not separated the results by customer type and that doing so would require detailed cost of service allocation (COSA) modelling in which the costs are allocated to various rate classes according to appropriate allocators. Concentric noted that COSA analysis was not part of its scope of work and would be very difficult to do for individual companies as Concentric did not have access to the necessary detailed data to do so. COSA modelling is ordinarily conducted as part of companies' rate design proceedings.
3. Clarification was requested on whether the volumetric data used in some of the metrics were based on weather normalized data. Concentric confirmed that the volumetric data reported was based on actual consumption data. Concentric noted that they have relied on actual volumes for a number of reasons including that actual volumes are publicly available and consistently reported. In addition, Concentric considers the fact that, while the non-commodity portion of O&M will not vary based on

the volumes to the same extent that commodity costs will (if at all), the system is designed to meet the actual volume and not just the normalized volume.

4. A question was asked as to how the benchmarking study would be used in the context of the company's next MRP application. FortisBC commented that consistent with the BCUC directive, the Benchmarking Study along with other considerations were intended to inform the BCUC's decision on the determination of the X-Factor for its next MRP.
5. A suggestion was made to include a metric based on the quantities (in kilometers) of pipeline/wires and cost per kilometer to reflect the size of each company's distribution system and the impact on costs. FortisBC is discussing this issue with Concentric.

<u>FBC section</u>

Comments and questions received from stakeholders included:

1. A question was asked whether there were any metrics that address capital expenditures. Specifically, how is the issue of overspending of the capital formula that FortisBC is experiencing assessed as part of the Benchmarking Study. FortisBC commented that capital expenditures are incorporated into the Net Plant metric and that the issue it is currently experiencing with capital expenditures higher than allowed under the current PBR Plan is not necessarily an indication of efficiency/inefficiency but more a function of funding provided for under the approved formulaic approach. Concentric further noted that in its view, net plant per customer already captures capital expenditures per customer to a reasonable degree. Specifically, the change in net plant per customer in Concentric's calculations incorporates capital additions, less retirements and annual depreciation. As such, the metrics Concentric has analyzed related to net plant already capture FEI's and FBC's financial efficiency in terms of their respective levels of fixed assets
2. A question was asked as to what the intended use of the Benchmarking Study would be if the next Regulatory Framework was instead a Cost of Service versus a PBR Plan. FortisBC commented that the study was intended for the next PBR, as stated in the BCUC directive, however the benchmarking information would be relevant under other forms of regulation as well. Noted also was that the analysis and information provides efficiency and service level information for consideration.
3. During the discussion of the Net Plant per customer metric, reasons were suggested as to why some companies' Net Plant per customer may be higher or lower. Concentric noted that it sometimes depends on the phase of the capital spending cycle that each company may be in. FortisBC was asked what phase of the capital spend cycle that it currently is at. **FortisBC agreed to take the request as an undertaking and provide a response. FortisBC's response is provided below.**

   <u>FortisBC Energy Inc. (FEI)</u>

   FEI has been in a sustainment capital spend cycle up until approximately 2012/13. This coincided with the conclusion of a number of large capital projects (i.e. Southern Crossing Pipeline and Mt. Hayes LNG) and relatively stable customer additions. Capital projects were primarily driven by the need to address condition and integrity related issues.

Starting in 2014, FEI moved into a period of sustained growth and the associated capital expenditures to attach unprecedented numbers of new customers and undertake system improvements to address capacity concerns. As well, changes in industry practices and inspection technology and aging infrastructure result in an increased focus on system integrity which results in significant increases in CPCN projects (i.e. Lower Mainland Intermediate Pressure System Upgrade, Inland Gas Upgrades, Transmission Integrity Management Capabilities). There is an infrastructure issue in North America where assets installed in the 1950s and 1960s are nearing their end of life. FEI is no exception to the infrastructure issue with half of its assets over 30 years old. The elevated level of capital expenditures is expected to continue for the near to medium-term (i.e. 1 to 5 years).

<u>FortisBC Inc. (FBC)</u>

FBC has been in a sustainment capital spend cycle since approximately 2011 following the completion of numerous major system reinforcement (i.e. capacity) projects. FBC is continuing to invest in reliability related capital expenditures for Generation (i.e. Upper Bonnington Old Units Refurbishment, Corra Linn Dam Spillway Gates) and Network Operations. For customer growth capital, the prospects of adding new loads associated with greenhouses and data centres may result in increased growth expenditures in the coming years, but this potential load growth is still uncertain.

4. A question was asked as to whether the number of customers in the unit cost metrics included the indirect customers of FBC. Concentric noted that each wholesale customer was counted as one customer only. Noted also was that the costs being compared do not include the wholesale customers' costs to serve or support each individual customer.

FortisBC stated that the final Benchmarking Study will be included in the company's next MRP filing expected in early 2019.

The workshop concluded with FortisBC expressing appreciation for stakeholders' time and their input and feedback provided.

Appendix C3

STAKEHOLDER COMMUNICATIONS

FortisBC Next Generation PBR

Stakeholder Discussion

October 2018

Energy at work FORTIS BC™

Agenda

- Highlights of the Current PBR Plan
- Next Generation PBR Application
- Key Themes
  - Engagement
  - Investment
  - Innovation
- PBR Questions and Discussion
- Benchmarking Study Update

2014-2019 PBR Review

O&M

Capex

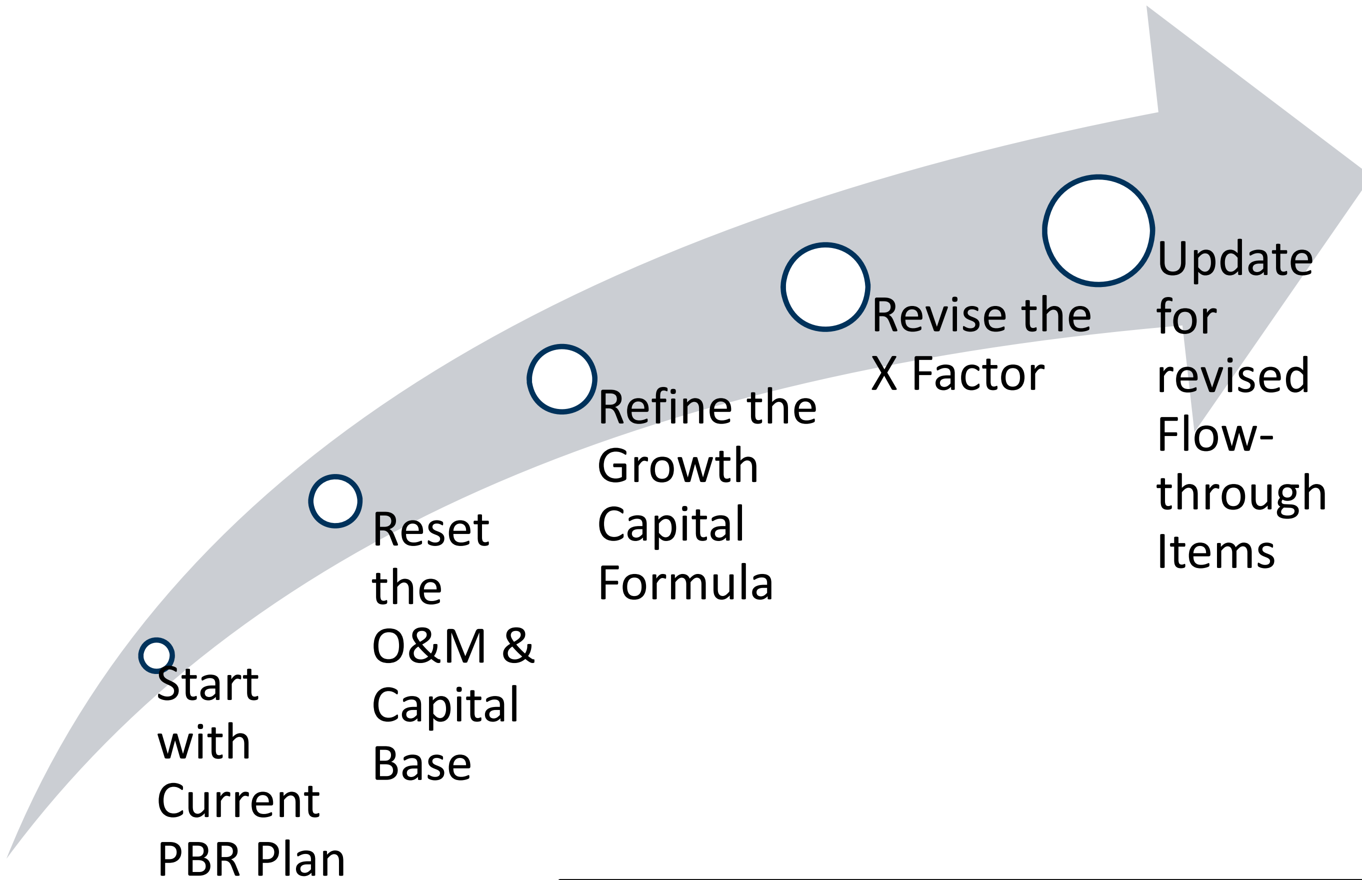
SQIs

Rates

Annual Review provides opportunity to review progress and discuss results

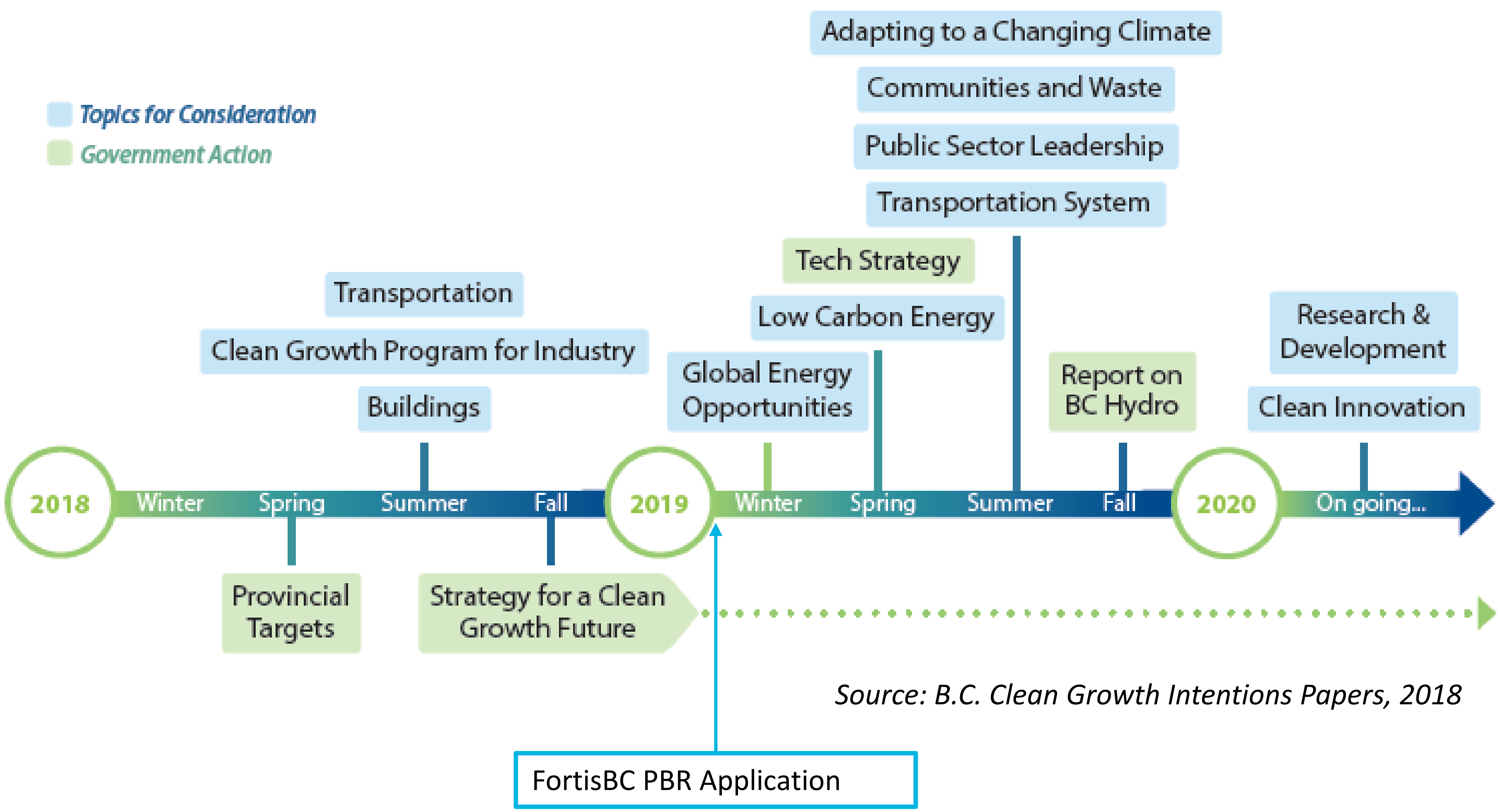
Overall, PBR has been successful

Next Generation PBR (2020- 2024)



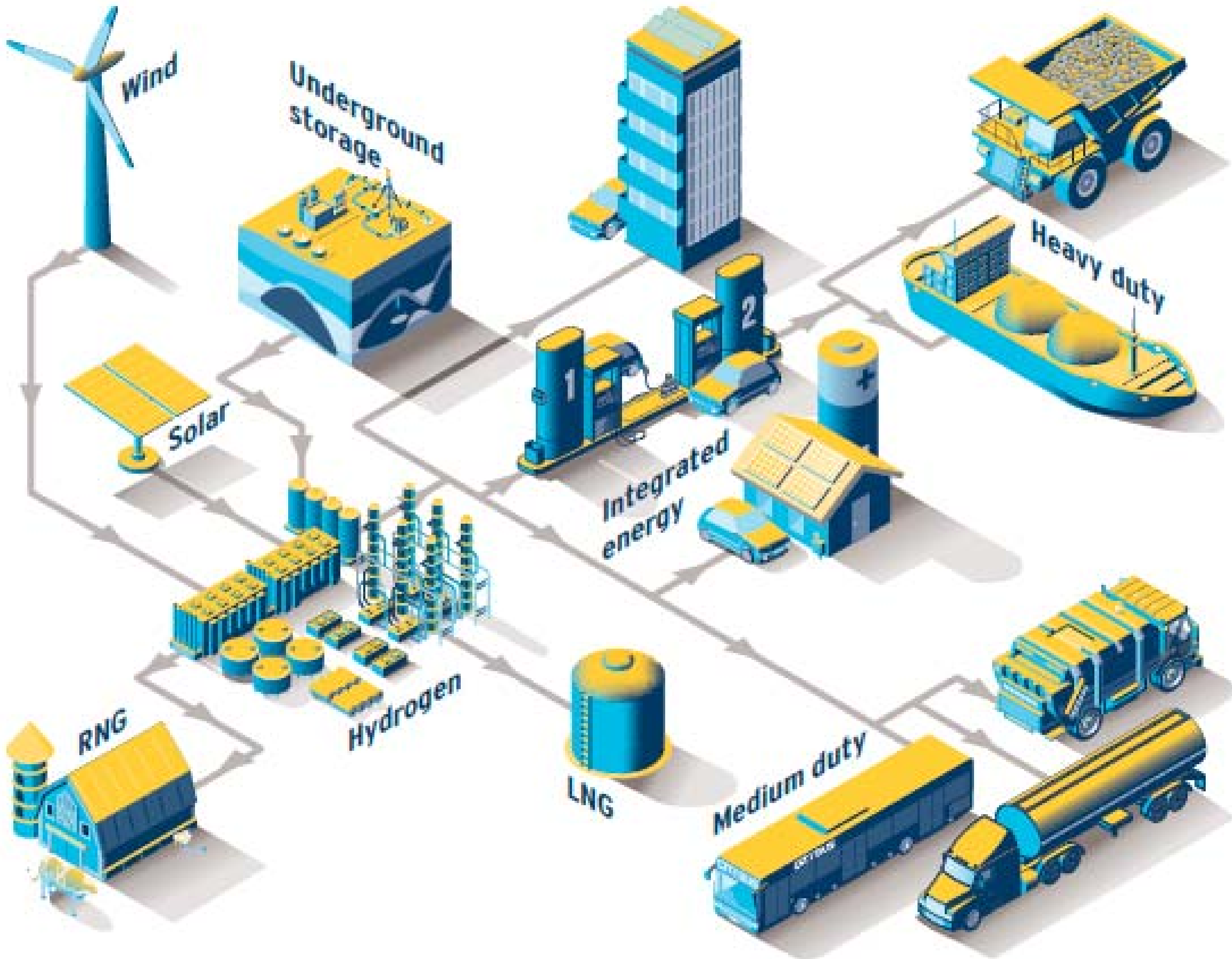
Application to be filed early in 2019

B.C.'s Clean Growth Future

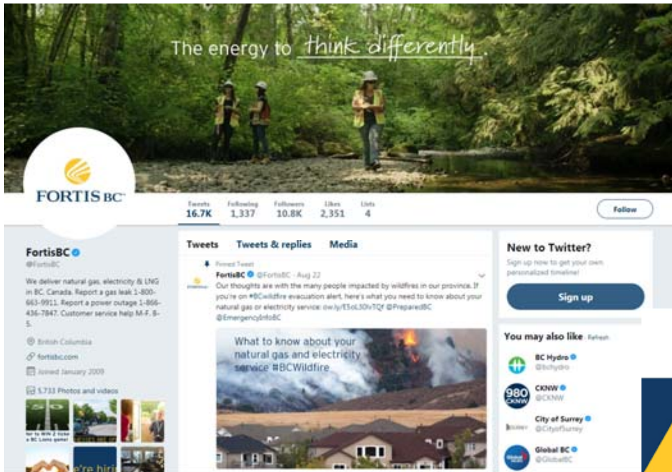


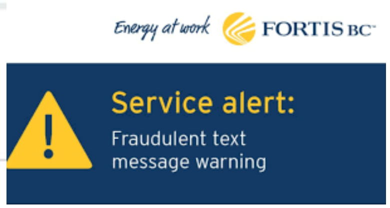
Source: B.C. Clean Growth Intentions Papers, 2018

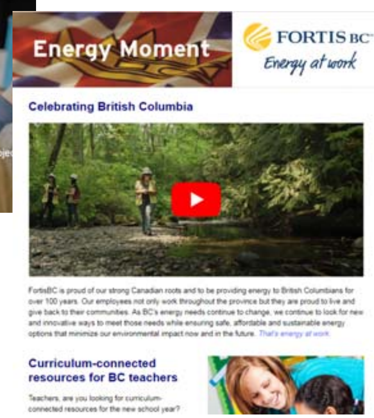
FortisBC's Clean Growth Pathways



Stakeholder Engagement

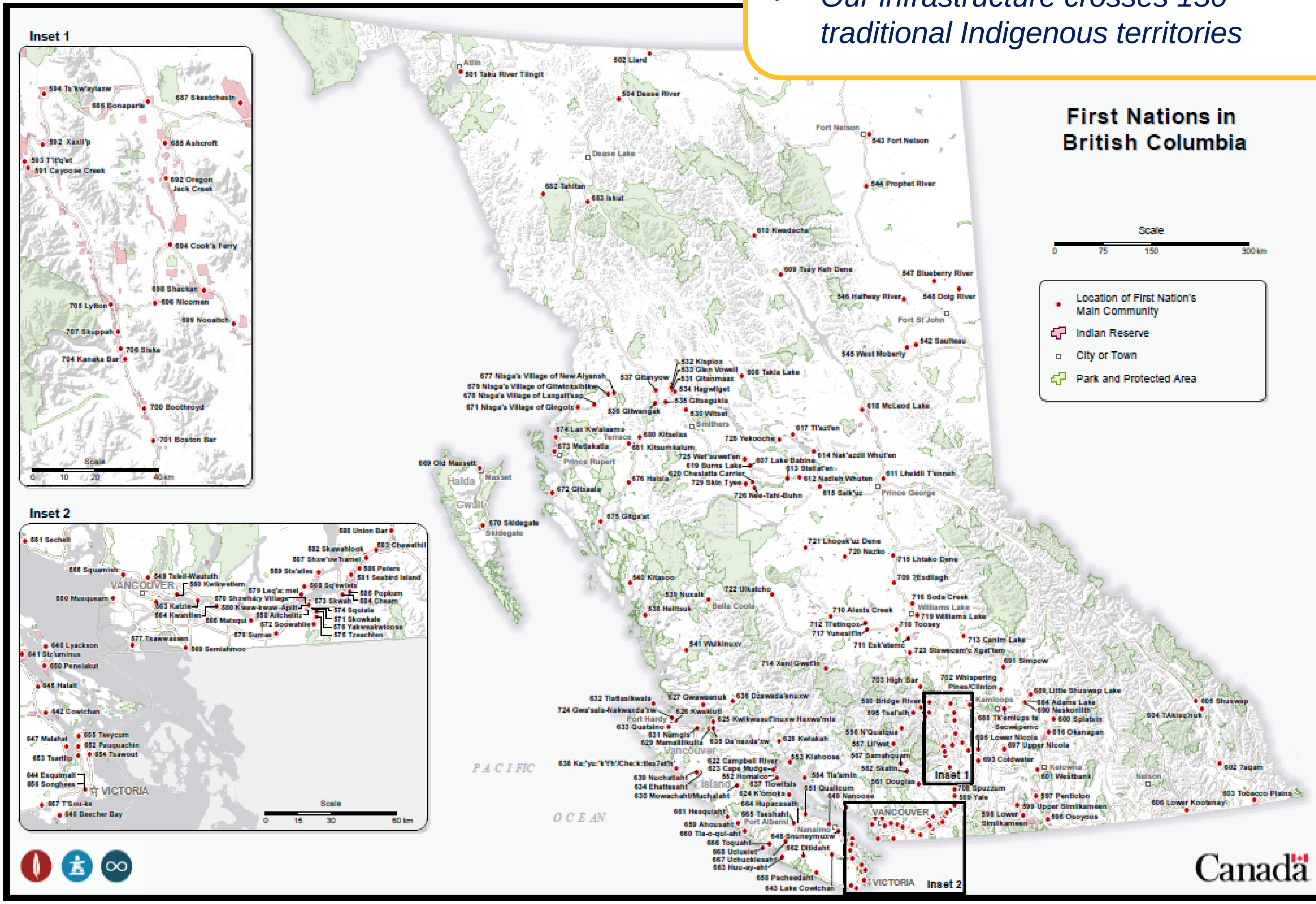






Indigenous Relations

- *FortisBC provides service to 56 Indigenous communities*
- *Our infrastructure crosses 150 traditional Indigenous territories*



Investing to support growth and sustain our assets

Capital investments are necessary to ensure ongoing safe, reliable, and environmentally responsible operations

- Gas pipelines and facilities
- Electric stations and network
- General Plant

2014 PBR resulted in capital challenges for both Gas and Electric

- Unforeseen levels of growth
- Unanticipated projects

For 2020, will be considering changes to formula drivers and project categorization

Investing to support growth and sustain our assets

Electric

- Mechanism to deal with larger projects that are lower than CPCN threshold
- Reviewing trends in reliability

Gas

- Proposing integrity projects to enhance in-line inspection capabilities
- CPCN for retrofits to Interior small diameter transmission lines
- CPCN for retrofits to allow use of crack detection tools in larger diameter transmission lines

General Plant

- Fleet, Facilities, and Information Systems
- No major changes other than new investments in Innovation

Innovation funding

- FortisBC intends to apply for funding to support Innovation
  - Research and development
  - Pilot programs
- Customer demand
  - Demonstrated demand for low emission products such as Renewable Natural Gas and electric vehicles
  - Affordability and climate are top priorities
- Government policy
  - Clean growth future strategy
  - Carbon pricing
  - Clean Fuel Standard
  - Fugitive methane regulations
  - Building step codes and net zero codes

Innovation funding principles

- Use a portfolio approach to diversify risks
- Leverage partnerships
- Manage portfolio centrally to ensure maximum value
- Pursue innovations with strong consumer interest and/or policy benefit
- Leverage FortisBC's regulated assets and expertise
- Focus on technologies that have focus on solutions that address challenges and opportunities unique to BC or are otherwise undeveloped

Innovation funding initiatives

- New RNG sources
- Using hydrogen to decarbonize natural gas
- EV charging technologies
- Carbon capture technologies
- Behind the meter
- Natural gas and hydrogen for transportation

FortisBC PBR
Questions and Discussion

Energy at work FORTIS BC™

Benchmarking Study Update

- Progress made
- Consultant – Concentric
- Metrics include:
  - Financial
  - Customer Service
  - Reliability
- Workshop scheduled to provide highlights
  - Tuesday November 13
  - BCUC Hearing Room, 12th Floor, 1125 Howe St, Vancouver

Review of Multi-Year Year Rate Plans and Cost of Service Regulation

December 14, 2018

Energy at work FORTIS BC™

Agenda

- Introductions
- Results of Workshop Survey
- Multi-Year Rate Plans and Cost of Service Regulation – Dr. Lawrence Kaufmann
- Summary and Wrap-up

Energy at work FORTIS BC™

Workshop Survey

8 entries in survey; 3 completions, remaining 5 incomplete

Q1. One of the reasons for implementing MRPs/PBRs is their ability to incent the utility to reduce costs and increase efficiency. Some argue that the utilities have a mandate to be efficient and do not need additional incentives to do so. Which option below reflects your personal opinion about whether regulation should provide stronger efficiency incentives for utilities?

Total: 4 participants

		Total
1	Agree that utilities should be incented to be more efficient and promote innovative solutions to utility challenges.	1 25%
2	Somew hat agree that the utilities should be incented to find additional efficiencies and strive for innovative solutions; how ever the benefits should be shared ratepayers during the MRP term as w ell.	0 0%
3	Utilities already receive incentives under cost of service regulation and have a mandate to perform efficiently. No need for incremental incentives.	2 50%
	Did not answ er	1 25%

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Workshop Survey

Q1 comments from participants

- The regulatory compact establishes a duty to manage the utility prudently and to provide safe, reliable service at reasonable rates.
- Public utilities' franchises should come with an obligation and duty to the public to be efficient and keep rates as low as possible. After all, where else can one get 7+% guaranteed rate of return?

Energy at work FORTIS BC™

Q2. A list of regulatory objectives is provided below. Please rate how effectively you believe each objective is promoted by **performance-based regulation** on a scale of 1 to 5. (5=very effectively, 1=not effectively)

Total: 3 participants

	1 = not effectively	2	3	4	5 = very effectively
Operational and planning certainty	1	1	0	1	0
	33%	33%	0%	33%	0%
Incentives for O&M savings	1	0	0	2	0
	33%	0%	0%	67%	0%
Incentives for capital expenditure efficiencies	2	0	0	1	0
	67%	0%	0%	33%	0%
Regulatory efficiency	1	0	0	2	0
	33%	0%	0%	67%	0%
Regulatory scrutiny	2	0	0	1	0
	67%	0%	0%	33%	0%
Sharing of benefits between ratepayers and utility during plan's term.	1	0	1	1	0
	33%	0%	33%	33%	0%
Service quality monitoring	2	0	0	1	0
	67%	0%	0%	33%	0%
Safeguards against unexpected events	2	0	0	1	0
	67%	0%	0%	33%	0%
Rate stability	1	0	0	2	0
	33%	0%	0%	67%	0%
Customer benefits	1	1	0	1	0
	33%	33%	0%	33%	0%
Ease of understanding	2	0	0	1	0
	67%	0%	0%	33%	0%

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Workshop Survey

Q2 comments from participants

- The regulator should perform independent and intensive on-site performance and financial audits once per PBR cycle to verify integrity of O&M cost reporting and capital distribution.
- I cannot answer these questions meaningfully without context and without instructions from my client.

Energy at work FORTIS BC™

Q3. A list of regulatory objectives is provided below. Please rate how effectively you believe each objective is promoted by **cost of service regulation** on a scale of 1 to 5. (5=very effectively, 1=not effectively)

Total: 3 participants

	1 = not effectively	2	3	4	5 = very effectively
Operational and planning certainty	0	0	0	2	1
	0%	0%	0%	67%	33%
Incentives for O&M savings	0	1	0	1	1
	0%	33%	0%	33%	33%
Incentives for capital expenditure efficiencies	0	1	0	1	1
	0%	33%	0%	33%	33%
Regulatory efficiency	0	1	0	1	1
	0%	33%	0%	33%	33%
Regulatory scrutiny	0	0	0	2	1
	0%	0%	0%	67%	33%
Sharing of benefits betw een ratepayers and utility during plan's term.	1	0	0	1	1
	33%	0%	0%	33%	33%
Service quality monitoring	0	1	0	1	1
	0%	33%	0%	33%	33%
Safeguards against unexpected events	0	1	0	1	1
	0%	33%	0%	33%	33%
Rate stability	0	0	1	2	1
	0%	0%	33%	67%	33%
Customer benefits	0	1	0	1	1
	0%	33%	0%	33%	33%
Ease of understanding	0	0	0	2	1
	0%	0%	0%	67%	33%

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Workshop Survey

Q3 comments from participants

- Cost of Service applications allow for greater examination of costs. Independent audit by regulator should still happen once every 5 years (on-site, and visibility of each process, perhaps over one-month duration). Expensive, but worth it.

- As per the last one - needs context and I require instructions

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Q4. Please rank the following topics from the greatest interest to the least interest for workshop discussions.

Topics with greatest interest

Fundamental comparison of cost of service rate setting and MRP rate-setting.	1	2	3
Type of multi-year rate plans (revenue cap, price caps, customer plans,..) and I-X indexing formulas	1	2	4
Service quality indicators	2	3	4
Term: longer duration of MRP plans	1	3	6

- Total participants 3
- Rankings as noted with 1 as the greatest interest and 11 as the least interest

Energy at work FORTIS BC™

Q5. Advancing the development of Innovative Technologies for the benefit of customers and to support government policy will be a key theme of FortisBC's next ratemaking application. FortisBC intends to apply for funding to support research and development and pilot programs. Please choose one of the following options indicating how much you think customers are willing to pay to support Innovation Technologies.

Total: 3 participants

		Total
	Total	3
1	Up to $5 per customer per year	1
		33%
2	Betw een $5 and $10 per customer per year	1
		33%
3	Greater than $10 per customer per year	1
		33%

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Workshop Survey

Q5 comments from participants

- Require more information to answer meaningfully but our client is committed to the evolution and growth of the companies.
- Utilities shouldn't pay for R&D on the backs of ratepayers.

Multi-Year Rate Plans and Cost of Service Regulation

Larry Kaufmann

President, Kaufmann Consulting

December 14, 2018

Overview

This presentation addresses the merits of multi-year rate plans (MRPs) compared to cost of service regulation (COSR)

- Performance-based regulation, MRPs and COSR defined
- Incentives/"carrots" vs. Mandates/"sticks" as rival regulatory approaches
- Criteria for assessing "success" of MRP plans
- Appendix: MRP Experience in Selected Jurisdictions
    - Alberta
    - Ontario
    - Massachusetts

Cost of Service, PBR and MRPs Defined

Cost of Service Regulation

Rates for regulated services set to give utilities a reasonable opportunity to recover their prudently incurred cost of service, including the costs of capital

- "Prudent" costs not straightforward to identify
    - Appropriate cost measures/definitions
    - Appropriate cost allocations
    - "Used and useful" assets
    - Sometimes little emphasis on performance/efficiency *per se* because difficult to evaluate

Cost of Service Defined (Con't)

Under COSR, new rates are proposed by the utility in general rate cases presented to the regulatory commission

- Company provides wealth of information on costs and billing determinants as basis for proposed new prices
  - >> Inherently information-intensive process
- Company evidence reviewed/challenged by Commission staff and interveners
  - >> Often slow, costly and contentious
- Commission evaluates all evidence presented and makes a determination on what rate levels are "just and reasonable"

Cost of Service Defined (Con't)

COSR has been used in North America for nearly a century and in many ways has to be considered a success

- Extensive, highly reliable energy utility networks constructed under COSR
- Near-universal electric (and to a lesser extent, gas) service in Canada and the US
- Energy service affordable for most consumers

  >> Consumers protected against monopoly power

- Source of relatively low-risk returns for shareholders, with legal rights for shareholders to earn a fair rate of return on capital

Cost of Service and PBR Defined (Con't)

Nevertheless, COSR has been increasingly criticized by practitioners and academics

What are the problems with COSR?

According to one regulatory commission, "well-known defects" of COSR include:

- Weak incentives for cost control
- Inefficient allocation of resources
- Disincentives for innovation
- Costly method of regulation

Massachusetts Department of Public Utilities, D.P.U. 94-158, p. 9

Cost of Service and PBR Defined (Con't)

Two-pronged response:

- Introduce competition into utility services where competition is feasible
  - Implemented for traditionally regulated utility services such as gas supply and power generation
  - Distributed energy resources and energy storage making competition more prominent in energy *delivery* services
- Introduce "performance-based" regulation, designed to emulate and replicate competitive market forces, for regulated services
  - COSR designed to protect against monopoly power of companies granted a monopoly franchise, not encourage efficiency *per se*

PBR and MRPs Defined

Performance Based Regulation

A set of regulatory rules that create incentives for utilities to achieve regulatory objectives (*e.g.* productive operations, low cost of service, appropriate service quality)

Many different variants of PBR, but in general they are more rule-based and formula-based than COSR

Most common form of PBR is the multi-year rate plan (MRP)

PBR and MRPs Defined (Con't)

MRPs establish rules for updating rates over multi-year period

Rate changes typically set through an "inflation minus X" formula

This formula-based approach differs from the detailed, forensic examination of utility costs used to set rates under COSR

MRPs often provides utilities more operating flexibility than COSR and the ability to earn higher returns *if* they operate more efficiently under the plan

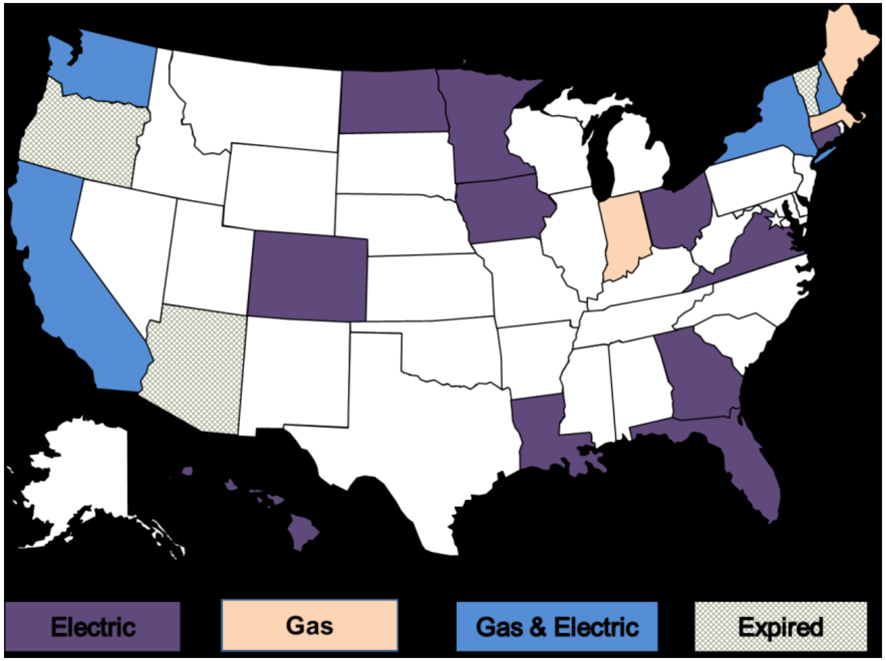
Cost of Service Regulation vs. MRPs

Although COSR has been dominant in North America for decades, MRPs are actually more common than COSR in the rest of the world

Most newly-established regulatory commissions, regulating utilities for the first time, have opted for MRPs rather than explicit COSR

There are also many examples of MRPs in Canada and the U.S.

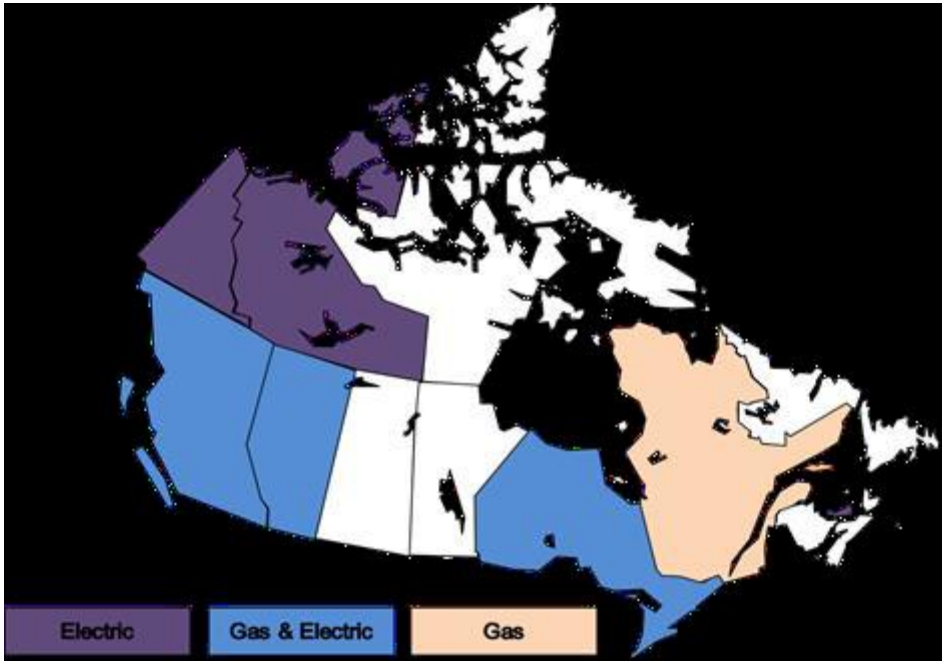
Multi-Year Rate Plans in the United States



MRPs are used in many states today to regulate utilities.

Source: State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities – July 2017

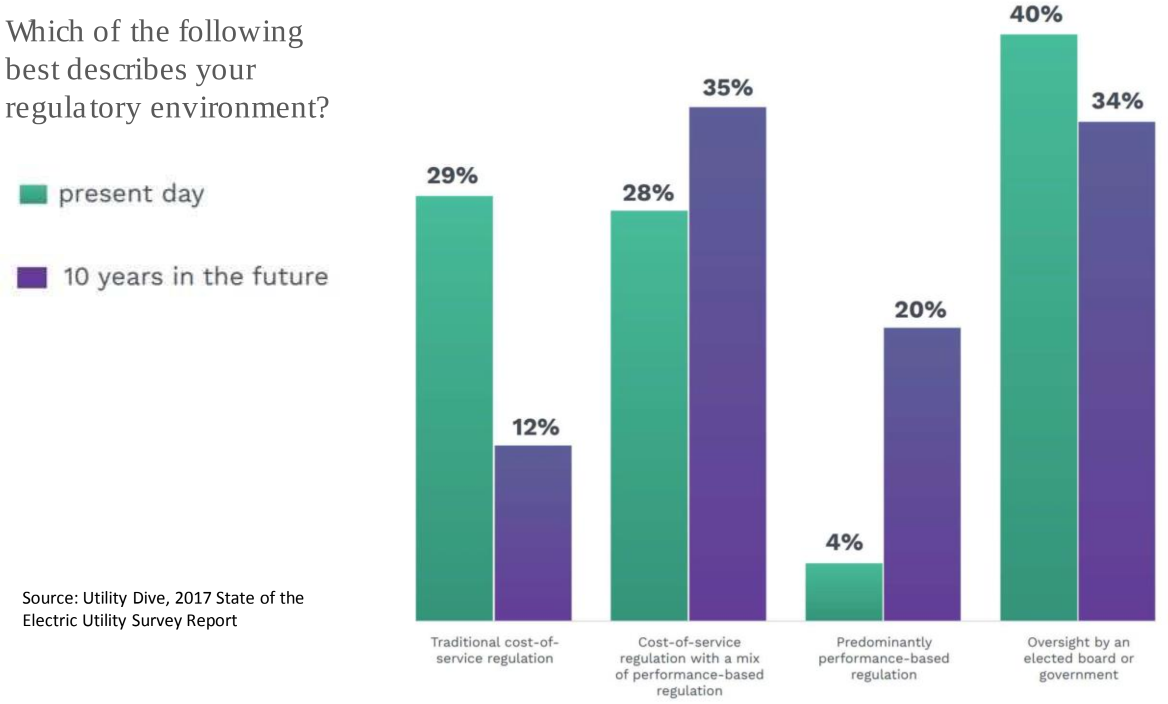
Multi-Year Rate Plans in Canada



In Canada, many investor owned utilities have MRPs.

Source: State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities – July 2017

Future of Electric Regulation (Survey)



Source: Utility Dive, 2017 State of the Electric Utility Survey Report

Continuing shift away from traditional cost of service regulation.

Source: 2017 State of the Electric Utility Survey – Utility Dive

How Do MRPs Create Incentives?

Multi-year PBR plans create incentives in several different ways

- Longer-term framework promotes longer-term planning and initiatives
- Often more stable framework than COSR
- Rate changes “decoupled” from reported costs while MRP is in place
- Less burdensome regulation allows more management attention to be focused on “basic business” rather than the regulatory process
  - >> More incentivized environment and corporate culture
  - >> More potential for “discovery” and innovation

How Do MRPs Create Incentives? (Con't)

All these factors promote more efficient behavior

More efficient behavior, in turn, creates the potential for returns that exceed the allowed ROE if utility meets or exceeds "benchmarks" embedded in plan

- Productivity targets in rate/revenue trajectory
- Performance indicators

More efficient behavior also leads to lower unit costs, which in turn leads to lower prices for customers

>>> profit motive in MRPs leads to "win-win" outcomes

Incentives/“Carrots” vs. Mandates/“Sticks”

Fundamental philosophical difference between COSR and MRPs/PBR is the best means of achieving regulatory objectives

COSR: emphasizes extensive review process to uncover appropriate costs and mandates and ”sticks” if utility falls short *e.g.* cost disallowances for imprudent behavior

MRPs: emphasizes incentives and “carrots” that encourage utilities to be efficient and innovative

Incentives/“Carrots” vs. Mandates/“Sticks” (Con’t)

Extensive experience shows that competition – driven by the profit motive – is more successful than central planning and mandates in promoting efficiency, innovation and customer benefit

Experience goes well beyond utility industries

Broad movement away from central planning and towards competition/market forces in last two generations

Incentives/"Carrots" vs. Mandates/"Sticks" (Con't)

MRPs attempt to replicate competitive market incentives in plan design and rate adjustments

- Price trends under MRPs and competitive markets are both decoupled from utility's own cost, which creates stronger incentives to:
  - Control unit cost and enhance productivity
  - Pursue new revenue opportunities
- The "competitive market paradigm" used to set "Inflation – X formulas" leads to price changes that are decoupled from company's own costs but still satisfy the "just and reasonable" standard

Incentives/"Carrots" vs. Mandates/"Sticks" (Con't)

MRPs therefore bring the forces motivating efficient behavior in competitive markets to bear on regulatory ratemaking

Simulating the *operation* of competitive markets likely to be more effective in promoting the *outcomes* of competitive markets, which is ultimately the goal of regulation

Incentives/“Carrots” vs. Mandates/“Sticks” (Con’t)

“The single most widely-accepted rule for the governance of the regulated industries is regulate them in such a way as to produce the same results as would be produced by effective competition, if it were feasible.”

Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, Volume 1, p. 17

MRPs focused on simulating both the operation and outcomes of competitive market forces in utility ratemaking

Criteria for Evaluating MRP Success

Well-designed MRPs create "win-win" outcomes for customers and shareholders

With that in mind, how can we assess whether a MRP is a "success"?

Below are a few common sense criteria for:

- Customers
- Shareholders
- Broader social objectives

Criteria for Evaluating MRP Success (Con’t)

Customers

1. Were there (real) price declines under the plan?
2. Was there price volatility under the plan?
3. Was the quality of service maintained or improved?

Shareholders

1. Did earnings improve?
2. Did other measures of financial health improve?

Broader Social Objectives

1. Did productivity improve?
2. Was the utility more innovative?
3. Were other social policy goals (*e.g.* clean energy) advanced by the plan?

Could MRP Results Have Been Attained Under COSR?

Another potential question: how do we know the same results could not have been obtained under COSR?

No one can ever know with certainty what might have happened if another path was chosen

But at least three factors imply MRPs can improve on COSR

Could MRP Results Have Been Attained Under COSR?

1. On a theoretical level, PBR is explicitly designed to create strong incentives to enhance productivity and be more innovative

   COSR was not explicitly designed for these purposes

   >> If there are positive outcomes under a PBR plan, it is not unreasonable to ascribe them to the *stronger* incentives created by the plan

Could MRP Results Have Been Attained Under COSR? (Con't)

2. The importance of "local" and/or firm-specific knowledge

   Who's better-positioned to understand what measures are most likely to succeed and improve utility performance?

   Utility employees and managers with decades of experience and unique, detailed, first-hand knowledge of operations

   Or

   Outside observers and analysts

   >>> Local and firm-specific knowledge only exists within the firm, and it could be an important source of performance gains if companies are appropriately incentivized

Could MRP Results Have Been Attained Under COSR? (Con't)

3. Performance improvements also not always reflected in "major initiatives" that can be monitored and measured

Many small "minor initiatives" that fly under the radar can also lead to performance gains

Incentivized environment can promote performance gains in myriad ways that are not always easy to identify and/or measure

Could MRP Results Have Been Obtained Under COSR? (Con't)

- "Outcome-based incentives encourage innovation by the utility, as opposed to merely conforming to plans approved or ordered by the Commission. Several parties commented that utilities should simply be ordered to implement specific tasks, with no need for incentives. Other parties argued that utilities should not be rewarded merely for performing what is expected of them. These arguments assume that regulators are in the best position to know precisely what actions are needed to achieve policy outcomes. In fact, the optimal role of regulators is not to dictate program terms but rather to set policy and ensure that results are just and reasonable. A construct in which regulators presume foreknowledge of how innovation must occur is antithetical to (reforming the energy vision). Outcome-based incentives will allow utilities to determine the most effective strategy to achieve policy objectives..."

New York Public Service Commission, May 19, 2016, Case-14-M-0101, p. 62

Conclusion

An MRP is a rule-based approach to regulation explicitly designed to create stronger performance incentives than COSR

MRPs have been embraced worldwide, implemented multiple times in several North American jurisdictions, and are gaining more attention in other jurisdictions

Well-designed MRPs can create win-win outcomes, although demonstrating that the same results could not have been obtained under COSR is extremely difficult

Thank You!

Any remaining questions? Please contact:

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Appendix: MRP Experience Selected Jurisdictions

Great deal of PBR and MRP experience throughout North America and the world

Brief examination of the MRP plans approved in three relevant, North American jurisdictions that have approved multiple PBR applications

- Alberta
- Ontario
- Massachusetts

MRP Experience (Con't)

Other jurisdictions that could be of interest in BC

Multiple MRP/PBR Applications

- Quebec
- California

"Utility of the Future" and PBR

- Hawaii
- Rhode Island
- Minnesota

https://www.forbes.com/sites/energyinnovation/2018/05/07/americas-utility-of-the-future-forms-around-performance-based-regulation/#408af2bb2bb2

MRP Experience: Alberta

MRP Decision for gas and electric utilities in province in 2012

“Inflation minus X” formula adjusts allowed rates for five years

“the X factor, combined with the I (inflation) factor, is designed to mirror the pressures of competitive market forces” (Par. 253, Decision 2012-237)

Inflation factor was a weighted average of the change in Alberta Average Weekly Earnings (55%) and Alberta CPI (45%)

MRP Experience: Alberta (Con't)

The X factor was 1.16% with two components

- Industry "total factor" productivity trend of 0.96%, based on U.S. electricity distribution data (*i.e.* distribution operations of 72 U.S. electric utilities, for 1972-2009 period)
- Productivity stretch factor of 0.2%

The Commission found there was no need for productivity and input price differentials in X factor

Companies could also request "capital tracker" treatment for certain capital costs

MRP Experience: Alberta (Con't)

MRP plan updated in 2016 for 2018-2022 period

Inflation factor unchanged, but X factor reduced to 0.3%

Biggest change was capital cost treatment

- Capital tracker treatment still allowed for "Type I" capital that is generally outside management control, highly variable, and cannot be forecast with confidence
- "K-bar" treatment for all other, business as usual capital
  - K-bar amount of capital funding also determined by formula
  - Utilities expected to manage capital spending within the K-bar envelope

MRP Experience: Ontario

Extensive MRP experience in Ontario

I. Initial MRP Plans

- All electricity distributors in Province 2000-2002
- Enbridge Consumers Gas 2000-2002
- Union Gas 2001-2003

II. Natural Gas Forum 2004-2005

III. More Recent MRP Plans

- "Second Generation" IR electricity distribution 2007-2010
- Gas distribution incentive regulation
  - Enbridge Gas Distribution 2008-2013
  - Union Gas 2008-2013
- "Third Generation" IR electricity distribution 2009-2014
- "Fourth Generation" IR electricity distribution 2014-2020
- Amalco Merger 2019-2024

MRP Experience: Ontario (Con't)

Highlights of Ontario MRP Experience

- Initial MRP plans (2000-2003) not successful, sometimes for factors beyond company or OEB control
- The Natural Gas Forum (NGF) was a pivotal event that addressed whether PBR/IR should remain part of the ratemaking framework
- Full range of parties participated and offered comments
- Outcome of NGF was the OEB affirmed its commitment to PBR/IR
- Number of new MRPs subsequently implemented for both gas and electric utilities

Highlights Ontario MRP Experience (Con't)

The Ontario Energy Board found that

"…a multi-year incentive regulation (IR) plan can be developed that will meet its (the Board's) criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment…The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan."1

Natural Gas Regulation in Ontario: A Renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum, March 20, 2005 (RP-2004-0213), p. 22

After NGF, number of MRP plans approved for both gas and electric utilities in the province

Highlights Ontario MRP Experience (Con't)

- Electricity Distribution MRPs are implemented province-wide and applies to nearly 70 distribution utilities

- Both "Third Gen" and "Fourth Gen" IR had extensive working group meetings at outset of proceedings

- PEG and OEB staff proposed terms of both Third Gen and Fourth Gen IR; two different coalitions of utilities, as well as several customer groups, responded and most provided counter-proposals

  >> Alberta later followed a similar model

- Only two major gas distributors (recently merged); both of their 2008 proposals resulted from settlements with staff and interveners

Highlights Ontario MRP Experience (Con't)

- Third Gen IR included an "incremental capital module" option for distributors that need more capital funding

- Distributors allowed to file incremental capital applications provided they met specified conditions

- The module was designed to eliminate "double counting" of incremental capital spending, through both the module and the "I-X" indexing mechanism

- Some controversies with incremental capital module applications

Highlights Ontario MRP Experience (Con't)

- Before Fourth Gen IR, the Board announced a "Renewed Regulatory Framework" that allowed utilities to choose between three IR options
    - Price Cap IR: basically the same structure as Third Gen IR
    - Annual IR: more light-handed version of Third Gen IR
    - Custom IR: Company-specific application, usually forward-looking, multi-year cost of service application with benchmarking and incentive provisions
- Both the incremental capital module and the three options in the Renewed Regulatory Framework were largely motivated by the diversity in conditions and needs among the approximately 70 electricity distributors regulated by the OEB

MRP Experience: Massachusetts

- Department of Public Utilities (DPU) undertook comprehensive review of the merits of incentive regulation and conventional cost of service regulation (COSR) in DPU 94-158
  - A few targeted incentive mechanisms before that time
  - But overwhelmingly used COSR
- DPU found "…it seems unlikely that COS/ROR regulation, with its lack of flexibility and frequent, lengthy rate procedures, will continue to bring the benefits to consumers that it has in the past."

MRP Experience: Massachusetts (Con’t)

Compared with COSR, the DPU found incentive regulation potentially offered five broad classes of benefits

1. Improved productive efficiency (*i.e.* cost control)
2. Improved allocative efficiency (input mix)
3. Improved dynamic efficiency (*e.g.* reorganization, long-run initiatives)
4. Facilitate new services
5. Lower administrative (*e.g.* regulatory) costs

MRP Experience: Massachusetts (Con't)

Fundamental rationale for incentive regulation:

> "(b)y giving utilities a financial stake in improved efficiency and a greater share of any of the cost savings that result, incentive regulation can create a positive incentive over COS/ROR regulation that can simultaneously deliver service to customers at lower prices, and encourage innovative services, thereby benefiting customers and firms alike."

MRP Experience: Massachusetts (Con't)

Large number of MRP Plans for Energy Utilities

1. Boston Gas – Initial Plan	1996
2. Massachusetts Electric/National Grid (merger)	1999
3. Generic Service Quality proceeding	**2000**
4. Berkshire Gas	2002
5. Boston Gas – Update	2003
6. Blackstone Gas	2004
7. Nstar Electric	2005
8. Bay State Gas	2005
9. Generic Revenue Decoupling proceeding	**2007-08**
10. Bay State Gas – Decoupling (proposed)	2009
11. Boston Gas – Update II (proposed)	2010
12. Generic Service Quality – update	**2012-13**
13. Eversource (Nstar)	2017
14. National Grid (proposed)	November 2018

Highlights of Massachusetts MRP Experience

- X Factor determined as the sum of a "Productivity Differential" and an "Input Price Differential"
  - Appropriate in principle when there is a single, economy-wide inflation measure (unlike Alberta or BC)
  - Usually leads to lower X factors, but also less allowed price adjustment through the inflation measure
- D.P.U. often conducts "generic proceedings" on large policy issues that leads to general policy positions that apply statewide
- After general policy established, each company puts forward its own regulatory proposals to comply with policy objectives, rather than having a single jurisdiction-wide approach
  - Incentive Regulation
  - Revenue Decoupling

Highlights of Massachusetts MRP Experience (Con't)

- State-wide generic decoupling proceeding put MRPs on hiatus for several years
  - D.P.U. found that revenue decoupling and MRPs could in principle be integrated and work together to achieve distinct objectives
  - However, D.P.U. also found that every decoupling proposal must begin with new "cast off rates," determined through a general rate case
  - Some companies subject to MRPs at the time, attempted to retain MRP while complying with this rule
  - D.P.U. ruled that utilities could not have cost of service based rate changes (necessary before revenue decoupling to take place) at the same time that there are MRP-based rate changes
  - This led some PBR plans to be terminated; other utilities let their MRPs run their course before filing decoupling proposals

Highlights of Massachusetts MRP Experience (Con't)

However, there has been a resurgence of interest in MRPs in MA in the last couple years

D.P.U. approved new MRP for Eversource (parent company of NSTAR and Western Massachusetts Electric) in 2017

National Grid (parent company of Massachusetts Electric and Nantucket Electric) filed a MRP proposal on November 15, 2018

Final decision on National Grid proposal expected in summer 2019

Overview of MRP Experience

Jurisdictions adopting MRPs have generally stuck with it

Experience in Ontario and Massachusetts has been disrupted to deal with other policy challenges, and some unexpected outcomes, but regulators and regulated companies have retained commitment to MRPs

MRPs have increasingly adopted provisions to allow for incremental capital spending needs for some utilities

Alberta's K-bar approach establishes relatively strong incentives to pursue incremental capital spending efficiently

Increasing interest in PBR in "utility of the future" applications

Stakeholder Consultation

Efficiency Benchmarking Study and Next Generation PBR

April 2017

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Agenda

- Review of directives from PBR Decision
- Terms and parameters of benchmarking study (with some examples)
- Benchmarking study – selection of consultant
- A performance review of current PBR
- Review of other jurisdictions "next gen" PBRs
- Discussion of preferences for modifications to current PBR or adoption of another framework (scope of next PBR proceeding)
- Discussion of options for rebasing
- Other?

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Review of directives from 2014 PBR Decision

A benchmarking study would provide the Commission with information on the utilities' efficiency relative to other utilities. While there is no such study available at this time, the Panel considers that it would be useful to have one completed ***prior to the application for the next phase of the PBR****.* ***Accordingly, the Panel directs FEI and FBC to each prepare a benchmarking study to be completed no later than December 31, 2018.***

In order to avoid a clash of methodologies as was experienced in this Proceeding, the ***Panel directs that Fortis consult with the parties to this proceeding, including Commission staff, prior to engaging a mutually acceptable consultant to conduct the benchmarking study****. As a result of this consultation, the Panel expects that agreement be reach on the broad terms and parameters of the study.* ***Fortis is directed to report the results of this consultation to the Commission prior to starting the study.***

FEI 2014 PBR Decision, p. 82

Terms and parameters of benchmarking study

- Scope of benchmarking study:
  - Benchmarking studies are often limited to operational expenditures.
  - Companies' historical trend analysis vs. comparison with other utilities

- Benchmarking approach:
  - Unit cost benchmarking

Some examples are as follows:

- Elenchus Research; "Benchmarking study of Canadian natural gas distribution utilities" on behalf of Terasen Gas; June 2009
- PWC; "Comparative analysis of key performance indicators" on behalf of BC Gas, November 1991

Other jurisdictions:

- Hydro-Quebec; "Benchmarking and the distributor's efficiency", August 2005

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Analysis of current PBR (Opex)

2014-2019 PBR Performance

The companies have been able to manage their costs below the formula levels and share the benefits with ratepayers; O&M per customer is generally declining.

FEI	2010	2011	2012	2013	2014	2015	2016
O&M (Nominal $millions)	$ 237.1	$ 245.9	$ 254.2	$ 264.9	$ 257.8	$ 260.0	$ 259.0
O&M (Real $millions)	$ 259.1	$ 263.8	$ 268.0	$ 276.6	$ 266.9	$ 262.1	$ 259.0
O&M Per Customer (Nominal $)	$ 257	$ 264	$ 271	$ 280	$ 269	$ 268	$ 261
O&M Per Customer (Real $)	$ 281	$ 283	$ 285	$ 292	$ 278	$ 271	$ 261

FBC	2010	2011	2012	2013	2014	2015	2016
O&M (Nominal $millions)	$ 50.9	$ 53.1	$ 53.5	$ 56.7	$ 59.7	$ 57.8	$ 55.6
O&M (Real $millions)	$ 55.6	$ 56.9	$ 56.4	$ 59.2	$ 61.8	$ 58.2	$ 55.6
O&M Per Customer (Nominal $)	$ 402	$ 415	$ 418	$ 443	$ 461	$ 440	$ 419
O&M Per Customer (Real $)	$ 439	$ 446	$ 441	$ 462	$ 478	$ 444	$ 419

* 2016 numbers are preliminary

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Analysis of current PBR (Capex-FEI)

2014-2019 PBR Performance

Growth capital: From 2014 to 2016 the FEI's actual growth Capex has been above formula by $34 million

Other capital: From 2014 to 2016 the FEI's actual other capital amount has been above formula by $6 million

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Growth	24.231	21.478	2.753	45.776	28.480	17.296	47.500	33.262	14.238
Other	100.168	98.343	1.825	107.803	110.901	- 3.098	113.096	112.053	1.043

A combination of factors discussed in the 2017 Annual Review has led to a mismatch between formula and actual amounts for capital expenditures.

* 2016 actuals are preliminary

Analysis of current PBR (Capex-FBC)

2014-2019 PBR Performance

From 2014 to 2016 FBC's actual Capex has been above formula by $6.1 million

	2014			2015			2016		
	Actual	Formula	Variance	Actual	Formula	Variance	Actual	Formula	Variance
Formula Capex	42.982	42.193	0.789	44.790	42.384	2.406	45.838	42.874	2.964
Pension/OPEB	6.396	6.396	-	4.253	4.253	-	3.674	3.674	-
Total	49.378	48.589	0.789	49.043	46.637	2.406	49.512	46.548	2.964
			1.62%			*5.16%*			*6.37%*

The gap between Capex formula amounts and actual amounts is smaller for FBC, however some of the same reasons have led to a mismatch between formula and actual amounts for capital expenditures. FBC's stretch factor is 0.1 percent lower than FEI's stretch factor.

* 2016 actuals are preliminary

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Review of PBR plans in other jurisdictions

Alberta Electric (2018-2022)	Price cap; Rates $_t$ = Rates $_{t-1}$ * (1 + I – X) I = 55%*Alberta AWE + 45% Alberta CPI; X-factor: 0.3%
Alberta Gas utilities (2018-2022)	Revenue per customer cap; Revenue per customer t = Revenue per customer$_{t-1}$ * (1 + I – X); I = 55%*Alberta AWE + 45% Alberta CPI; X=0.3%
Ontario 4th generation Incentive regulation (2014-2018)	Price cap, Rates t = Rates t-1 * (1 + I – X); I = 30%*Ontario AWE + 70% Canada GDPPI-FDD; X-factor = 0% + 6 cohorts of stretch factor (0%, 0.15%, 0.30%, 0.45%, and 0.60%) which may change annually depending on the performance of the distributor
Union Gas (2014-2018)	PCI = (I-X) + Y + Z + Normalized Average Consumption (NAC); I = Canada GDPPI-FDD; Productivity: Reduction in 2013 approved revenue requirement by an upfront productivity commitment of $4.5 million and X-factor = 40% of inflation

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Review of PBR plans in other jurisdictions

Hydro Quebec (2018-2021)	$Rt = R_{t-1} * (1+ I - X + G)$; G: growth in number of customers I-factor : composite factor of Quebec wage growth and Quebec CPI
Enbridge (2014-2018)	No formula, Custom made PBR given extraordinary capital requirement (capital for 2014-2018 is 28% above its core capital requirement) <u>O&M</u>: Forecast for 2014 and increased by 1% for the subsequent years (excluding customer care, DSM and Pension and OPEB) <u>Capital</u>: forecasted for 2014-2016, 2017 and 2018 capital was not forecasted; Enbridge agreed to use the 2016 forecast (excluding the asset management project) for 2017 and 2018 with no change.

Should FEI's and/or FBC's new generation PBR follow the same hybrid revenue cap or an alternative approach should be adopted? Should the scope of next generation review be limited?

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Rebasing options

Options for rebasing

Should the new Generation PBR start in 2020?
If so should the rebasing be based on 2019 cost of service forward-looking test year separated from PBR formula?

Or should there be a one or two year cost of service bridge year? If so then should the rebasing be based on 2020 or 2021 forward-looking cost of service approach or an alternative rebasing approach?

Other

- In your view, what are the "must haves" for an extension or another PBR plan?

- Any comments/suggestions regarding the benchmarking methodology or the consultant selection process?

Appendix C4

MRP SUPPORTING PAPERS

Appendix C4-1

MAKHOLM, *THE RISE AND DECLINE OF THE X FACTOR IN PERFORMANCE-BASED ELECTRICITY REGULATION*, THE ELECTRICITY JOURNAL 31 (2018) 38-43

The Electricity Journal 31 (2018) 38–43

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The rise and decline of the *X factor* in performance-based electricity regulation

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Keyword:
Incentive regulation

ABSTRACT

'RPI minus *X*' incentive regulation—a 1990s UK import—never resonated beyond a handful of states and provinces for controlling regulated electric utility prices. As the North American electricity distribution industry continues to evolve toward a platform for facilitating a more decentralized and carbon-free energy supply, RPI minus *X* will face increasing difficulties in dealing objectively with the sharply rising investment costs represented by that new role.

Twice in the past year, The Electricity Journal published articles focusing on the *X factor* by respected economists who document their long experience in the RPI minus *X* form of performance-based regulation (PBR) and articulate their hope that such index-based PBR "can be unleashed to the benefit of all key stakeholder groups in the electricity industry."[1] With a history of dealing with the *X factor* that is at least as long, I do not envisage any near-term expansion of that particular form of rate control for the North American electricity industry.[2]

To explain why, I take three perspectives on RPI minus *X* regulation: (1) its origin as a UK import and only limited subsequent application in North America, (2) its difficulty in objectively integrating recent and rapid changes in the role of electricity distributors and the sharply rising investments faced by the sector, and (3) the movement of "incentive regulation" in electricity away from a generalized competitive ideal and toward more targeted projects involving a greener and more decentralized energy supply.

1. The origin of RPI minus *X* regulation

The RPI minus *X* form of incentive regulation model is a UK import, implemented there to speed that country's rapid privatization in the 1980s under Margaret Thatcher's government. Its allure to economists in the UK lay in its promise to bypass perceived "cost-plus" inefficiencies and overcapitalization of "rate of return" regulation in North America.[3] The characterization of such U.S. regulatory inefficiencies in the choices available to the UK government was always inaccurate—abstracting from the wider legal, accounting and administrative institutions developed over the first half of the 20th century that made the North American regulation model effective.[4] But that implication had a useful purpose in the UK at that time: it helped Thatcher's government avoid the need to create accounting, administrative, and due process rules that would necessarily have slowed down rapid privatization (which is what the Thatcher government demanded).[5]

As originally conceived in 1983 by UK economist Stephen Littlechild, the "*X*" in the RPI minus *X* framework would be part of a "package of measures" to be taken on by investors in the license responsibilities offered through the privatization of UK public enterprises (starting with Heathrow Airport and British Telecom).[6] In that way, the government had wide freedom in setting *X*, as any value it took would

[1] Meitzen, M.E., Schoech, P.E., and Weisman, D.L., "The alphabet of PBR in electric power: Why X does not tell the whole story;" *The* Electricity *Journal* 30 (2017) 30-37; "Debunking the mythology of PBR in electric power," *The Electricity Journal* 31 (2018), 39-46, p. 46

[2] The measurement of the *X factor* as it relates to changes industry total factor productivity (TFP) growth was a component of my Ph.D. dissertation. See: Makholm, J.D., "Sources of Total Factor Productivity in the Electric Utility Industry," Ph.D. Dissertation, University of Wisconsin-Madison, May 1986.

[3] Beesley, M.E., and Littlechild, S.C., "The regulation of privatized monopolies in the United Kingdom," *Rand Journal of Economics*, Vol. 20, No. 3., p. 456.

[4] I described those regulatory institutions at some length in this journal in 2016: Makholm, J.D., "The REVolution yields to a more familiar path: New York's Reforming the Energy Vision (REV)," *The Electricity Journal* 29 (2016) 48-55.

[5] See: Makholm, *The Political Economy of Pipelines*, University of Chicago Press, Chicago and London (2012), pp. 57-58. I describe there more fully the politics of rapid UK privatization.

[6] Littlechild, S.C., "Regulation of British Telecommunications' Profitability," London: Department of Industry, (1983).

https://doi.org/10.1016/j.tej.2018.10.008

be folded into the bids for privatized enterprises. In the re-setting of *X* in subsequent rate cases after privatization, Littlechild emphasized the broad peremptory powers of UK regulators that do not translate to North America.[7] Partly for historical reasons and partly because of the more openly political nature of a UK regulatory system that lacks independence from UK executive authority, the ongoing UK implementation of RPI minus *X* turned out to be more difficult and contentious than anticipated. After a governmental retrospective on its perceived failures, the UK partly abandoned that form of regulation in 2013 in favor of another regulatory model labeled "RIIO" (Revenue = Incentives + Innovation + Outputs).[8]

2. The importation ofRPI minus Xto North America

RPI minus *X* regulation crossed to North America in the late 1980s. As a means of injecting some competitive pressures into regulated price setting, it attracted considerable scholarly interest relating to the restructuring of the telecommunications industry (in the wake of the 1982 breakup of AT&T that produced the regional Bell operating companies) and the evident problems of sharply rising real electricity and gas rates.[9] Those Bell operating companies adopted RPI minus *X* to lessen their post-breakup regulatory burdens, and a few U.S. and Canadian electricity and gas utilities in a small number of states and provinces (California, Maine, Massachusetts, Oregon, Ontario, British Columbia and Alberta) conceived that it could lower the burden of frequent rate cases and act as a means of raising their meager 1980s earned returns.[10]

But despite using the same label, RPI minus *X* regulation in North America was always wholly different than its UK forerunner. With far fewer due process and evidentiary requirements, UK regulators could effectively invent an *X factor* value to square current rates with those based on long-term (5- or 10-year) forecasts of costs and volumes in rate re-setting cases. North American regulators, however, are bound by specific statutory provisions regarding due process and the "burden of proof."[11] Thus, the *X factor* in the United States and Canada reflected an index-based method of measuring industry total factor productivity (TFP) growth relative to TFP growth in the economy at large. The empirical measurement of the relative industry TFP growth followed theoretical advances in the economic theory of index numbers coming outof the University of California-Berkeley and the University of Wisconsin-Madison (including my own Ph.D. work). With such techniques for deriving objective productivity indexes suitable for regulated industries, an *X factor* rooted in relative industry TFP growth became an integral part of RPI minus *X* cases in the United States and Canada.

3. Why is an *X factor* even necessary?

The theory behind the North American version of the *X factor* looks complicated, with meticulous supporting empirical evidence, including an almost overwhelming assemblage of dense tables and complex computations.[12] But the aim of the exercise is straightforward—to find a reasonable allowance for inflation that can regularize "regulatory lag." The lengthened regulatory lag permits regulated companies to earn returns against a pre-determined trajectory of rate control—driving the firm's incentives. The *X factor* represents those adjustments that may be required to permit published government inflation indexes to work for a price adjustment formula applied to a particular regulated industry. That is the sole purpose of the *X factor*: to adjust published government inflation indexes to fit the needs of a particular regulated industry.

That form of indexed rate control resonated best with the Bell operating companies, which could readily define "baskets" of disparate services (local service, long-distance, messaging, call waiting, etc.) subject to a single weighted-average price cap moving according to the RPI minus *X* index. The industry in the 1990s also was in a period of rapid productivity growth due to new technologies (e.g., electronic switches, digitization, fiber optics). Thus, RPI minus *X* regulation gave telecom regulators tools to lighten regulatory burdens both by specifying average price caps and by permitting regulated prices to move after being set—taking away the need persistently to update individual regulated service rates. The Federal Communications Commission (FCC) issued its "price cap" order with an *X factor* in 1989. California followed with its own price cap decision in 1989, and Massachusetts followed in 1995.[13]

In U.S. telecom regulation, RPI minus *X* was a bridge to deregulation. The local Bell operating companies moved away from *X factors* more than a decade ago and no longer employ the concept for the few regulated services they have left.[14] The FCC revisited the *X factor* after a 15-year hiatus in 2017 for the small portion of business services (perhaps 10%) that remains regulated.[15]

RPI minus *X* regulation did not resonate as well for electric and gas distribution utilities. Companies with a single product (i.e., distribution services) had no telecom-like "basket" of diverse services, no telecom-like rapid technological progress, and no prospect of deregulation. Thus, RPI minus *X* regulation for energy distribution utilities in North America generally worked only to institutionalize a set period of regulatory lag for pricing services that were never foreseen as candidates for deregulation.

4. The search for objectivity in RPI minus *X*

Importing RPI minus *X* regulation to North America required strong emphasis on objectivity, scholarly support, and reproducible empirical analysis. This wider foundation for regulatory decision making not only comes from the greater due process foundation that guides North American regulation generally but also on the nature of North America's contested regulatory proceedings. Those proceedings represent a reasonably formal dispute resolution forum among parties

[7] "…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. … In the U.K., there is less pressure for due process, [and] neither governments nor regulators have given detailed reasons for their decisions on *X*." Littlechild, S.C., "The Regulation of Privatized Utilities in the United Kingdom," *The Rand Journal of Economics*, Vol. 20, No. 3 (1989), p. 461.

[8] See: https://www.ofgem.gov.uk/ofgem-publications/51870/decision-docpdf.

[9] There was a notable "Symposium on Price-Cap Regulation" in the Autumn 1989 issue of *The Rand Journal of Economics* with six papers on the subject, including Littlechild's.

[10] I reported on these 7 jurisdictions' histories of *RPI minus X* regulation in my 2012 report to the Alberta Utilities Commission. See: NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," Feb. 22, 2012, p. 30.

[11] The most straightforward presentation on the subject of the burden of proof in North American ratemaking comes from Leonard Saul Goodman—a Harvard lawyer and long-time consultant to the federal government on the legal elements the process of making rates for utilities and other regulated industries. See: Goodman, L.S., *The Process of Ratemaking*, Public Utilities Reports, Vienna Virginia (1998).

[12] See NERA, "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," Dec. 30, 2010; and NERA, "Update, Reply and PBR Plan Review for AUC Proceeding 566 – Rate Regulation Initiative," Feb. 22, 2012.

[13] See: FCC 95-132, CC *Docket* No. 94-1 "In the Matter of Price Cap Performance Review for Local Exchange Carriers," Appendix D). For California, see decision D.89-10-031; for Massachusetts, see New Eng. Tel. & Tel. Co. dba NYNEX, D.P.U. 94-50, May 12, 1995). NERA assisted with all three efforts.

[14] Tardiff, T.J., Changes in industry structure and technological convergence: implications for competition policy and regulation in telecommunications," *International Economics and Economic Policy* (2007), 4: 109-133.

[15] See Report and Order, FCC 17-43, Adopted April 20, 2017.

with contending interests. While it is widely understood—generally unstated—that objectivity and transparency are of paramount importance when judges and commissions decide such cases, RPI minus *X* brought those issues to the surface most clearly in an important recent case in Alberta. The outcome of that case showcases the challenges facing RPI minus *X* regulation in an era of rapid changes for electricity distributors.

From 2010 to 2012, the Alberta Utilities Commission (AUC) held North America's largest generic proceeding on how to re-implement RPI minus *X* regulation for its electric and gas utilities.[16] Driven by an engaged and energetic chair, Willie Grieve (a former telecommunications attorney with direct experience with RPI minus *X* regulation), virtually all the recognized *X factor* experts in North America participated. I was involved as the independent expert for the AUC.[17]

The AUC confirmed that the *X factor* was all about regulatory lag:

> As NERA emphasized, this concept corresponds to the underlying theory behind [RPI minus *X*] 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.[18]

In its final order in 2012, the AUC accepted my empirical data and computational methods for measuring relative industry TFP growth, from which the AUC derived its common *X factor* for the electric and gas distribution utilities in Alberta. The AUC adopted my recommended methods again in its 2017 *X factor* re-set—as did the Massachusetts Department of Public Utilities (DPU) in 2017 when it revived its own RPI minus *X* method of setting a future path for regulated rates.[19]

The most important element of the AUC's proceeding surrounded its stated search for objectivity, consistency, and transparency in data and methods:

> Because the parameters of the [RPI minus *X*] 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 overstated. In this respect, the Commission observes that having extensively scrutinized and tested NERA's study, the companies were satisfied that NERA's TFP analysis complies with these criteria. The Commission agrees.[20]

Repeatedly in its findings, the AUC turned away from subjective methods or data sources that were not publicly available.

I show in Fig. 1 the result of my TFP growth computations for the AUC 2012 generic proceeding for the years 1971–2009 and add, in lighter bars, the years 2010-2017—which are falling off a veritable cliff. The past seven years show negative TFP growth (as do 9 of the last 10), whereas each of the 15 years ending in 2000 showed positive TFP growth.

Such a trend means that the choice of historical time periods drives the resulting *X factors*. It was an issue that garnered much attention in the AUC proceeding. Ultimately, that Commission decided to use the longest time period available (which I had proposed) against the majority of other parties (who suggested earlier or later sample periods rather than the entire population of possible years). I had given two reasons for the longest period—business cycles and the competitive foundation for the entire concept of RPI minus *X* incentive regulation.

As long-term regulatory commitments drive incentives, effective PBR plans require reliable methods to derive the formula elements for future prices—which in turn depend on the reasonableness and objectivity of the analytical methods and data. Only changes in long-run average cost move equilibrium prices in competitive markets. Short-run changes in productivity—even industry-wide changes in productivity—do not cause firms to enter or leave an industry. The AUC agreed with me 2012—referring both to that competitive standard for productivity-growth-based PBR plans generally and the subjectivity inherent in deviating from the longest period:

> In the Commission's view, NERA's approach of using the longest time period available allows a smoothing out of the effect of variations in economic conditions on the estimate of TFP growth, without engaging in a subjective exercise of picking the start and end point of a business cycle.[21]

In these respects, Fig. 1 presents a problem for any regulator seeking objectivity—for the trend displays neither a business "cycle" for U.S. electricity distributors nor a stable competitive equilibrium. The downward trend in measured productivity growth after 2000 reflects more persistent and permanent changes having to do with the changing nature of electricity distribution services.

5. The changing nature of investments in energy distribution

Many new electricity investments (and other operating costs) deal with activities not related to traditional electricity distribution–leading to inputs without a corresponding increase in output, or a decline in measured productivity growth. An example is advanced metering infrastructure (AMI)—technology only partially adopted in some North American jurisdictions. The percentage of electricity customers with advanced meters has grown from 1 to 2% a decade ago, to more than 40% today. This amounts to a combined utility investment of $15-30 billion for a technology that, if anything, leads to lower utility kWh output. The penetration of AMI is just one of the reasons for the declining TFP growth numbers for U.S. electricity distributors. Investments in a range of grid modernization technologies related to electric vehicle charging, electrical storage, voltage optimization, data management, and cybersecurity have become the norm.

The obvious question prompted by Figs. 1 and 2 is whether the measurement of TFP growth—comparing the growth of physical inputs compared to physical outputs—should switch away from traditional output measures (such as kWh) to a mix of output measures (e.g., numbers of customers, line miles, peak usage, etc.) in addition to kWh. Any jurisdiction using the *X factor* for energy distributors in the future must take into account such a trend—either by choosing a different measure of output or a different period.

In 2017, the FCC examined different time periods for its *X factor* analysis for the remaining regulated business telecommunication services—making its own choice from selected years from the same data set. Table 1 shows their choices—and Table 2 for shows similarly various choices using my data set.[22]

Using comparable methods with only a change in historical time periods, the FCC faced a far less consequential choice than any electricity regulator would. The *X factor* for telecom companies generally rose and fell around a figure of 2% —the number that the FCC ultimately chose. But any electricity regulator would see a sharply declining *X factor* based on a more recent period—a subjective choice of

[16] Alberta had investigated *RPI minus X* in 1999-2000, but the effort was abandoned by the companies and regulator.

[17] See AUC, Decision 2012-237, Sept. 12, 2012.

[18] AUC Decision 2012-237, page 58 (quoting Exhibit 391.02, NERA second report, paragraph 2). See: NERA, "Total Factor Productivity Study for Use in AUC Proceeding 566 – Rate Regulation Initiative," Dec. 30, 2010.

[19] AUC Decision 20414-D01-2016 (Errata), Feb. 6, 2017; Testimony of Mark E. Meitzen, DPU 17-05, Exhibit ES-PBRM-1, Jan. 17, 2017.

[20] AUC, Decision 2012-237, September 2012, pp. 73-4.

[21] AUC Decision 2012-237, pp. 61, 66.

[22] This was the data set used in Alberta and Massachusetts for their *X factor* analyses.

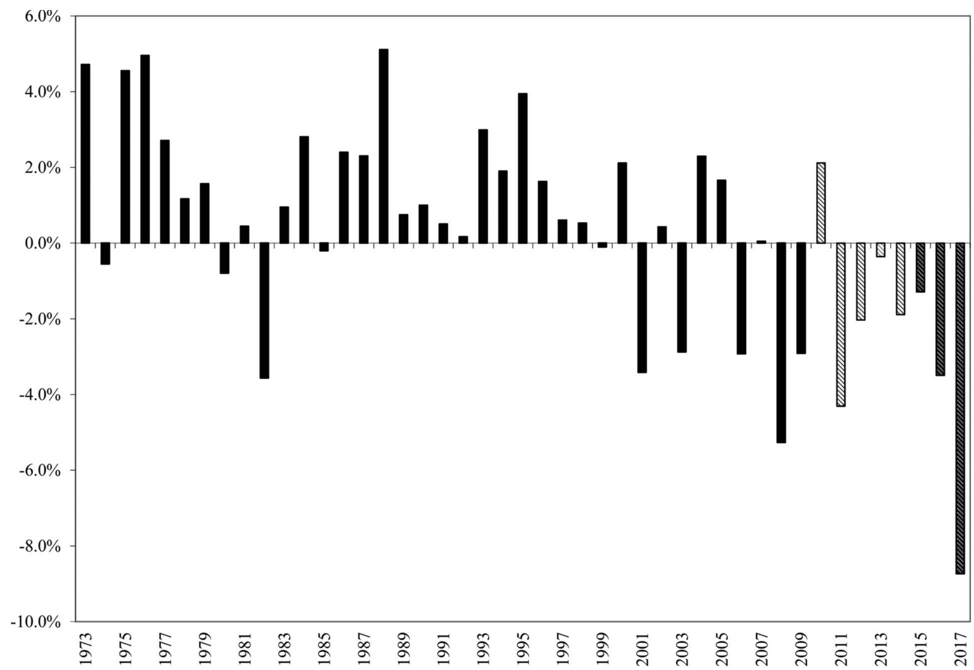

Fig. 1. Average TFP growth, 65 US electricity distributors.1973–2017.
Source: FERC Form 1 and NERA TFP computations

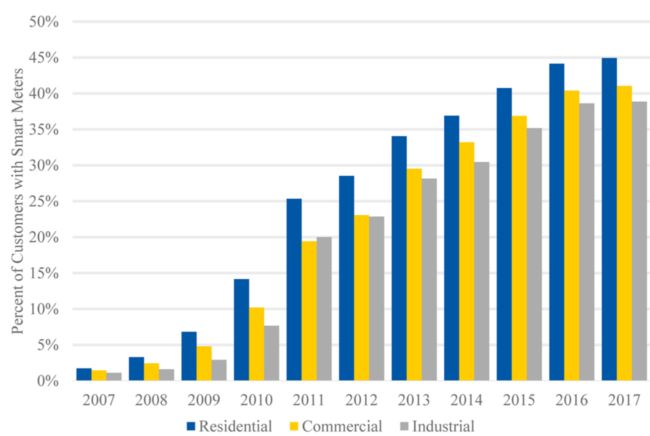

Fig. 2. Advanced metering penetration, US electric utilities, 2007-2017.
Source: EIA Form 861, Years 2007–2017 (early release). NERA Analysis

great consequence for the path of future rates under an electricity distributor *RPI minus X* regime. A long period yields a slightly negative *X factor*, and a more recent period yields a sharply negative *X factor*, with no objective or disinterested scholarly guidepost to choose one period over the other in a contested rate proceeding (Fig 3).

6. Dealing with an industry in change

What do we do with such an unstable *X factor* for electricity distributors? Can we adjust for the changing nature of the electricity distribution business while still computing a reliable *X factor* that promotes lengthened regulatory lag? Can economists use econometric models to discern the source of non-output-producing costs, or use novel measures of distributors' output, to create a reliable *X factor*? My own answer to these question is: probably not—at least not with the spirit of U.S. Supreme Court Justice Louis Brandeis (the main architect of the way we regulate) looking over our shoulders. Let me explain.

When dismissing North American regulation as "cost-plus," the architects of UK regulation overlooked that the North American regulatory model represents an evolution of institutions to promote *orderly action* where the *private interests* of utility investors intersect with the *public interest* at large. Those economists who have written extensively about the origin of the institutions of U.S. regulation recognize that it ultimately had the practical goal of "harmonizing relations between parties who are otherwise in actual or potential conflict…. [with] the purpose of promoting the continuity of relationships by devising specialized governance structures."[23]

Justice Brandeis defined how we harmonize those relations in North America. Using his unique experience as a private lawyer in Boston (dealing with the problems of governing and regulating public service firms in the city in the late 19th and early 20th centuries), he provided the solution both to preserving basic property values and how practically to judge the efficacy and efficiency of the major utility costs without crossing the line into the duties of utility management. His aim—taking decades to achieve—was a manner of regulation that would be "certain and stable" and that would avoid "shifting and treacherous" rate controversies.[24]

In that respect, Fig. 1 represents a problem. It depicts an industry with rapidly changing costs and regulatory responsibilities vis-à-vis the traditional measures of industry output coming from disinterested scholarly analysis (including mine). But the FERC Form 1 data underlying that figure, as useful as it is for reliably documenting utility property and costs for ratemaking, does not provide an objective way to quantify such rapid changes in measured productivity growth in contested rate proceedings. Individual utilities have countless idiosyncrasies, not tracked by Form 1 data, that no industry-wide *X factor* analysis can capture. And while the field of econometrics has developed

[23] Williamson, O.E., *The Economic Institutions of Capitalism*, Free Press, New York (1985), p. 3.

[24] "The adoption of the amount prudently invested as the rate base and the amount of the capital charge as the measure of the rate of return would give definiteness to these two factors involved in rate controversies which are now shifting and treacherous, and which render the proceedings peculiarly burdensome and largely futile. Such measures offer a basis for decision which is certain and stable. The rate base would be ascertained as a fact, not determined as matter of opinion." Southwestern Bell Tel. Co. v. Public Svc. Comm'n, 262 U.S. 276 (1923).

Table 1
Reported *X factors* at for interstate telecommunication carriers.
Sources: KLEMS (Broadcasting and Telecommunications) data set, Bureau of Economic Analysis & Bureau of Labor Statistics.

Year Range		*Compound Annual Growth Rate*			
		A GDP Growth	B Telecom Price Index Growth	C Telecom Productivity Growth	D = A – (B – C) X-Factor
1	1987 – 2014	2.2%	1.5%	1.3%	2.0%
2	1997 – 2014	2.0%	1.5%	1.9%	2.3%
3	2005 – 2014	1.9%	1.5%	1.6%	2.0%
4	2009 – 2014	1.7%	0.8%	0.8%	1.7%

Table 2
NERA Computed *X factors* for electricity distributors.
Source: Bureau of Economic Analysis, Bureau of Labor Statistics, FERC.

Year Range		*Compound Annual Growth Rate*			
		A GDP Growth	B Electricity Price Index Growth	C Electricity Productivity Growth	D = A – (B – C) X-Factor
1	1973 – 2016	4.1%	5.3%	0.5%	−0.7%
2	1985 – 2016	2.9%	4.3%	0.2%	−1.3%
3	1995 – 2016	2.7%	4.8%	−0.4%	−2.6%
4	2005 – 2016	2.4%	4.9%	−1.6%	−4.1%

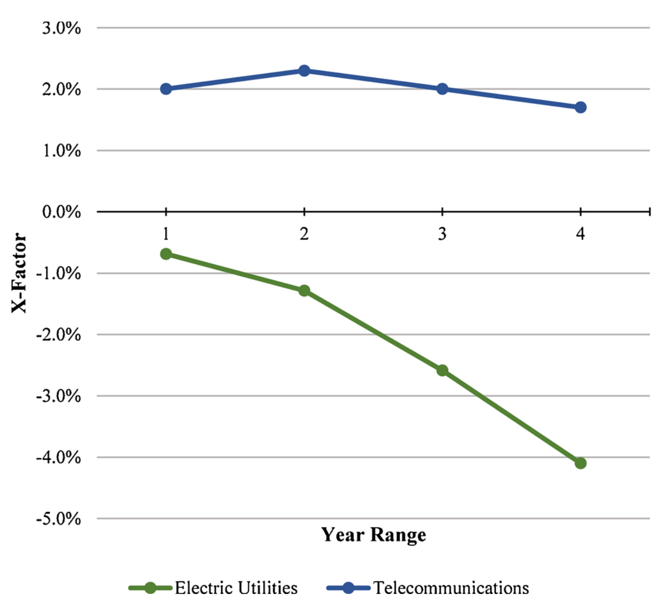

Fig. 3. Changes in TFP growth with alternative year ranges.

methods to deal with some types of idiosyncrasies for the purpose of disinterested scholarly analysis, the AUC, for its part, dismissed tailor-made econometric analyses offered by interested parties in contested rate proceedings as follows:

> …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 judgement of the person conducting the analysis. … 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 purpose of PBR plans.[25]

A recent Australian case of the application of *RPI minus X* regulation provides a telling example where misplaced econometric analysis in contested rate proceedings leads to "shifting and treacherous" controversies that North American regulation has long tended to avoid. In 2015, employing data of questionable applicability to Australia and crudely abstract econometric models, the Australian Energy Regulator (AER) set allowable forecast operating costs for the electricity distributors in New South Wales (Ausgrid, Endeavour and Essential) to be approximately US$4.17 billion less than those utilities requested for 2014-19. The utilities appealed to the Australian Competition Tribunal (the ACT) and won in February 2016 (restoring the $4.17 billion). The AER subsequently appealed to the Full Federal Court, losing in May 2017. In August 2017, the federal government of Malcolm Turnbull introduced legislation (passed in October 2017) to prevent energy companies from appealing AER decisions in the future through the ACT.[26] It was as "shifting and treacherous" a game, involving $4.17 billion in utility revenues with no middle ground, as Justice Brandeis could have imagined a century ago.

7. Where does incentive regulation go?

Fortunately, incentive regulation is a much bigger subject than *RPI minus X*. North American regulators have never been able to compel investors to provide the capital to render public services without a proper profit incentive. In this respect, *all regulation is incentive regulation*. Conflating incentive regulation with *RPI minus X* simply reflects an excessively narrow perspective. The North American regulatory model incentivizes reasonably efficient utility investment and operating behavior while mostly supporting a continuity of successful interactions between investors and the public—two groups that could otherwise be in raging conflict (as in New South Wales).

The era of fast-moving technology and a heightened public policy

[25] AUC Decision 2012-237, pp. 75-76

[26] Australian Competition Tribunal, In the Matter of Applications by Piad, Austrid and Others, 26 Feb 2-16; http://www.judgments.fedcourt.gov.au/judgments/Judgments/fca/full/2017/2017fcafc0080; http://www.esdnews.com.au/limited-merits-review-abolished; https://www.aph.gov.au/Parliamentary_Business/Bills_LEGislation/Bills_Search_Results/Result?bId=r5929

push for more responsive, efficient and green energy utilities have produced a variety of ideas for regulation from many stakeholders, reflected by the large investigations in MIT's "Utility of the Future" projects, New York's REV (Reforming the Energy Vision) initiative and the UK RIIO regulatory regime. All such initiatives include wide-ranging discussions of incentives for modern electric utilities—whether they remain vertically integrated or are fully unbundled from wholesale power markets. For the most part, *RPI minus X* incentive regulation is not part of those discussions. The public policy imperatives of green, customer-responsive, and load-leveled power delivery require more than simply incentivizing competitive cost-reducing behavior (that drives the theory supporting *RPI minus X*). Those new policy imperatives reflect as a desire to change what modern electric utilities do.

Two types of incentive regulation are widely apparent for electricity distributors today: (1) capitalizing expenses (or earing returns on expenses); and (2) earning returns on targeted outcomes. Some examples of each are as follows:

(1) Earning returns or margins on expenses
(2) California authorized its three investor-owned utilities to recover administrative contract costs related to procuring "non-wires alternatives" (NWA) in the utilities' next general rate cases, and to earn a 4% return on the contracted NWA investments.[27]
(3) Illinois is considering allowing utilities to capitalize cloud-based computing solutions, which are currently treated as expenses.[28]
(4) New York authorized utilities to capitalize expenses associated with the procurement of NWA projects and to share in savings associated with the procurement of such projects, authorizing utilities to retain any unspent capital associated with them.[29]
(5) Reward on targeted outcomes
(6) New York authorized utilities to develop "Earnings Adjustment Mechanisms" (EAMs) that would reward utilities for contributing to peak reduction/system efficiency, energy efficiency, customer engagement, improvements in the interconnection process, and lowering cost of clean energy standard (CES).[30]
(7) Rhode Island authorized performance incentives for electric and gas energy efficiency targets. Utilities can earn incentives starting at 75% savings target achievement, and can be earned on a sliding scale basis up to 125% for both gas and electric programs. If the utility achieves the energy efficiency target, shareholders can earn a reward of 5 percent of the program budget.[31]

Incentive regulation pertaining to direct performance measures is also alive and well for new types of technology investments. In 2017 utilities or legislatures in 18 states took action related to electric vehicle (EV) charging infrastructure.[32] Six states—Arizona, California, Massachusetts, Nevada, New York, and Oregon—have energy storage mandates.[33] Utilities in several states have been permitted to invest in innovative pilot projects related to the integration of distributed energy resources (DER). For example, California utilities have been recently authorized to undertake demonstration projects related to DER "integration capacity analysis" and to DER locational net benefits analysis.[34]

8. Conclusion

It would be wrong to be too pessimistic about the future of *RPI minus X* regulation for electricity distributors. That form of rate control is a longstanding part of regulatory practices of the few states and provinces that adopted it years ago to deal with their specific regulatory concerns. They may continue with it for years to come—attempting to find ways to deal with rapidly rising costs that do not contribute to increased kWh sales, more electricity delivery capacity or more customers (the traditional utility output metrics). But in those jurisdictions without such a formula-based method of rate control, incentive regulation for electricity distribution is turning away from the broad competitive model that spurred *RPI minus X* and toward more specific activities in the pursuit of policies to promote greener and more efficient electricity use.

Jeff D. Makholm is a Managing Director at NERA. His work involves many aspects of regulating infrastructure industries. He has testified hundreds of times for electric and gas utilities in many jurisdictions in the U.S. and around the world, on many subjects. He did his Ph.D. in Economics at the University of Wisconsin-Madison on topics relevant to the introduction of *RPI minus X* regulation in North America. His latest book, *The Political Economy of Pipelines: A Century of Comparative Institutional Development*, was published by the University of Chicago Press in 2012.

[27] California Public Utilities Commission, "Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot (Rulemaking 14-10-003)," Dec. 15, 2016.

[28] Illinois Commerce Commission, "Notice of Inquiry Regarding the Regulatory Treatment of Cloud-Based Solutions," April 7, 2017.

[29] New York Department of Public Service, "Staff Whitepaper on Ratemaking and Utility Business Models," Case 14-M-0101, July 28, 2015.

[30] New York Department of Public Service, "Staff Whitepaper on Ratemaking and Utility Business Models," Case 14-M-0101, July 28, 2015.

[31] Rhode Island Public Utilities Commission, "Order," Narragansett Electric Company d/b/a National Grid's 2015-2017 Energy Efficiency and System Reliability Procurement Plan (Docket No. 4522), Dec. 19, 2014.

[32] Bonitz, J., Brutz, H., Buster, S., Carr, A., Lips, B., & Proudlove, A., "50 States of Electric Vehicles: 2017 Annual Review," NC Clean Energy Technology Center, February 2018.

[33] https://www.powermag.com/the-big-picture-energy-storage-mandates/.

[34] California Public Utilities Commission, "Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769," Docket R1408013, opened Aug. 14, 2014.

Appendix C4-2

JURISDICTIONAL COMPARISON

Table of Contents

1. INTRODUCTION

In addition to FortisBC Inc.'s (FBC) and FortisBC Energy Inc.'s (FEI) (collectively, FortisBC) multi-year rate plans (MRPs), various models of MRPs, also known as incentive rate-setting mechanisms (IRM or IR) or performance-based rate-setting (PBR), are currently adopted by a number of natural gas and electric utilities in Alberta, Ontario and Quebec.

This appendix provides a comparison of MRPs' features and related regulators' decisions in these jurisdictions. Specifically Alberta's second generation PBR plans for natural gas and electric distributors, the Ontario Energy Board's (OEB) renewed regulatory framework for Ontario's electric distributors, the Enbridge Gas Distribution (EGD) and Union Gas Amalco incentive rate-setting plan in Ontario, Hydro Quebec Distribution's (HQD) and Hydro Quebec Transmission's (HQT) first generation PBR plans are discussed in the following sections. Unless specifically stated, the various historical plans applied to these utilities in the past are not discussed in this study.

In addition to the review of major Canadian MRPs and in response to the feedback received during the workshops regarding the need for review of alternative incentive mechanism in other North American jurisdictions, this appendix includes an additional section to review alternative incentive frameworks in New York and California.

This study relies on publicly available information, which includes regulatory filings and reports available in the utility regulators' websites. The report outlines the essential features of each reviewed plan.

FortisBC notes that all incentive frameworks presented in this report are designed to promote continuous efficiency focus and/or to achieve targeted outcomes while ensuring that service quality requirements and government policy objectives are met; and to create an efficient regulatory process for the period of the MRP, allowing the Utilities to effectively manage business priorities and increase innovative solutions to the Utilities' challenges. Nevertheless, within these common principles, each jurisdiction has tailored the plans to fit its specific circumstances. This supports the popular belief that there is no one "right" incentive model and that the framework adopted for each utility should be in keeping with their specific circumstances and their history with incentive regulation. In other words, while MRPs in various jurisdictions may share many common features, the overall package is tailored to fit the circumstances of each utility[1].

[1] For instance while all plans include specific mechanisms for treatment of exogenous and/or flow-through costs, the eligibility criteria and type of costs allowed for these special treatments are tailored to fit the specific circumstances of the utilities in each jurisdictions.

2. ALBERTA - 2ND GENERATION PBR PLANS FOR DISTRIBUTION UTILITIES

2.1 BACKGROUND AND DEVELOPMENT

Alberta's first generation five-year PBR plan expired on December 31, 2017. The first generation PBR plan approved by the Alberta Utilities Commission (AUC) for electric utilities was in the form of a price cap formula while the natural gas utilities adopted a revenue-per-customer cap model. The other features of both plans were mainly similar for both electric and natural gas utilities. The Utilities' approved 2012 distribution rates based on the mid-year rate base convention without adjustments were used as the going-in rates in the PBR formulas. The AUC also recognized that it may be necessary to treat certain capital expenditures outside the I-X mechanism. Therefore a K-Factor (also known as the capital tracker mechanism) was approved to satisfy utilities' incremental capital funding needs. The capital tracker mechanism used an accounting test to determine how much capital could be treated outside the formula in each year.

In May 2015, AUC issued Bulletin 2015-10 indicating its intention to proceed with the next generation PBR regulatory regime for the distribution utilities and initiated a generic proceeding to establish parameters for the next generation PBR plans, inviting parties to comment on the proceeding's scope. Following submissions from various parties, the AUC issued a final issues list identifying the scope of the proceeding on August 21, 2015. Based on the finalized issues list, the scope of the second generation PBR proceeding was mainly limited to three items: (i) rebasing and going-in rates, (ii) X-factor value update and (iii) capital tracker mechanism.

The AUC further determined that the rest of the first generation PBR plan parameters would remain unchanged for the 2018-2022 PBR plans. The table below provides a summary of first generation PBR plans' parameters that continue to be included in AUC's second generation PBR plans.

Table A:C4-2-1: The Elements of 2013-2017 PBR Plans Extended to 2nd Generation PBR Plans

Item	Alberta Electric Utilities	Alberta Natural Gas Utilities
Term	5 years (2018-2022)	
Type	Price cap	Revenue per customer cap
Formula	$\text{Rates}_t = \text{Rates}_{t-1} * (1 + I – X)$	$\text{Revenue per customer}_t = \text{Revenue per customer}_{t-1} * (1 + I – X)$
I-factor	55%*Alberta AWE + 45% Alberta CPI	
ESM	Not available	
ECM	Yes, ROE bonus up to 50 bps for 2 years after the end of the term	
Y-factor	Yes, foreseeable and outside management control	

Item	Alberta Electric Utilities	Alberta Natural Gas Utilities
Z-factor	Yes, unforeseen, outside management control, materiality threshold: dollar value of a 40 bps change in ROE on an after tax basis	
Re-opener	Yes, Materiality threshold: 500 bps in a single year, or 300 bps above or below the approved ROE for two consecutive years.	
SQI	No change, Reporting requirements under Rule No.2, No automatic penalties	

As indicated, plans' term, formula types, inflation factor (I-factor), the no earnings sharing mechanism (ESM) policy, efficiency carry-over mechanism (ECM), the Z and Y factor treatments, the re-opener provisions as well as the service quality indicators (SQIs) were the items from the first generation PBR that were carried forward to be applied in the second generation PBR plans. In the following section each of these elements is briefly discussed.

2.2 MAIN FEATURES OF AUC'S 1ST GENERATION PBR PLANS EXTENDED TO 2ND GENERATION PBR

Term

The five year term is maintained. The second generation PBR plans will be in place for the 2018 to 2022 period.

PBR Formula

The AUC will continue to employ a price cap for electric distribution utilities (ATCO Electric, ENMAX, EPCOR and Fortis Alberta) and a revenue-per-customer cap for natural gas distribution utilities (AltaGas and ATCO Gas).

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. In contrast, 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.

Inflation factor

The inflation factor is in the form of a composite inflation factor comprised of labour and non-labour components and is calculated based on historic actual changes rather than forecasts. The Alberta's Average Weekly Earnings (Alberta AWE) is used as the labour inflation index and Alberta's Consumer Price Index as the non-labour inflation index (Alberta CPI). The weighting of the factors approved in Decision 2012-237 will continue to be applied in the second generation PBR plans.

Z-Factor treatment

The Z-factor is 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. The following five criteria, of which all must be satisfied, approved in Decision 2012-237 will continue to be adopted by the AUC in determining eligibility 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. The materiality threshold is set 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.
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 must be unforeseen.

Y-Factor treatment

In contrast to the Z-factor, Y-Factor is applied to the costs that arise in the normal course of business, but are such that the company has no control over them. A materiality threshold similar to the one approved for Z-factor mechanism is applied to Y-factor treatment.

In addition to the Y factor criteria, the AUC will allow the distribution utilities to recover as Y factor rate adjustments, specific costs incurred at the direction of the AUC and flow-through costs that have been approved for continued flow-through treatment under the distribution utilities' PBR plans. The following types of costs were determined to satisfy the Y factor criteria: AESO[2] flow-through items, farm transmission costs, accounts that are a result of AUC's directions, income tax impacts other than tax rate changes, municipal fees, load balancing deferral accounts, production abandonment costs, weather deferral account (ATCO Gas only).

Earnings sharing mechanism (ESM)

In Decision 2012-237, 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". In line with this decision, there will be no earnings sharing mechanism for the realized returns higher or lower than the approved return on equity in the second generation PBR plans.

[2] Alberta Electric System Operator

Safeguard Mechanisms (Off-ramps / Re-opener mechanism)

Re-opener mechanism serves as a safeguard against unexpected results during the PBR period and allow for the re-evaluation and modification of certain aspects of the PBR plan. The following re-opener criteria approved in decision 2012-237 continue to apply to AUC's second generation PBR plans:

- Material variance between approved and realized ROE[3]: This is defined as +/- 500 bps in any given year and/or 300 bps in any given two consecutive years
- Material contraction or expansion in the service territories or customers: To be determined on a case-by-case basis
- Change in default supply regulation and other substantial changes in circumstance: For circumstances that cannot be dealt with through Z-factor treatment or other mechanisms

In June 2018, AUC initiated a review process for ATCO Electric and ATCO Gas utilities under the re-opener provisions determined in the decision 2012-237 as both utilities passed the materiality thresholds that were determined for triggering the re-opener provisions:

> ATCO Electric and ATCO Gas filed their 2017 Rule 005 filings on May 1, 2018 and May 15, 2018, respectively. Based on the information in these filings, ATCO Electric exceeded the +/-300 basis point threshold for 2016 and 2017, and ATCO Gas exceeded the +/-300 basis point threshold for 2016 and 2017 and the +/-500 basis threshold for 2017[4].

The review process is currently underway.

Efficiency Carry-over Mechanism (ECM)

Similar to the first generation PBR plans, an ROE-based ECM will be used to maintain plans' incentives during the last years of the PBR term. The ECM will be in the form of 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% and would apply for 2 years after the end of the PBR Plan.

Service Quality Indicators (SQIs)

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. AUC will continue to rely on the legislative provisions to address enforcement issues should service quality degrade.

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3 Weather normalized ROE
4 Notice for proceeding 23604.

2.3 *REBASING AND GOING-IN RATES*

The issue of rebasing and the going-in rates was one of the three main topics included in AUC's final issue list. Rebasing was defined by the AUC as "the exercise of re-establishing the linkage between a utility's revenues and costs with the objective of generally realigning revenues and costs in anticipation of, or at the end of, a PBR plan term."[5]

The issue of rebasing in this proceeding took on extra importance for the AUC and other parties. It was argued that some utilities' success in achieving materially higher realized returns[6] over the approved ROE can be partially traced to their approved going-in rates:

> In response to ENMAX, the UCA filed evidence arguing that had ENMAX begun its FBR term with rates sufficient for it to earn its allowed rate of return in 2006, it would not have needed capital trackers to earn its allowed rate of return over the FBR term. The UCA's evidence focused the Commission on the importance of going-in rates. This suggested that to the extent that the earnings of the distribution utilities subject to the 2013-2017 PBR plans exceeded their allowed rate of return, this may have been due, at least in part, to the distribution utilities' going-in rates and not due entirely to capital trackers, as the interveners had suggested. All parties agreed on the need to ensure that the going-in rates are not too high or too low, in the sense that they would be only sufficient for the utility to earn the allowed rate of return. The Commission understands that getting the going-in rates correct is critical to the success of a PBR plan[7]. [Underline added].

For instance, ATCO Gas' going-in rates were based on the approved forecast for O&M-related revenue requirement in 2012 that was significantly higher than actual O&M expenses in 2012, resulting in approximately $20 million of excess annual revenue, which remained with ATCO Gas for six years and partially contributed to an annual average premium of 390 basis points over the approved ROE during the term of the PBR.

2.3.1 Rebasing method to set the new going-in rates

All parties indicated that some form of rebasing is necessary prior to the next generation PBR plans, to realign costs and revenues for the benefit of the distribution utilities and customers. There was however disagreements on the appropriate methodology.

Under the approach advocated by the distributors, rebasing was done by setting the rates in a cost of service proceeding based on forecast cost for either 2017 (the last year of then existing PBR) or 2018 (the first year after the PBR). If 2017 costs were used the distribution utilities would forecast their 2017 costs and revenue requirement, separate from their 2017 PBR rates.

[5] Decision 20414-D01-2016, p.6
[6] For instance, the realized ROEs for ATCO Gas and ATCO Electric utilities during the term of the first generation PBR were averaged around 12.31 percent and 11.50 percent with both utilities triggering the re-opener provisions.
[7] Decision 20414-D01-2016, p.8

This notional 2017 revenue requirement would not be charged to customers but would be used for the sole purpose of establishing the going-in rates for the next generation PBR plan commencing in 2018. Using 2018 for rebasing would have resulted in an intermediate cost of service year between PBR plans.

EPCOR and the interveners advocated for the use of actual costs, to calculate going-in rates for the next generation PBR plans. The recommendations ranged from the use of simple average of actual costs to the use of actual costs for the last year of the PBR.

Ultimately and considering all the evidence and arguments of the parties, the AUC decided to set the going-in rates based on a notional 2017 revenue requirement using actual costs experienced by the utilities during the first generation PBR term with any necessary adjustment to estimate the costs to reflect any anomalies:

> The Commission's focus in setting the 2017 going-in rates for each distribution utility will be on using its judgement to estimate the costs that each distribution utility operating under the incentives of the PBR mechanism, unencumbered by incentives inconsistent with the PBR incentives, would have incurred in 2017. It agrees with those parties who submitted using actual pre-2017 costs to develop a notional 2017 revenue requirement, adjusted as required for anomalies, best reflects expected revenues and costs without the distorting influence of the incentives which arise during the last year of a PBR term[8].

2.3.1.1 Rebasing the O&M expenditures

Various methods were proposed by parties for using actual costs to determine a notional 2017 revenue requirement. These methods included the use of averages, indexing, or a trending analysis of past expenditures.

Considering utilities' realized ROE numbers during the first generation PBR, the AUC decided that the lowest O&M cost year during the first generation PBR term adjusted for inflation and other anomalies specific to that year would yield an appropriate base for the going-in rates. Decision 20414-D01-2016 also stated that AUC was prepared to adjust the 2017 notional revenue requirement estimate obtained by utilizing prior lowest actual O&M expenditures for a particular utility should the distributors or interveners provide evidence demonstrating to the satisfaction of the AUC that specific and identifiable adjustments are required to account for unique existing or anticipated material cost anomalies.

2.3.1.2 Rebasing the Capital expenditures

The capital component of the notional 2017 revenue requirement was divided into capital additions in 2017 that are subject to I-X and those subject to the capital tracker treatment in that

[8] Ibid, p.11

year. The AUC recognized that due to the differentiating characteristics of capital projects, the same rebasing method as the one approved for O&M expenditure may not be reasonable:

> Capital additions are generally in respect of investments in long-lived assets. This fact necessitates reliance on longer trends or patterns of past actual expenditures than when coming up with an estimate of O&M costs[9].

The AUC therefore determined that the non-capital tracker component of the notional 2017 revenue requirement should be based on the average actual capital additions for years of the first generation PBR plans, excluding the last year, converted to 2017 dollars. These capital additions were assumed to be prudent because the costs were subject to the incentive properties of the I-X mechanism. As for the capital tracker component, the capital additions for the utilities were previously approved in prior capital tracker decisions, either on a forecast or true-up basis.

2.3.1.3 Depreciation and other cost of service studies

One benefit of rebasing is that it could allow utilities the opportunity to update relevant cost of service studies such as depreciation studies, pension, shared services and working capital. Fortis Alberta specifically noted that under Alberta's Electric Utilities Act, utilities should be given an opportunity to update depreciation parameters.

The AUC agreed with Fortis Alberta and stated that it will provide the utilities with an opportunity to file a depreciation study if they choose to do so. However, for regulatory efficiency purposes, AUC determined that utilities would be permitted to file their depreciation study only in the first year of the new PBR plan and not as part of rebasing applications and that any subsequent depreciation changes during the next generation PBR plans would be reflected in rates only if they proved to be eligible for Z-factor treatment. The requests for adjustments to going-in rates related to other types of studies were denied.

Pursuant to the AUC's decision to deny the requested adjustments for anomalies, a number of utilities filed for reconsideration of the AUC's decision arguing the hearing panel committed errors of fact, law or jurisdiction and stated that AUC's test for anomaly adjustments is not understandable and impossible to meet. On October 30, 2018 and by decision 23479-D02-2018 the review panel agreed that the applicants have demonstrated the existence of an error of law and a review of the decision with respect to the anomaly adjustment was granted.

2.4 *CAPITAL EXCLUSION MECHANISMS*

Alberta's first generation PBR decision recognized that there were certain circumstances where a utility may require capital funding in addition to the funding generated under the I-X formula and established a capital tracker mechanism which provided for a cost of service application

[9] Ibid, p.13

process, whereby the revenue requirement associated with approved capital projects could be reviewed, approved and collected from rate payers.

Some intervener groups argued that utilities' high earnings during the 2013-2017 PBR plans were due to the capital tracker mechanism and requested that the capital exclusion mechanism to be eliminated or significantly narrowed. While acknowledging interveners' concerns, the AUC did not believe that the incremental capital mechanism was the primary reason for utilities' higher earnings (as mentioned earlier, in the AUC's judgement the 2012 going-in rates were a major reason for utilities' higher returns)[10]. As a result, the Decision 20414-D01-2016 confirmed the need for an incremental capital funding that is responsive to the specific needs of each utility. However, AUC determined that the incremental capital should be divided into two categories: Type one capital and Type two capital. Each of the two categories is described in sections below.

2.4.1 Type I Capital (K-Factor)

Type one (Type I) capital is a type of capital that may not be eligible for Z-Factor treatment but is not a type of capital that utilities have deployed in the past. These types of capital additions might include capital additions required by new government programs not previously experienced but would not include types of expenditures required by governments in the normal course of expectations. The following eligibility criteria were determined to be appropriate for Type I capital:

- The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base.
- The project must be required by a third party.

The Type I capital tracker mechanism in the second generation PBR plans will continue to rely on the accounting test similar to the one utilized by the utilities during the 2013-2017 PBR plans to determine the amount of K factor funding.

2.4.2 Type II Capital (K-Bar)

At its core, the development of Type two (Type II) capital involves the idea of providing each utility with a predetermined amount of incremental capital funding. The utilities then would be expected to manage their capital programs within the capital funding constraints of the Type II capital amounts provided. In the AUC's opinion, this approach would increase utilities' flexibility in managing their capital needs and reduce regulatory burden that existed in the first generation PBR period for the annual capital tracker forecast, approval and true-up mechanism.

The K-Bar approach and formulas were initially approved in the AUC's Decision 20414-D01-2016 (Errata). However, while reviewing utilities' compliance filings, the AUC provided a

[10] Ibid, p.57

significant revision to the K-Bar capital funding mechanism initially approved. Both the initial decision and the compliance filing decision are discussed below.

2.4.2.1 AUC's Decision 20414-D01-2016

AUC's 2016 decision for K-bar capital amount determination consisted of two components: the 2018 base K-Bar amount and the indexing formula for subsequent years.

Under this approach, an initial amount, referred to as the base K-Bar would be established as the incremental capital funding for all Type II capital for the first year of upcoming PBR (year 2018). The base K-Bar is set using an accounting test similar to the accounting test used for capital tracker applications but applied only to Type 2 capital projects and programs. This involves calculating the amount of capital-related revenue generated under I-X and comparing it to the total capital-related revenue required, calculated using the allowed rate of return on the capital investments approved by the AUC. The difference between these two amounts is the amount of incremental capital funding that is necessary.

For the subsequent years the following indexing formula was approved:

$\text{K-bar}_t = \text{K-bar}_{t-1} + \text{base K-bar} \times (1 + (I_t - X)) * (1 + (I_t\text{-}1 - X))\ldots$

K-bar_t = K-bar factor for current year

K-bar_{t-1} = K-bar from the previous year

Base K-bar = 2018 base K-bar

It = inflation factor for current year

I_{t-1} = inflation factor from the previous year

X = productivity factor

$(1 + (I_{t-1} - X))\ \ldots = (1 + (I_t - X))$ multipliers for all previous years

2.4.2.2 AUC's Decision 22394-D01-2018

AUC's Decision 22394-D01-2018 introduced a significant revision to the "K-Bar" capital funding mechanism initially approved in Decision 20414-D01-2016 (Errata). The most significant change to the "K-Bar" mechanism related to the removal of the indexing formula inherent in the original model (refer to the formula provided in previous section). This function provided escalation of incremental capital funding based on a base K-Bar amount that was to be compounded annually. In the compliance filing decision, the AUC elected to abandon the compounding aspects of K-Bar, in favour of an annual accounting test to be performed during each year of the upcoming PBR term.

2.5 X-FACTOR DETERMINATION

In the 2012 PBR decision, the AUC used the services of NERA for TFP analysis. NERA's analysis involved 72 U.S. electric and combination of electric and gas utilities over the period of 1972 to 2009. The approved TFP value of +0.96 percent was obtained as the average of 37 annual TFP growth values for 1972-2009 period, where each annual value comprised a weighted average of TFP growth values for the 72 individual firms, with weights based on relative firm size in terms of sales volumes, where these sales were also used as the output measure for the utilities. Although NERA's study was not the only TFP growth study considered in that proceeding, the AUC found the NERA study to be preferable over the studies produced by other experts. The final approved X-Factor of +1.16 percent for both electric and natural gas utilities was determined as the sum of the underlying long-term industry TFP growth value of +0.96 per cent and a judgement-based stretch factor of +0.2 percent.

For the second generation PBR, AUC did not retain its own expert. Instead AUC relied on updated NERA studies produced by the utilities' experts and the TFP study conducted by the interveners' expert to inform its decision. A summary of the TFP growth numbers from these experts as well as the NERA and PEG studies filed in the 2012 proceeding is provided in the Table A:C4-2 below.

Table A:C4-2-2: TFP Study Findings in AUC's 1st and 2nd Generation PBR Proceedings

Study	Output measure	Data period	Number of firms	TFP growth calculation (final)
NERA 2012 (approved by AUC)	Volume	1972-2009	72	+0.96%
Lowry 2012	Number of customers Volume	1996-2009 (NG) 1989-2007 (Elec) using NERA's data	34 72	+1.32% to +1.69% for gas +1.08% to +1.23% for Electric
Brattle 2016	Volume	2000-2014	67	-0.79%
Meitzen 2016	Volume	Average of 2000-2014 and 2005-2014	68-72	-1.11%
Lowry 2016	Number of customers	1997-2014	88 21	+0.43% +0.78%

As can be seen, the productivity growth numbers computed by the experts in the AUC's 2016 PBR proceeding range from -1.11 percent to +0.78 percent with an average of -0.17 percent (or -0.49 percent if the results of Dr. Lowry's sub-sample study that was not considered by the AUC is excluded from the calculation). The above table indicates a declining trend in the productivity growth as the proposed TFP numbers by all experts are below the 2012 AUC approved base productivity growth value. This issue was also highlighted in the AUC's 2016 PBR decision[11]:

[11] AUC Decision 20414-D01-2016, p.156, para 156.

> As shown in Table 1, all final recommendations concerning the TFP growth component of the X factor are lower than, and in some cases much lower than, the TFP growth number of +0.96 per cent adopted by the Commission in Decision 2012-237. Consequently, as noted previously, based on the expert evidence received in this proceeding, the issue before the Commission is not whether the TFP growth component of the current X factor needs to be lowered for the next generation PBR, but rather the extent to which it needs to be lowered.

Referring to the wide range of TFP numbers produced by experts in the proceeding, the AUC stated that in its opinion, there is not one correct TFP growth number and that its decision should be informed by a range of TFP numbers[12]:

> In its argument, the CCA, sponsor of Dr. Lowry's study, recommended selecting one of the specific numerical values of TFP growth put on the record of this proceeding, to "discourage witnesses from filing extreme recommendations in the hopes that the Commission will choose a number in the middle. These statements appear to suggest that there is just one correct TFP growth number and any others that are provided are just distractions. The Commission does not subscribe to this view, and considers it has, in fact, benefitted from examining different TFP growth studies in this proceeding that rely on different assumptions and calculations pertaining to the input and output measures. However, studies must provide information describing all aspects of the study, with considerable detail – including easily reproducible supporting calculations – on the effects, both separately and jointly, of changing each of the assumptions used, where the set of assumptions is widely defined, and includes assumptions with respect to data source selection. In the absence of such complete information, the Commission must take the limited set of information that it does have, and apply its expertise and judgement to the available evidence provided in this proceeding to arrive at a TFP growth value to be used as a component of an X factor for the next generation PBR plans.

Ultimately based on the evidence and considering all the variability caused by different assumptions applied to the TFP studies, the AUC used its judgement to set an X-Factor of +0.3 percent, inclusive of any stretch factor, for both electric and natural gas utilities[13]:

> The Commission has determined an X factor, using its judgement and expertise in weighing the evidence and in taking into account the multitude of considerations set out above, in particular evidence demonstrating that the TFP growth value cannot with certainty be identified as a single number, but rather, in view of the variability resulting from the assumptions employed, must be considered as falling within a reasonable

[12] AUC Decision 20414-D01-2016, P.43, para 163-164.
[13] AUC Decision 20414-D01-2016, P.45, para 169.

> range of values, between -0.79 and +0.75. The Commission finds that a reasonable X factor for the next generation PBR plans for electric and gas distribution utilities in Alberta, inclusive of a stretch factor, will be 0.3 per cent.

3. ONTARIO – INCENTIVE RATE-SETTING FOR ELECTRIC DISTRIBUTORS

3.1 *BACKGROUND AND DEVELOPMENT*

The OEB established a new framework for electricity distribution rate regulation in 2012. This new framework was introduced by an OEB policy document titled "Renewed Regulatory Framework for Electricity (RRF) Distributors: A Performance-Based Approach" which articulates the OEB's goals for an outcomes-based approach to regulation which aligns the interests of customers and utilities. The RRF is intended to elevate utility performance by creating incentives for superior performance.

The OEB has developed a set of rate-setting options to ensure that utilities have sufficient flexibility to adopt a method that best meets their needs. The RRF established three incentive rate-setting methodologies for electricity distributors: Price Cap IR (previously known as 4th Generation IR), Custom IR, and the Annual IR Index. Electricity distributors may choose from any of these three options. There are no eligibility criteria for any of these methods, but the rate application must meet the requirements of the rate-setting option. The OEB further commented on the appropriateness of these IR plans for electric distributors based on their specific circumstances.

The Table A:C4-3 below provides a summary of major differences between each IR plan and their appropriateness for individual utilities depending on their specific circumstances.

Table A:C4-2-3: Incentive Rate-setting Under OEB's Regulatory Framework for Electric Distributors

Item	Price cap IR	Custom IR	Annual IR Index
Most appropriate for	Utilities that anticipate some incremental investment needs during the plan term	Utilities with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures	For utilities with relatively steady investment needs (primarily sustainment)
Going-in rates	Single forward test year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by (I-X) index
Term	5 years (rebasing plus 4 years)	Minimum term of 5 years	No fixed term

Item	Price cap IR	Custom IR	Annual IR Index
Incremental capital	Available under ICM and ACM	Not available (although a number of exceptions exist)	Not available

As can be seen, under the Custom IR option, rates are set for a minimum of five years. The Custom IR option is intended to be customized to fit the specific utility's circumstances. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Under the Annual IR Index approach, rates are subject to the same annual adjustment formula as those under Price Cap IR. Utilities under the Annual IR Index are not required to set base rates periodically using a cost of service process, but they are required to apply the highest stretch factor. Finally, under Price Cap IR methodology, base rates are set through a cost of service process for the first year and the rates for the following four years are adjusted using a formula. Unlike the other two rate options, utilities under Price Cap IR can apply for incremental capital funding during the IR period, subject to meeting the eligibility criteria.

All distributors are required to file a distribution system plan (DSP) when filing a cost of service application for the rebasing of their rates under the Price Cap or a Custom IR application. Distributors using the Annual IR Index method must make a DSP filing within five years of the date of the most recent cost of service proceeding; and are required to do so at five year intervals thereafter. A DSP consolidates documentation of a distributor's asset management process and capital expenditure plan. The capital expenditure plan provides a snapshot of a distributor's capital expenditures over a 10 year period (5 year historical and 5 year forecast).

In the following sections the distinctive features of Custom IR and Price Cap IR plans are discussed in more detail.

3.2 *MAIN FEATURES OF PRICE CAP IR UNDER OEB'S RRF*

3.2.1 Price Cap Formula

Under the OEB's Price Cap IR, the allowed rate of change in the price of regulated services is adjusted by the growth in an inflation factor minus an X-Factor.

The X-Factor value may change from year to year depending on OEB's annual total cost benchmarking results. The benchmarking evaluation in each year will place each electric distributor into an efficiency cohort based on its relative efficiency compared to other electric distributors in Ontario where each cohort is given a specific stretch factor[14]. The following section provides more information regarding the I-Factor in OEB's price cap formula.

3.2.1.1 Inflation Factor

Under the RRF, the OEB concluded that it will be appropriate to adopt a more industry specific inflation factor. The inflation factor is in the form of a composite index that includes a non-labor price element (indexed by GDP-IPI FDD) and a labour price element (indexed by Ontario AWE).

The percent of change in composite inflation index is calculated as the weighted sum of 70% of the annual percentage change in the GDP-IPI FDD; and 30% of the annual percentage change in the AWE for the prior year relative to the data for two years prior.

3.2.2 Z-Factor Treatment

Z-Factor treatment of unforeseen events is available to distributors in all three rate-setting 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 electric 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 A:C4-4 below:

Table A:C4-2-4: 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

3.2.3 Y-Factor Treatment

All three 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.

[14] Currently five efficiency cohorts are used with 0.00%, 0.15%, 0.3%, 0.45% and 0.6% stretch factor values. (sorted from the most efficient to the least efficient)

3.2.4 Safeguard Mechanisms (Off-ramps/ Reopeners)

The OEB's RRF does not include an earnings sharing mechanism. The OEB however recognized that some form of protection against potential unintended consequences of IR plans is required and concluded to incorporate an off-ramp mechanism in all three rate-setting options.

Under the regulatory framework, each rate-setting option 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.

3.2.5 Incremental Capital Mechanisms for Price Cap IR

Utilities operating under Price Cap IR plans may apply for and receive additional capital funding outside the formula using the so-called Advanced Capital Module (ACM) and/or Incremental Capital Module (ICM) mechanisms. This is a major distinguishing feature of Price Cap IRs compared to other two IR options, neither of which includes a mechanism for incremental capital spending allowances.

The main difference between ACM and ICM relates to the issue of timing. Under the ACM approach, the need for incremental capital funding is identified at the time of cost of service filings (as part of the DSP filings). At that time, the need for and prudence of any such requests will be determined. Consequently, largely mathematical calculations of ACM-related matters, such as the determination of the rate riders, will remain part of the streamlined IR applications in subsequent years. The ACM approach was developed to increase regulatory efficiency during the Price Cap IR term and to provide a distributor with the opportunity to smooth out its capital program over the five year period between cost of service applications. On the other hand, the ICM requests are limited to those projects that were not foreseen or sufficiently planned as part of the DSP.

A summary of OEB's capital module policy for both ACM and ICM mechanisms is provided in the Table A:C4-5 below:

Table A:C4-2-5: OEB's Capital Module Policy Under Price Cap IR Plans[15]

Capital Modules	Cost of Service Application	Price Cap IR Year (in which the capital project goes into service)	Next Cost of Service Application
ACM (Advanced Capital Module)	• Identify discrete projects in DSP which may qualify for ACM treatment. • Establish need for and prudence of these projects based on DSP information. • Provide preliminary calculation of materiality threshold based on information in cost of service application.	• Update materiality threshold based on current information to confirm that the project continues to qualify for ACM treatment. • Provide means test calculation and explanation if overearning in last historical actual year. • If costs are less than 30% above what was documented in the DSP, explain differences in cost forecasts from DSP forecast. • Explain any differences in project timing. • If costs are 30% or more above what was documented in the DSP, re-file business cases as new ICM if seeking recovery of incremental costs. • In all cases, explain any significant differences in capital budget forecast from DSP forecast. • Provide incremental revenue requirement calculation and proposed ACM rate riders.	• Review of actual (audited) costs of ACM project. • Explanation for material variances between actual and forecasted costs (and timing, if applicable). • Based on above, the OEB may determine if any over- or under-recovery of ACM rate riders should be refunded to or recovered from ratepayers. • ACM capital assets reflected in new rate base based on January 1 actual NBV.
ICM (Incremental Capital Module)	• Not applicable	• Provide explanation for any ICM that could not have been foreseen or sufficiently planned as part of DSP. • Establish need for and prudence of proposed projects. • Provide materiality threshold calculation. • Provide means test calculation and explanation if overearning in last historical actual year. • Provide incremental revenue requirement calculation and proposed ICM rate riders. • Explain significant differences in capital budget forecast from DSP forecast.	• Same as above

Both ICM and ACM projects must satisfy the eligibility criteria of materiality, need and prudence as set out in the table below.

Table A:C4-2-6: Eligibility Criteria for ICM/ACM Mechanisms

Criteria	Description
Materiality	A capital budget must be deemed to be material, and reflect eligible projects, if it exceeds the OEB-defined materiality threshold. Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount and must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing.
Need	The distributor must pass the Means Test. Amounts must be based on discrete projects, and should be related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived.
Prudence	Distributor's decision to incur the amounts must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

15 EB-2014-0219 (Sep 2014); "Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module", Appendix A

3.2.6 Service Quality Indicators

The RRF includes a comprehensive set of performance outcomes and uses a scorecard approach to effectively organize performance information in a manner that facilitates evaluations and meaningful comparisons. The scorecard design includes four performance areas as presented in Table below.

Table A:C4-2-7: Performance Areas in Electricity Distributor Scorecard[16]

Performance Area	Description	Measures
Customer focus	Services are provided according to identified customer preferences	Includes indicators such as First contact resolution (FCR), Calls answered on time, Appointments met on time, Billing accuracy, Customer satisfaction surveys
Operational effectiveness	Continuous improvement in productivity and cost performance is achieved; utilities deliver on system reliability and quality objectives;	Includes safety (serious incident index, level of compliance with safety regulation, Level of public awareness), system reliability (SAIFI, SAIDI) , asset management (DSP implementation progress) and cost control (cost per km of line and per customer) metrics
Public policy responsiveness	Utilities deliver on obligations mandated by government	Conservation and demand management as well as connection of renewable generation metrics
Financial performance	Financial viability is maintained; savings from operational effectiveness are sustainable	Financial ratios related to utilities' liquidity (current ratio), leverage (total debt to equity ratio) and profitability

[16] OEB Report (March, 2014), EB-2010-0379

3.3 MAIN FEATURES OF CUSTOM IR UNDER OEB'S RRF

The Handbook for Utility Rate Applications provides specific considerations that are required for a custom made IR. A custom IR is by its very nature customized for the specific circumstances of individual utilities and not subject to a common model of doing things. However the test for adequacy of a custom IR application is the extent to which the plan's features proposed by applicant meet certain requirements.

Under the Custom IR plan, a distributor rate trend for the plan term is determined by OEB, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts.

The OEB's utility rate handbook explains that a Custom IR plan is not analogous to a multi-year cost of service plan and that any Custom IR plan requires explicit incentives for efficiency improvements and cost reduction[17]:

> Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast). The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service.

The OEB will use external and internal benchmarking to assess the reasonableness of the applicant's forecasts. The external benchmarking will analyse year-over-year performance against key metrics and/or comparing unit costs (or other measures) against best practice benchmarks amongst a comparator group. An internal benchmarking of applicant's costs is also required to assess continuous improvement by the utility over the time.

Although the custom IR option was part of the RRF for electric distributors, Enbridge Gas Distribution 2014-2018 custom IR, was the first custom made IR approved by OEB. After EGD's proceeding, a number of major electric distributors including Hydro Ottawa, Toronto Hydro and Hydro One applied for custom IR model. A common theme between all of these custom IR plans was that capital expenditure was forecasted, although in some cases the forecast was then used to derive a custom index as stated in the excerpt above. In the following sections, EGD's and Toronto Hydro custom IRs are briefly discussed.

[17] OEB's Handbook for Utility Rate Applications, pp 25-26

3.3.1 Toronto Hydro Custom IR

OEB's decision EB-2014-0116 released in December of 2015 approved a custom IR plan for Toronto Hydro's 2015-2019 revenue requirement[18]. Under Toronto Hydro's approved framework, annual capital expenditures are set based on cost of service forecast however the annual forecast are then used to derive a capital factor that will be used to create a custom price cap index (CPCI) to be applied to distributor's rates. Toronto Hydro's plan also includes an earning sharing mechanism, which will share any earnings above the 100 basis points on a 50:50 basis. The plan's Z-factor and off ramp provisions are similar to the OEB approved framework for its conventional price cap formula. The plan also included a number of deferral accounts such as variance account for externally driven capital and variance account for capital-related revenue requirement to reduce the variance risks for the utility and ratepayers. In the following section, the CPCI formula is defined in more detail.

3.3.1.1 Custom Price Cap Index

The CPCI is an OEB-approved formula that includes annually updated components for inflation and a capital factor. The formula also includes a growth factor and a productivity factor. The CPCI formula is as follows:

$$CPCI = I - X + (Cn - Scap \times I) - g,$$

where:

- I is a composite inflation factor
- X is the expected productivity factor fixed for the duration of the plan
- Cn is the capital factor value updated annually
- Scap is the capital expenditure scaler updated annually
- g is the growth factor in billing determinants set for the term of the plan

The capital factor is the amount by which base rates need to be increased to fund distributor's capital investment needs over the course of the term and is calculated based on the following formula:

> Capital factor = incremental capital related revenue requirement calculated based on distributor's cost of service forecast / total revenue requirement.

With inclusion of capital factor in the CPCI, the utility would receive sufficient funding for all of its capital needs as provided in its approved capital plan. However, the I-X mechanism in the CPCI also provide some level of incremental funding. This means that absent some kind of

[18] Recently, in September of 2018 Toronto Hydro filed an application for its 2020-2024 revenue requirement, which is largely based on the same parameters approved for its 2015-2019 revenue requirement.

adjustment, the capital factor would overfund distributor's capital needs; once through the I-X increase to the rates and once through the Cn adjustment to the rates. The capital scaling factor (Scap) is designed to mitigate the risk of overfunding. Scaling factor is calculated as follows:

Scaling factor = (capital-related revenue requirement) / (total revenue requirement)

The scaling factor multiplied by inflation reduces the incremental funding for capital to capture the capital component incremental to the I-X already included in the CPCI.

The growth factor inclusion proposed by interveners was approved by OEB to capture the change in distribution revenues that would naturally occur (in the absence of any rate changes) due to changes in billing determinants over the forecast period.

3.3.2 Enbridge Gas Distribution Custom IR

EGD's 2014-2018 custom IR framework established through a negotiated settlement process is the only custom IR approved by OEB for natural gas utilities in Ontario.

Under EGD's custom IR, the O&M expenditures (excluding customer service charges, DSM costs and pension and OPEB[19]) were set based on a fixed annual increase to O&M base beginning with the 2014 proposed level. The OEB did not reduce the proposed base year O&M amount stating that the proposed increases to the base year O&M compared to its previous year approved and actual O&M was reasonable.

Capital expenditures on the other hand were set based on forecasts. As part of the negotiated settlement, EGD would forecast its capital expenditure for the first three years of the plan's five-year term and would fix its core capital budget for the last two year of the plan at third year forecast (EGD initially proposed to provide a forecast for the last two years of the plan in years three). However, EGD maintained that the capital costs for relocation and replacement of mains are unpredictable beyond third year and should be treated under a deferral account. OEB determined that EGD's modified proposals which were achieved through a negotiated settlement process were reasonable as the forecast remains flat in total for the final three years of the plan and the risk to be borne by EGD remains significant given the limitation of the variance accounts to two activities and the threshold revenue requirement of $5 million for their use.

Other elements of the EGD's custom IR included an asymmetric ESM where all overearnings are shared on an equal basis between ratepayers and shareholders.

[19] Customer care service charges were subject to an approved settlement agreement which determines costs for each year 2013 to 2018. DSM has it own separate regulatory process and Pension and OPEB costs are also subject to an agreement which determined that the utility should recover only its actual pension and OPEB costs over the IR term.

4. ONTARIO – UNION GAS AND ENBRIDGE GAS DISTRIBUTION AMALCO INCENTIVE RATE-SETTING PLAN

4.1 BACKGROUND AND DEVELOPMENT

After the merger of Enbridge Inc. and Spectra Energy the two leading Ontario natural gas utilities owned by these two companies, Union Gas and Enbridge Gas Distribution, became part of the same firm, Enbridge Inc. In order to increase efficiency, Union Gas and EGD applied to the OEB for approval to amalgamate the two utilities into a single entity beginning in 2019 and to defer rate rebasing from 2019 to 2029[20]. This amalgamation application was guided by OEB's "consolidation handbook", which provides guidance for electric utilities M&As. The handbook states[21]:

- A distributor on Price Cap IR, whose plan expires, would continue to have its rates based on the Price Cap IR adjustment mechanism during the remainder of the deferred rebasing period.
- A distributor on Custom IR, whose plan expires, would move to having rates based on Price Cap IR for the remainder of the deferred rebasing period.

In line with OEB's guidance, the utilities filed a separate application for an incentive rate setting mechanism for 2019 to 2029 period which is similar to OEB's 4th generation incentive rate setting mechanism for Ontario's electric distributors with some minor differences. The OEB however decided that it is more efficient to combine the amalgamation and rate-setting framework proceedings and issued a single decision for both proceedings. Using a "no harm" test, OEB concluded that the amalgamation meets the no harm test and approved the utilities' amalgamation request with some changes.

Further, OEB determined that a Price Cap IR for amalgamated utilities is appropriate and provides a sharing of the benefits of the amalgamation between ratepayers and shareholders. In following sections, the main elements of Amalco Price Cap IR plan are discussed in more detail.

4.2 DEFERRED REBASING PERIOD (PLAN'S TERM)

Prior to the amalgamation, both utilities were expected to file separate rebasing applications for 2019 rates[22]. However after amalgamation and in line with the OEB policy framework, the utilities proposed to merge and defer the rebase until 2029. The utilities argued that a ten year deferred rebasing period will allow the Amalco to integrate and have sufficient time to make the

[20] Under OEB's consolidation guidelines for electric utilities, consolidating utilities are allowed to select a maximum deferral period of ten years with no supporting evidence to justify the selected deferral period.

[21] OEB (2016); "Handbook to Electricity Distributor and Transmitter Consolidations", p.14

[22] Prior to 2019, Union Gas operated under a five-year price cap IR model approved by the OEB and ending in 2018. EGD on the other hand operated under a five year custom IR model similar to the one included in OEB's renewed regulatory framework for electric distributors.

capital and system investments necessary to generate integration synergies across the combined EGD and Union Gas operations.

The interveners generally commented that the OEB's consolidation guidelines which are designed for encouraging the merger of electric distributors do not apply to natural gas utilities and asked for an immediate rebasing of costs. They argued that this was supported by the Settlement Agreement in Union Gas' IRM Framework which required Union Gas to file a cost-of-service application in 2019 regardless of whether Union Gas applies to set rates for 2019 on a cost-of-service basis. Similarly, it was argued that Enbridge Gas made an equivalent commitment in the oral hearing of its Custom IR application.

Ultimately, the OEB decided to defer the rebasing to 2024 (a five year deferred rebasing period)[23]:

> The OEB finds that five years provides a reasonable opportunity for the applicants to recover their transition costs … The OEB is granting a five year deferred rebasing period consistent with its historic practice for other MAADs applications, and therefore is not requiring Union Gas to rebase for 2019.

This means that the amalgamated utilities' Price Cap IR plan will be in place for a five year period.

Despite proposing for a deferred rebasing period, Union Gas and EGD asked for four specific adjustments to their base rates. All four proposed adjustments were approved.

In following sections the main features of Amalco's Price Cap IR plan are discussed in more detail.

4.3 *MAIN FEATURES OF AMALCO IR PLAN*

4.3.1 PBR Formula

As mentioned earlier, in preparing their application, the utilities argued that the consolidation handbook applies equally to natural gas utilities as it does to electric utilities, and therefore followed the handbook's guidelines. Among other things, the guidelines state that the amalgamating utilities must adopt a Price Cap IR model. The OEB did not agree with the utilities' argument, indicating that the consolidating handbook was developed to incent the consolidation of electricity distributors and does not specifically reference natural gas utilities merger activities. Nevertheless the OEB agreed that the principles and objectives established in the Renewed Regulatory Framework apply to all utilities and found that it is reasonable to allow utilities to adopt a Price Cap IR rate-setting mechanism during the deferred rebasing period.

[23] OEB Decision (Aug, 2018); pp 22-23

The utilities' proposed Price Cap IR formula was similar to the one defined in the RRF for Ontario's electric utilities with two major differences discussed below:

4.3.1.1 Inflation Factor

In their rate-setting application, the utilities replaced the composite inflation factor consisting of labour and non-labour components used for Ontario's electric utilities with the quarterly Gross Domestic Product Implicit Price Index Final Domestic Demand (GDP IPI FDD) Canada index. The utilities provided a comparison of the inflation factor using GDP IPI FDD and using both GDP IPI FDD and AWE (70/30 weighted) which indicated that the difference between the two methodologies was not material.

The OEB agreed with the utilities that the GDP-IPI-FDD has been used by the natural gas utilities in the past and that the difference between this inflation factor and the composite factor adopted for Ontario's electric distributors is not material and therefore approved the utilities proposed inflation factor.

4.3.1.2 Application of Normalized Average Consumption (Average Use) Factor

Similar to Union Gas' 2014-2018 Price Cap IR, the Amalco utilities proposed that the price cap index should include an adjustment for changes in customers' average use (AU) also known as normalized average consumption (NAC). Based on utilities' proposal, the average use would be trued-up on an annual basis in order to reflect the declining trend in average use. The utilities' further explained that the objective of AU adjustment is to capture declines in average use not related to weather since the weather risk is already addressed by the weather normalization of the load. (This is in addition to the lost revenue adjustment mechanism (LRAM) applied to contract customers). The utilities also argued that without such an adjustment, they will have no motivation to aggressively pursue conservation initiatives.

In practice, an annual adjustment of utilities' average use effectively transforms the price cap index into a revenue adjustment formula. This is because the AU factor adjusts the volumetric charges of the affected rate schedules to reflect the measured change in average use in that particular rate class. If average use for customers on a particular rate declines, volumetric charges are increased proportionately to recover revenue losses associated with the measured decline. An increase in average use for customers on the rate would lead to an analogous decline in the volumetric charges and the revenue required.

The OEB agreed to maintain the NAC/AU adjustment for the deferred rebasing period however directed the utilities to develop a proposal for a single, revenue-neutral approach to average use adjustment that includes the LRAM mechanism for general service customers.

4.3.2 X-Factor Determination

In line with the OEB's guidance, the utilities filed a separate application for an incentive rate setting mechanism which is similar to OEB's 4th generation incentive rate setting mechanism for

Ontario's electric distributors with a proposed X-Factor of zero percent (similar to the zero productivity growth target approved in OEB's 4th generation IR).

The utilities retained the services of Dr. Makholm of NERA to conduct an industry productivity growth study and X-Factor recommendation. Dr. Lowry of PEG was retained by the staff to comment on NERA study and provide an X-Factor recommendation.

Similar to the updated NERA studies conducted in Alberta, Dr. Makholm's updated study for Union Gas and EGD indicates a downward trend during the last 10 to 15 years. The above graph also shows that there is no clear relationship between Canada economy-wide productivity growth and industry productivity growth in recent years. Referring to this downward trend in utility industry productivity over the recent years, Dr. Makholm commented[24]:

> There is a definitive trend there that is impossible to overlook. The past six years show negative TFP growth (as do 8 of the last 10 years). Indeed, only 5 of the past 15 years have shown positive TFP growth, whereas 15 of the 15 years before showed positive TFP growth. There is a lot going on with these data that points to a downward trend in measured TFP growth for that population of companies—either by themselves or in relation to the Canadian economy as a whole.

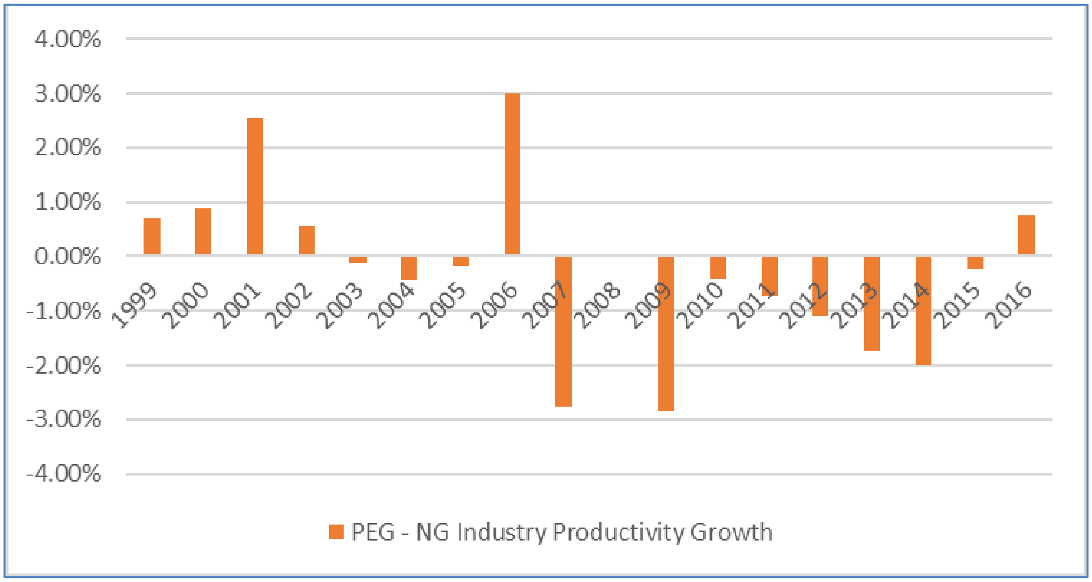
OEB staff asked Dr. Lowry of PEG to comment on NERA's report and provide a separate TFP study. PEG filed its report in May 2018 (this is the most recent report included in this review).

Considering Dr. Lowry's own natural gas industry TFP growth study values (which indicated a negative productivity growth value of -0.23 percent), PEG concluded that the zero percent base TFP growth trend proposed by NERA is reasonable. PEG also proposed a stretch factor of +0.3 percent for a total recommended X-Factor of +0.3 percent similar to the approved X-Factor in Alberta and Quebec and in line with the stretch factor used for average efficiency cohort for Ontario's electric distributors.

The result of PEG study industry productivity growth trend for a sample of U.S. based natural gas utilities for each year of the sample period is presented in the Figure A:C4-1 below with an average productivity growth of -0.23 percent.

[24] NERA Study (Nov 2017); "Expert Report and Direct Testimony by Jeff Makholm", p.27

Figure A:C4-2-1: Lowry Study, Natural Gas Industry Productivity Growth Trend



As can be seen from the above graph, 11 out of the last 15 years of the sample period show a negative TFP growth (2008 growth is close to zero percent). This is similar to the negative and declining productivity growth trend presented in NERA's study.

On August 30, 2018 OEB issued its decision approving the amalgamation of two utilities and their proposed price cap formula. Alluding to the identical base TFP growth numbers recommended by both experts, the OEB determined there is no need to comment on the details of TFP studies conducted by experts and relied on experts' judgement to approve the recommended zero percent base industry TFP growth[25]:

> The OEB accepts the applicants' proposal for a productivity factor of 0% during the deferred rebasing period. There were two expert reports filed in evidence in this proceeding on the productivity factor; one from NERA for the applicants and another from PEG for OEB staff. While the approach to determining an appropriate productivity factor differed, both experts recommended a productivity factor of 0%. Considering that the experts' recommendation is the same, the OEB will not opine on the merits of the methodology adopted in the reports.

The OEB also found the amalgamation will provide additional opportunities to find efficiencies that are not available to individual utilities and therefore a 0.3 percent stretch factor would be appropriate during the amalgamation period[26]:

> A key objective of the OEB's incentive regulation is to drive improvements in cost efficiency. This would have been an expectation regardless of the amalgamation.

[25] OEB Decision (Aug, 2018); pp 25-26.
[26] Ibid, p.27.

> The amalgamation provides additional opportunities to generate cost savings, and the applicants have proposed a number of initiatives for this purpose. The stretch factor provides incentive to find further efficiency improvements beyond those proposed.

As a result of the zero percent base productivity growth and 0.3 percent stretch factor, the final X-Factor amount in Amalco's PBR plan is set at 0.3 percent.

4.3.3 Z-Factor Treatment

Consistent with the RRF, the OEB approved the inclusion of a Z-Factor mechanism for costs meeting all of the four criteria set out below:

- The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event.
- The cost increase or decrease must meet a materiality threshold, in that its effect on the gas utility's revenue requirement in a fiscal year must be equal to or greater than $5.5 million.
- The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence.
- The cost subject to an increase or decrease must have been prudently incurred.

4.3.4 Y-Factor Treatment

Y-Factor was defined as costs associated with specific items that are subject to deferral account treatment and passed through to customers without any price cap adjustment. Under Amalco's IR plan some of the items that will be treated as Y-Factors include:

- Cost of gas and upstream transportation
- Demand Side Management (DSM) costs
- Lost Revenue Adjustment Mechanism (for the contract market)
- Normalized Average Consumption/Average Use

As mentioned earlier, the OEB directed the Amalco to develop a proposal to be filed in its next rebasing application to replace the NAC/AU and LRAM mechanisms. Alternatively, if Amalco wants to maintain the existing mechanisms, it must file evidence in support of that approach.

In addition to these cost items, other deferral accounts such as Tax Variance Deferral Account (TVDA), used to record the impact of any tax rate changes or Earnings Sharing Deferral Account, to record the ratepayer share of utility earnings were established.

4.3.5 Earnings Sharing Mechanism (ESM)

Without rebasing, the amalgamated utilities' revenues can significantly exceed the costs leading to excessive utility gains during the deferred rebasing period. The OEB noted that both utilities have had long history of using ESMs as part of their incentive rate-setting frameworks and therefore determined that an asymmetrical earnings sharing mechanism is necessary to enhance the alignment between rate payers and utilities interests during the deferred rebasing period[27]:

> The OEB approves an asymmetrical earnings sharing mechanism that will share earnings on a 50/50 basis between Amalco and its customers for all earnings in excess of 150 basis points from the OEB-approved return on equity.

The OEB further determined that the use of actual earnings (as opposed to weather normalized) is a simpler approach to assessing the earnings that will be shared and should be adopted by the Amalco for ESM purposes.

4.3.6 Safeguard Mechanisms (Off-ramps/ Re-opener)

Unlike the Price Cap IR plan for electric distributors, the utilities did not propose any off-ramp or re-opener provisions. The OEB however determined that an off-ramp is necessary to protect the interests of both customers and Amalco and adopted an off-ramp mechanism similar to the one described for electricity distributors in the Renewed Regulatory Framework. Therefore if non-weather normalized earnings during the deferred rebasing period are outside of +/- 300 basis points from the OEB-approved ROE, a regulatory review may be triggered.

4.3.7 Incremental Capital Module (ICM)

The OEB recognized that both EGD and Union Gas had mechanisms for funding of incremental capital in their last rate frameworks[28] and determined that it is appropriate to have a mechanism for the funding of incremental capital needs for the Amalco as well. The OEB therefore approved an incremental capital module plan similar to the one applied to electric utilities under Price Cap IRs. Under OEB's policy, an ICM project is a discrete, incremental project that is not part of typical annual capital programs and that is above the materiality threshold calculated by a predefined formula. Consistent with OEB's ICM policy for electric distributors, the eligible incremental capital amount will be determined using the OEB's ICM formula and each gas utility's rate base and depreciation, i.e. calculated individually for both Union Gas and Enbridge Gas.

The ICM policy further states that any incremental capital amounts approved for recovery "must clearly have a significant influence on the operation of the distributor". To provide greater regulatory certainty, the OEB decided to define the "significant influence" for Amalco as any

[27] OEB Decision (Aug, 2018); page 29
[28] EGD through is Custom IR and Union Gas through its capital pass-through mechanism.

individual project with an in-service capital addition of at least ten million dollars. This is different from the materiality threshold calculated by the formula, as the formula-driven threshold is the total capital expenditure level above which incremental capital can be requested, while the ten million dollars threshold is only at the individual project level and can only apply after the formula-driven materiality threshold is met.

The rate riders for any ICM would be determined as part of the rate proceeding in which the ICM is approved. The rate riders continue until the next rebasing application. In that rebasing application, the OEB will review the spending against plan to determine if any true-up is warranted.

The OEB also stated that similar to distribution system plans filed by electric utilities to support their ICM applications, the Amalco must file a consolidated utility system plan (USP) to support any ICM request for 2021 rates and beyond.

4.3.8 Service Quality Indicators

Consistent with Renewed Regulatory Framework document developed for electric distributors, the utilities proposed to use a single scorecard to measure and monitor performance over the rebasing period. The scorecard metrics included a combination of existing metrics, service quality indicators and best practice metrics. The utilities argued that the use of existing SQIs would help ensure that Amalco's progress can be compared relative to its past.

The OEB determined the scorecard as proposed by the utilities is reasonable and therefore can be used for Amalco's IR plan. The OEB further determined that in addition to the SQIs, the Amalco should include two unit cost metrics for total cost per customer and total cost per KM of distribution pipeline. The OEB's decision did not consider any automatic penalty mechanism if the Amalco fails to meet the scorecard targets.

5. QUEBEC – 1ST GENERATION PBR PLAN FOR HYDRO QUEBEC DISTRIBUTION AND HYDRO QUEBEC TRANSMISSION

5.1 *BACKGROUND AND DEVELOPMENT*

Article 48.1 of "La loi sur la Régie de l'énergie" (or Act respecting the Régie de l'énergie) requires the Regie to establish an incentive regulation mechanism to promote efficiency gains for electric utilities. By procedural decision D-2015-103, the following three phase proceeding was established to address the legislative requirement:

- Phase 1: Determination of plan's main features
- Phase 2: The productivity factor studies
- Phase 3: Detailed design of the PBR elements

However, pursuant to the Regie's decision in Phase One of the proceeding to accept utilities' proposal for judgement-based X-Factor determination approach, Phase Two was eliminated. In the following sections the main features of HQD's and HQT's first generation PBRs plan are discussed.

5.2 *MAIN FEATURES OF HQD'S PBR PLAN*

5.2.1 Plan's Term

HQD's performance-based ratemaking plan was set for a four year period with one year of cost of service for determining the going-in rates (2018) and three years of revenue generated by the PBR formula (2019-2021). In the Regie's opinion, anything less than four years (as was proposed by some interveners) is not long enough to allow the utility to find durable efficiency gains.

5.2.2 PBR Type and Formula

To address legislative requirements, HQD applied for a revenue cap model in which the revenue requirement for the base year is compounded by an index formula comprising of an inflation factor, an expected productivity factor as well as a growth factor. The Regie agreed with HQD and the majority of interveners that the revenue cap formula is an appropriate model for its first generation PBR. In Regie's opinion the revenue cap approach provides a simple model for transitioning from the cost of service regulation to incentive regulation.

Therefore the following formula was approved for HQD's revenue cap plan:

$$RR_{t+1} = RR_t * (1 + I_t - X + G_t)$$

Where

RR = Revenue requirement
I = Inflation Factor
X = Expected productivity factor
G = Growth Factor

5.2.2.1 Inflation Factor (I-Factor)

The Phase One decision (D-2017-043) stated that the inflation factor should be comprised of both labour and non-labour inflation indices. Consequently Quebec's Average Weekly Earnings (AWE) was selected as the labour related inflation factor and Quebec CPI as the non-labour related price index.

The Regie further determined that the labour inflation factor (Quebec's AWE) should be based on a three year average of historical data. In the Regie's opinion, this approach will mitigate the related volatilities and is more in line with the actual labour inflation pressures faced by the utility as the labour cost pressures caused by collective bargaining processes with unions and contract renewals with outsourcing contractors are fixed for a number of years. As for the non-labour component, the preceding year actual Quebec-CPI is used.

In the Phase Three decision (D-2018-067) these issues were re-examined; however the determinations made in the first phase were maintained. The issue of the appropriate weighting between labour and non-labour components of the composite inflation factor was also discussed in the Phase Three decision. In the Regie's opinion, the weighting for labour and non-labour inflation factors should remain fixed over the term of the PBR plan and calculated based on their respective share in the base year revenue requirement.

5.2.2.2 X-Factor Determination

In the Phase One decision (Decision D-2017-043), the Regie concluded that the X-Factor could not be appropriately set without consideration for other elements of the formula and that the X-Factor determination requires informed judgement to reflect HQD's prior efficiency gains and other relevant HQD-specific circumstances that determine HQD's ability to achieve efficiency gains over the term of the PBR plan. The Regie further indicated that the following factors support the use of the judgement approach as proposed by the distributor:

- The range and variance of TFP study results already available in other jurisdictions and generated by various experts
- The HQD's commitment to limit the rate increase to the level below or equal to the rate of inflation
- And the fact that conducting the TFP study would further delay the final decision for PBR plan

In conclusion, the Regie accepted the judgement approach recommended by HQD for X-Factor determination and asked the utility to file any study or analysis that could be used to inform the Regie's final decision in Phase Three of the proceeding.

The Regie's final decision on X-Factor determination affirmed that the industry productivity growth is experiencing a downward trend in recent years and that in many jurisdictions this issue has resulted in approval of lower X-Factor values. However in the Regie's opinion this negative productivity trend does not necessarily require a negative X-Factor and that HQD's approach of relying on a simple arithmetic average of recent productivity values without considering the regulators' decisions and without integrating the hypothesis and the context of these studies is insufficient. In particular the Regie affirmed that regulators' final decisions in these proceedings are essential for a credible recommendation as a regulator must examine all the evidence before reaching to its final X-Factor value determination.

In this context, the Regie set HQD's X-factor at +0.3 percent similar to AUC's X-Factor decision. The Regie further determined that there will be no additional stretch factor applied to this value.

5.2.2.3 Growth Factor

As mentioned earlier, the revenue cap formula approved by the Regie for HQD's PBR plan includes a growth factor to account for the growth in costs caused by increased demand or growth in utility's operating scale. Based on submissions from the distributors and interveners, it was determined that the growth in number of customers is a principal cost driver for HQD's costs and therefore was selected as the appropriate measure for a growth factor in HQD's revenue cap formula.

Further it was determined that a 0.75 multiplier should be applied to the growth factor to account for the fixed costs that may not change in short or medium term with the growth in number of customers. This means that a 1 percent increase in number of customers will lead to a 0.75 percent increase in utility's revenue requirement under the formula.

5.2.3 Y and Z Factor Treatment

The Regie recognized that, subject to certain conditions, some elements of distributor's costs should be treated outside the PBR formula. In this context, the following criteria for Y and Z factor treatment of utility costs were established:

Table A:C4-2-8: Regie's Criteria for Y and Z Factor Treatment

Y-Factor	Z-Factor
Known and recurring events	Unforeseen events
Outside the control of utility management	Outside the control of utility management
Unpredictability/volatility of the dollar amount required for each event	Unpredictability of the dollar amount required for each event
A materiality threshold	A materiality threshold

As can be seen, with the exception of the first criterion, the same criteria are applied for both Y and Z factors.

The HQD application proposed that the costs related to power purchases, electricity transmission, fuel consumption, pensions and demand-side management be considered for Y-Factor[29] treatment. In the Phase One decision, the Regie determined that the power purchase and transmission costs, as well as the demand-side management expenditures can be treated as Y-Factors. However, in the Regie's opinion, pensions and fuel related costs did not meet the Y-Factor criteria and therefore the Y-Factor treatment for these costs was denied.

Pension cost eligibility for Y-Factor treatment was re-examined in the Regie's decision D-2018-0687 (Phase Three decision). The Regie acknowledged that ordinarily pension cost volatility stems from the variations in discount rates and return on assets which are outside the control of the utility. Further, the study of variations in HQD's pension costs indicated that these costs

[29] Prior to PBR, all of these costs were treated in deferral accounts.

have regularly exceeded the materiality threshold criterion for Y-Factor treatment. Therefore based on the evidence provided in the Phase Three proceeding, the Regie reconsidered its initial finding and determined that the pension-related costs are eligible for Y-Factor treatment. The Phase Three decision further clarified that the materiality threshold applies to the total amount of the cost item.

5.2.4 Earnings Sharing Mechanism

In the Regie's opinion, an earnings sharing mechanism can mitigate some of the risks attributed to a PBR plan (such as the risk of excessive earnings caused by significant variances between the revenue generated by the formula and the actual costs), allowing for a longer PBR term. Additionally, the inclusion of an ESM in the PBR plan is aligned with the objectives of the legislative requirement that the reduction in costs should be profitable for both customers and the utilities. Therefore, the Regie decided to include an earnings sharing mechanism in HQD's PBR plan. The main features of this mechanism are as follows:

- An asymmetric ESM with all negative variances to the account of the utility
- Any variance between the realized and approved ROE that is less than 100 bps will be shared equally between ratepayers and utility
- Any variance between the realized and approved ROE exceeding 100 bps will be shared at a 75:25 ratio in favour of the ratepayers

5.2.5 Capital Exclusion Mechanism

Unlike the regulators in other Canadian jurisdictions, the Regie did not establish a separate mechanism for treatment of incremental capital outside the formula. The Regie did however agree that significant and unusual capital projects can be considered as investments caused by exogenous factors and treated as a Z-Factor (if eligible).

5.2.6 Other Issues

In first phase decision, the Regie concluded that the five categories of service quality indicators should be tracked and reported by the HQD. These included customer satisfaction, customer service, reliability, power supply and safety indicators. The Regie further commented that it is better to use those indicators that are already tracked and reported by HQD. This will ensure that utility's non-financial performance during the PBR can be compared with the performance prior to PBR. However, the determination of the exact definition of service quality indicators and their targets was deferred to a later time.

Similarly, the first phase decision concluded that there will be a need for an off-ramp provision during the PBR term in case there are fundamental issues with PBR plan design. However, the design of the off-ramp or a re-opener provision was deferred to a later time.

5.3 HYDRO QUEBEC TRANSMISSION PBR PLAN'S FEATURES

Regie's phase one decision regarding Hydro Quebec Transmission's PBR plan was released in January 2018 (decision D-2018-001).

HQT's PBR plan features approved in phase one decision have several similarities with HQD's PBR plan components. Namely, HQT's PBR plan features similar plan term, composite inflation factor and earning sharing adjustment. The Y-Factor and Z-Factor criteria are also similar although the dollar amount for materiality threshold is different. Further similar to Regie's decision in HQD's case, a judgement-based approach to X-Factor determination was deemed appropriate although the actual X-Factor value determination was deferred to the next phase decision[30].

The biggest difference between the two plans relates to the treatment of capital investments. Under HQD's plan both capital investment and O&M expenditures are covered by I-X formula while HQT's PBR plan is in the form of a hybrid building block revenue cap model where the O&M expenditure is set based on the indexing formula while the capital expenditures are forecasted using the traditional cost of service ratemaking model. In Regie's opinion, the exclusion of capital from revenue cap formula is justified since the depreciation and return on rate base for HQT do not fit to any smooth trajectory and rather are highly variable.

6. PERFORMANCE INCENTIVE FRAMEWORKS IN U.S.

The recent advances in information technology and network operations as well as public policy push in various U.S jurisdictions for greenhouse gas (GHG) emission reduction and non-traditional utility solutions such as more distributed energy resources (DER)[31] and non-wire alternative (MWA) programs have persuaded a number of U.S. regulators to take a fresh look at utilities' traditional revenue models. These regulators are increasingly questioning their total reliance on traditional cost of service regulation for the "utility of future" and are exploring alternative incentive frameworks to complement the incentives embedded in traditional cost of service regulation. These new incentive frameworks are often in the form of expense capitalization for operational expenditure intensive initiatives that are aligned with government policy (similar to capitalization of DSM expenses for FEI and FBC) and/or positive earning opportunities for targeted outcomes.

In following sections, alternative incentive mechanisms adopted for New York's Reforming the Energy Vision (REV) initiative and California's utility incentive pilot plan for competitive solicitation framework are presented in more detail. Both jurisdictions are known for their more progressive regulatory environment and are suitable examples for understanding the recent developments in alternative incentive frameworks adopted by US regulators.

30 At the time of drafting this appendix, Regie's decision for HQT's phase 3 proceeding was not published yet.

31 The term "DER" is used to describe a wide variety of distributed energy resources, including end-use energy efficiency, demand response, distributed storage, and distributed generation. DER will principally be located on customer premises, but may also be located on distribution system facilities.

6.1 *NEW YORK'S REFORMING THE ENERGY VISION (REV) INITIATIVE*

6.1.1 Background and Development

Reforming the Energy Vision (REV) is the title of New York's comprehensive energy strategy plan initiated by the State's Governor, Andrew Cuomo in 2015. REV initiative aims to reorient both the electric industry and the regulatory paradigm toward a consumer-centered approach that harnesses technology and markets and to integrate DER into the planning and operation of electric distribution systems, to achieve optimal system efficiencies, secure universal, affordable service, and enable the development of a resilient, climate-friendly energy system[32].

New York's Public Service Commission (PSC) is playing an important role in introducing the significant regulatory changes required to achieve REV's objectives. Implementation of REV's objectives would require utilities to design systems that are adaptable and supportive of third party DER investments. This in turn as explained by New York's PSC could mean increased operational expenditures for planning and operation of networks and less utility capital investments in traditional distribution and transmission projects:

> In order for utilities to enable these developments, they must take actions that run counter to the practices that are encouraged by traditional ratemaking. At the planning and operational level, this means enabling markets for distributed resources that will complement, and eventually transform, the centralized unidirectional system. At the revenue and earnings level, this means actively pursuing results that could be adverse to the interests of a utility under classical ratemaking. These results include lower sales volume, reduced capital expenditures, and greater reliance on market-driven outcomes as opposed to cost-of-service inputs ... Absent some change, the mix of resources that is most effective and efficient from the whole system's perspective will not be consistent with the utility's inherent financial interest[33].

Recognizing the disincentives inherent in cost of service regulation, New York's PSC initiated a second proceeding to reform utilities' financial incentive, to remove or minimize any self-interest that might be opposed to the successful implementation of REV initiative. PSC's May 2016 decision titled "Order Adopting a Ratemaking and Utility Revenue Model Policy Framework" provides the general framework to reform utility revenue model to one that can support REV initiative.

6.1.2 Main Features of REV's Utility Revenue Model

The new revenue model is built on the foundation of the conventional cost of service ratemaking and adds a combination of market-based platform earnings and out-come based positive

[32] CASE 14-M-0101 (Feb,2015); "Order adopting regulatory policy framework and implantation plan"; p.6
[33] CASE 14-M-0101 (May,2016); "Order adopting a ratemaking and utility revenue model policy framework"; pp.35-36

earning opportunities that will encourage utilities to achieve REV's main objectives. The New York electric utilities will have four ways of achieving earnings:

- Traditional cost of service earnings and related reforms
- Earnings tied to achievement of alternative solutions, such as non-wire alternative projects, that reduce, replace or defer conventional distribution and transmission capital investments and provide definitive consumer benefits
- Earnings from market-facing platform activities referred to as Platform Service Revenues (PSRs)
- Earnings from transitional outcome-based performance measures referred to as Earning Adjustment Mechanism (EAM)

As stated in New York's PSC decision, these four earnings opportunities are designed to encourage utilities to facilitate the implementation of REV initiative and to align the interests of utility shareholders and consumers[34]:

> These additional measures are collectively intended to create a regulatory environment where utilities can create shareholder value, comparable to or superior to conventional investments, by integrating third-party solutions and capital that improve the efficiency, resiliency and flexibility of the physical networks, reduce consumer total costs and achieve the State's policy objectives.

In following sections, each one of these revenue models is described in more detail.

6.1.2.1 Cost of service model and related reforms

In majority of cases, New York's MRPs are in place for a three-year period and are based on forecast cost of service for the duration of the MRP (rather than using formulas). Most New York MRPs include revenue-decoupling mechanisms that effectively transform these plans to a variation of revenue cap type plans. New York utilities' MRPs may also include earning sharing mechanisms.

Utilities are discouraged from increasing their near-term earnings by withholding funds from capital projects that were included in base rates through the net plant reconciliation mechanism, also known as "clawback mechanism". Clawback mechanism provides that earnings from capital programs that fall below the approved levels must be returned back to customers. Under REV however utilities will be encouraged to pursue DER alternatives which replace capital investments with operational expenditures. Therefore, clawback mechanism would result in utilities forfeiting their capital earnings with no offsetting compensation and a risk of absorbing the DER operational cost that were not reflected in forecasts. To remedy this issue, the PSC approved that earnings on capital projects already reflected in base rates, may be retained until

[34] Ibid, p.2.

the next rate case if the utility can demonstrate that the mentioned capital project was replaced with DER project. These earnings would be offset by the utilities absorbing the incremental operational expenses not reflected in forecast.

As highlighted in the following excerpt from PSC's May 2016 decision, traditional cost of service revenue model continues to be the main building block of utilities' revenue requirement with new revenue models complementing the traditional cost of service model[35]:

> Utilities as delivery companies will retain many of the attributes of natural monopolies, and will still need to deploy large amounts of capital with an opportunity to earn a fair return. Increasingly, however, and complementing the opportunity to earn a fair return, earnings must be connected to increased consumer value.

6.1.2.2 Platform Service Revenues

The so-called platform service revenue or PSR is the most progressive and futuristic of the four revenue streams. As mentioned earlier, one of the core objectives of REV initiative is to increase third party market participation and to create a more multi-directional retail market (as opposed to a centralized energy model with unidirectional flows and minimal elasticity of demand). In this context, utilities will increasingly act as distributed service platforms:

> The reformed electric system will be driven by consumers and non-utility providers, and it will be enabled by utilities acting as Distributed System Platform (DSP) providers. Utilities are responsible for reliability, and the functions needed to enable distributed markets are integrally bound to the functions needed to ensure reliability[36].

> The DSP will have the responsibility to offer services whether in the form of information, interconnection or dispatch services at prices and under terms allowed by the Commission. At the same time, because of the value that they provide to the grid, DER providers and their customers are entitled to compensation from the DSP. This transactive relationship expands the value of the system and is central to a changing relationship wherein the traditional utility and end use customers welcome DER as a mechanism to enhance economic and environmental value through a fully integrated grid[37].

PSRs therefore are new transactive-based revenues between and among distributed service platforms, end-use customers and third party market participants. New York's PSC did not provide an exact definition of PSRs but rather recognized that the definition and types of PSRs will evolve with time:

[35] Ibid, p.5
[36] CASE 14-M-0101 (Feb,2015); "Order adopting regulatory policy framework and implantation plan"; p.12
[37] Ibid, p.41

> To simplify, we adopt a single category of revenues, to be known as platform service revenues, which represent all new forms of utility revenues associated with the operation or facilitation of distribution-level markets. The precise nature and characterization of PSRs will evolve as markets evolve. Therefore, rather than establishing rigid definitions, we will adopt a process-based approach for approving new charges and revenues, which will evaluate proposed utility activities on an individual basis.

The following list provides the major features of PSRs:

- All platform service charges and revenues must be authorized by tariff.
- Since PSRs derive from monopoly function, in most cases a large portion of these revenues should be to the benefit of rate payers (similar to the way sharing of benefits related to natural gas and/or power supply mitigation incentive programs).
- Although PSRs derive from a ratepayer-funded platform, their pricing need not be strictly cost-based.
- Because the total levels of PSRs will not be easily predictable, they should not be imputed to revenue requirements in early years but instead should be used to create customer credits.
- In a mature market environment when PSRs are both large and more predictable, it will become appropriate to impute the revenues when developing rate plans.

In the interim and until a distributed system platform with more transactive and distributed market is developed, utilities can increase their earning opportunities through non-wire alternative projects and/or positive earning adjustments mechanisms (discussed in sections below).

6.1.2.3 Earnings from Non-Wire Alternatives

Non-wire alternative projects are ordinarily referred to the type of projects that would replace, reduce and/or defer traditional capital infrastructure investments that otherwise would be needed to accommodate the growth in expected locational peak demand. New York PSC describes the earning opportunity from NWA projects as follows[38]:

> Until platform markets are fully developed, distinct n/w/a projects are a means by which third-party investment can be integrated with utility systems to improve efficiency and reduce bills. As we did in the BQDM proceeding, we expect to approve n/w/a projects that will result in customer savings, with earnings opportunities for utilities that are commensurate with or superior to earnings that can be achieved through traditional investments.

[38] Ibid, pp.46-47

Con Edison's Brooklyn Queens Demand Management (BQDM) project referred to in the above excerpt is probably the best-known NWA project example. The BDQM project was implemented to address load growth needs of customers through a combination of traditional utility capital investments and unconventional non-wire solutions, such as the use of distributed energy resources. These NWA solutions were designed to defer significant capital investments (estimated to be around one billion dollars) for new area substation, switching station and sub-transmission feeders. To ensure that the utility is indifferent to investments in DER and traditional infrastructure investment with higher rate base growth potential, the New York's PSC approved several unique financial incentives. These included the capitalization of all related expenditures and reduced amortization period of 10 years as well as allowing for a 100 bps premium over the authorized return tied to achieving certain out-come based performance metrics[39]:

> While BQDM is ground breaking from the standpoint of system planning and operations, it also demonstrates the new direction in ratemaking established here. Recognizing that the utility is displacing capital investment with operating expenses, and thus foregoing the growth of its rate base, the Commission authorized a return on total program expenditures, as well as performance incentives tied to the achievement of goals that will produce customer savings. While the details in approaches will evolve, BQDM represents a new direction of aligning utility financial incentives with the best interests of customers.

Since the BQDM decision, Central Hudson, Con Edison and other New York utilities have proposed and received approvals for several other smaller NWA projects. For instance, Central Hudson NWA project would delay capital investments for three different projects by 10, 7 and 5 years by achieving 10 MW, 1 MW and 5 MW demand reductions in three areas of its service territory respectively[40]. The anticipated load reductions would be achieved through a combination of residential and small commercial load control (both direct load control of thermostats and load control switches to automate cycling of air conditioning units, hot water heaters and various pumps) as well as industrial targeted demand response.

The amount of financial incentives attached to MWA projects is decided on a case-by-case basis and would depend on factors such as the magnitude of the alternative investments, the deferred investment period of the traditional capital investments and likelihood of achieving customer savings[41]:

> Concerning projects where the utility is pursuing NWAs, relevant factors to consider when establishing an upper limit are the level of anticipated customer savings, the likelihood of success, the magnitude of earnings that the traditional investment would have produced during the period of deferral, the level of

39 Ibid, p.6
40 Case 14-E-0318 (July, 2016); "Cost recovery and incentive mechanism for non-wire alternative project"
41 Ibid, p.9

shareholder risk being taken, and the opportunity for additional earnings from non-wire alternatives.

In the case of Central Hudson, the PSC adopted a sharing of benefits approach that provides 30 percent to shareholders and 70 percent to ratepayers. The company can recover all of the prudently incurred costs of the project as well as to earn its allowed return on such deferred costs. The NWA project cost recovery is provided even if, ultimately, the construction of the traditional transmission and distribution capital is not deferred for the full period envisioned.

6.1.2.4 Positive Earning Adjustment Mechanism

Earning adjustment mechanisms (EAMs) are near-term measures and serve as a bridge to PSRs. Over time, as PSRs become a larger component of utility revenue, the need for EAMs should diminish. EAMs are also distinguished from the earning incentive from NWA projects that are considered on a case by case basis.

The New York PSC set the following general guidelines for EAM proposals:

- <u>The EAMs should ordinarily be outcome-based not program-based:</u>

  In developing EAMs an approach based on outcomes that align with policy objectives, rather than an approach based on specific utility inputs is preferred. This is because utilities do not have direct control over third parties but can enable markets to drive outcomes. Further, outcome-based incentives encourage innovation as opposed to merely conforming to plans ordered by PSC.

- <u>EAM incentives shall be designed in a manner that would avoid counterfactuals:</u>

  Incentives that are tied to determination of what would have taken place in the absence of the incentive, that is proving of a counter-factual, are controversial and administratively inefficient. Therefore where appropriate metrics should establish fixed performance targets on a pre-determined basis.

- <u>EAM incentives shall ordinarily be positive only:</u>

  Negative earning adjustment attached to performance targets are usually intended to deter problems and less they are actually imposed, the better for customers. Most EAMs, in contrast, are established for activities with positive value, therefore more they are awarded, the better for customers. Therefore, the EAM incentives are generally positive only. Negative adjustments are reserved for exceptional instances of inadequate effort or performance.

- <u>The maximum amount of earnings for the initial EAM incentives should not be more than 100 basis points:</u>

  The PSC stated that there is no established formula for determining correct level of earning adjustments. The value of individual EAMs may vary based on the underlying activity, its anticipated cost, value to customers and relative degree of opportunity in the particular utility territory. Nevertheless, for the first round of REV initiated EAMs, the maximum amount of earnings should be limited to 100 basis point from all new incentives. Further, although the initial potential rewards are referenced in basis points, the next rounds of EAM incentives should not be directly tied to basis points. Rather utilities shall calculate the maximum award with reference to basis points and then translate that maximum award dollar amounts.

- Each proposed EAM should be in place for a number of years:

  Outcome-based incentives should be generally structured on a multi-year basis to allow the utilities to achieve the desired outcomes.

Based on the above mentioned general guidelines, the utilities may propose EAMs in the following major categories.

6.1.2.4.1 SYSTEM EFFICIENCY

Each utility shall propose system efficiency targets that include both peak reduction and load factor improvement. These targets will accompany energy efficiency targets and should be implemented in a manner that achieves an optimal balance among peak reduction, load factor improvement and energy efficiency efforts. Each proposal shall include a benefit cost analysis and propose positive earning incentives commensurate to the level of economic savings.

Parties argued that peak reduction is suitable for program specific approach rather than outcome-based approach. For immediate purposes, PSC agreed that utility specific strategies are the most efficient way for cost effective near-term system efficiency results. However PSC will not approve detailed programs that utilities will be bound to follow. Rather it will approve targets and incentives.

6.1.2.4.2 ENERGY EFFICIENCY

Positive only earning opportunities for energy efficiency metrics are not new and have been in place in New York for a number of years. Energy efficiency related performance incentive mechanism under REV will maintain this model. Utilities can propose their own metrics but PSC explicitly ordered the utilities to include a usage intensity type metric (such as Kwh/capita, kwh/customer/ kwh/GDP, …) in their proposals. In PSC's judgement, positive earnings attached to usage intensity metrics can encourage utilities to facilitate ESCOs and DERs operations.

6.1.2.4.3 INTERCONNECTION

Improving the interconnection process will promote market development of DERs. New York PSC recognized that the complexity and cost of interconnection process are correlated with the size of the facility. Therefore, the interconnection EAM will be designed for projects that are over 50 KW.

Successful interconnection process requires three main attributes: high quality applications, timeliness and reasonable costs. Considering these attributes, the interconnection EAMs include the following components:

- A threshold condition based on timeliness requirements of standard interconnection requirement guidelines
- A positive adjustment based on an evaluation of application quality and satisfaction of applicants as measured by (i) a satisfaction survey and (ii) a periodic and selective third party audit of failed applications to asses accuracy, fairness and key drivers of failure.

Although these EAM incentives are positive only, the commission may apply negative adjustments on a case-by-case basis for inadequate effort or performance.

6.1.2.4.4 GHG REDUCTION

Under REV initiative, the new clean energy standards (CES) for achieving State's renewable energy adoption and GHG emission reduction targets are set in a separate proceeding. Depending on the mandate that is established in the CES, including the extent of utility responsibility and the mechanism for enforcement of the mandate, metrics for GHG emission reduction may be added to the EAMs. Further, utilities' rate cases should include earning opportunities tied to reducing the cost of achieving the CES goal.

The New York PSC further encourage utilities to propose programs and strategies to enable and facilitate the beneficial conversion of end-uses. These proposals may contain positive earning opportunities lined to estimated customer savings.

6.1.2.4.5 CUSTOMER ENGAGEMENT

Because customer engagement underlines the majority of other outcomes (from interconnections to system efficiency) that may result in utility earnings and because the principal customer engagement tools are mandated, it does not require an additional EAM incentive.

New York PSC may however consider specific customer engagement EAMs for adoption and success of innovative utility programs. This could include things like the uptake of optional TOU rates or initiatives related to fuel switching (such as EV adoption and ground source heat pump).

6.1.2.4.6 AFFORDABILITY

As DSP markets develop, a uniform approach to outcome-based affordability related EAMs may be appropriate. In the interim, the termination and arrearage metrics will be considered in rate plans on a case by case basis.

6.2 CALIFORNIA'S COMPETITIVE SOLICITATION FRAMEWORK FOR DER SERVICES

6.2.1 Background and Development

The Competitive Solicitation Framework for DER services is California Public Utilities Commission's (PUC) response to challenges of developing DER services and NWA projects under the traditional cost of service rate setting.

PUC's decision 16-12-036 titled "Decision addressing competitive solicitation framework and utility regulatory incentive pilot" released in December of 2016 provided policy consistency for the direction and review of DER competitive solicitation process, from identifying the appropriate projects and evaluating the DER applications, to procurement, contracting and reporting requirements. The decision also established a pilot incentive mechanism to encourage utilities and to assess the role of incentives.

PUC adopted the following definitions for the distribution services that DER can provide for the competitive solicitation framework:

- Distribution Capacity services: Load modifying or supply services that DER provide via the dispatch of power output for generators or reduction in load that is capable of reliably reducing net loading on desired distribution infrastructure;
- Voltage Support services: Substation and/or feeder level dynamic voltage management services capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems; and
- Reliability (Back-Tie) and resiliency (microgrid) services: Load modifying or supply service capable of improving local distribution reliability and/or resiliency. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations;

Each utility shall identify one project to test the framework and an option for up to three additional projects to implement the incentive pilot. A distribution planning advisory group, supported by an independent professional engineer, shall review and provide feedback to utilities on distribution projects to be deferred or displaced. The distribution planning advisory group will be open to market participants, except for instances when market sensitive material such as the costs of the alternative conventional solutions are being discussed. Each proposal will go through a quantitative evaluation that will consider among other things project's net market value, distribution and transmission deferral value, reduced GHG emissions benefit and contract payment costs as well as a qualitative evaluation that will consider factors such as voltage and other power quality services, suppler and site diversity.

Utilities will then file an advice letter with the PUC requesting commission's approval to procure a DER solution for the project or projects selected. After PUC's approval, the solicitation process will follow. A separate group, called procurement review group also supported by the independent Engineer will review the solicitation bids. Finally, the PUC should approve the contracts for the Incentive Mechanism pilot(s), after the review by this group.

6.2.2 Regulatory Incentive Pilot Plan

The cost of annual payments to the DER providers as well as utilities' administrative costs for solicitation process shall be considered pre-approved for recording in a deferral account and recovered in the next general rate case. Any administrative cost in excess of PUC approved forecast will be subject to a reasonableness review.

The utilities may receive positive earning incentives in two ways:

- Similar to REV, utilities will be able to retain any saving from deploying less costly DER alternatives in lieu of the previously-authorized distribution projects until the next general rate case. That is any previously authorized distribution capital spending is only reviewed in the next general rate case, when the recorded rate base is trued up.
- For the purposes of utility regulatory incentive pilot plan, PUC adopted a four percent pre-tax incentive applied to the annual payment to the DER providers. The incentive would be recoverable if the DER procured were successful in avoiding or deferring an otherwise planned utility expenditure. Once deferral period ends and a traditional investment is made, no incentive shall be recovered for that year and going forward. The utilities are allowed to record the value of the incentive in a balancing account for later recovery.

Using the data from the completed projects and in order to assess pilot plan's incentive mechanism against other incentive models, utilities' incentive pilot plan report shall include a financial analysis of the impacts on the utilities, customers and vendors from the following incentive mechanism:

(i) percent of investment incentive as approved

(ii) percent of incentive applied to the counterfactual conventional investment and

(iii) shared savings.

Appendix C4-3

FUNDAMENTALS OF RATE SETTING

FUNDAMENTALS OF RATE SETTING

1. INTRODUCTION

A basic knowledge of the fundamentals of the common rate-setting mechanisms is a prerequisite for understanding FortisBC's Application and will assist the reader to recognize the overall benefits and challenges of MRPs compared to alternative forms of regulation.

This document strives to provide a concise and practical description of the two most common rate-setting mechanism: rate base rate-of-return regulatory framework (also known as cost of service regulation) and multi-year rate plans commonly referred to as I-X mechanisms[1].

2. COST OF SERVICE REGULATION

Under the traditional cost of service regulation, 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 interest, and return on equity). The revenue requirement also includes taxes payable to various levels of government such as income taxes and property taxes. The company's debt and equity are used to finance the company's assets (wires, pipes, etc.) used to provide utility service, which are referred to as its rate base. 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.

In the second phase of a rate application, rates to be paid by individual customers for services received through the utility's 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.

In FortisBC Energy Inc.'s (FEI) and FortisBC Inc.'s (FBC) revenue requirement proceeding and in many other Canadian jurisdictions, all of these determinations are made on a forecast basis, generally for two years[2]. So, for example, a company could file a rate application for the two

[1] For the sake of efficiency and in order to provide an independent review, the majority of the material in this section is based on AUC's 2012-237 decision with minor changes or addition where appropriate.

[2] It should be noted that in some US jurisdictions, the use of historical and/or mix of historical and forward test years in cost of service regulation is still common. The capital tracker mechanisms in these jurisdictions are often used to

years 2020 and 2021. A forecast revenue requirement would be provided by the company for each of the two years, called test years. The regulator 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 company's plans and expectations over the two test years. When new rates are implemented for the two years, the company begins to collect them from customers 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.

If the company is able to provide service for less than it had forecast during the previous two years, or if billing units are greater than were forecasted, the company is generally permitted to keep the extra revenues or cost savings as extra profit in those years[3]. 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. In the hearing process for the next two years, the regulator will also evaluate the reasons that the variances from forecast occurred in the prior years and may make determinations that improvements are required in the company's processes for forecasting costs and revenues. 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.

While this regulatory model is relatively straightforward in its conception, it produces some incentives and disincentives that are widely recognized. For instance, 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 is ordinarily 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, some have argued that 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.

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recover the costs of accelerated main replacement programs to compensate these utilities during the cost of service period or while their future revenue requirement is still under review.

[3] In some cases, based on previous determinations of the regulator, cost and revenue variances of certain types are subject to true-up mechanisms, such as deferral accounts, and, if so, the utility does not gain or lose from variances in those categories

Further, cost of service regulation is much more prescriptive and therefore requires much more regulatory scrutiny which leads to higher regulatory costs and less regulatory efficiency.

3. ALTERNATIVE TO COST OF SERVICE REGULATION

Starting in 1980s a new form of regulation named "I-X" regulation was developed. Multiple variations of this regulation is currently used all over the world and known by various names such as incentive regulation (IR), multi-year rate plan (MRP), Index-based regulation (IBR), attrition relief mechanism (ARM), performance-based regulation (PBR)[4].

A basic index-based multi-year rate plan begins with rates/revenues established through a cost of service proceeding where the base year costs are determined. Those rates/revenues are then adjusted in subsequent years by a rate of inflation (I) relevant to the prices of inputs the company uses less an offset (X) to reflect the productivity improvements the company can be expected to achieve during the PBR plan period. Thus, adjusting rates by I-X, rather than through the forecasts used 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 plan will depend on how its own performance compares to the industry's inflation and productivity measures.

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 earnings generated by those cost reductions for a longer period 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 this regulatory framework, customers automatically benefit from the expected productivity gains embedded into rates through the productivity factor regardless of the actual performance of the companies.

However not all cost items can be covered by the I-X mechanism. PBR plans typically include a mechanism for treatment of unanticipated cost increase or decreases caused by exogenous and non-controllable factors. This mechanism can be used to increase or decrease the company's rates to reflect cost changes caused by company-specific events. 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.

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

[4] Sometimes PBR regulation refers to more than use of I-X formulas and cost reduction and includes reward and/or penalty mechanism attached to utility's output and performance. These are sometimes referred to as performance incentive metrics or PIMs.

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. 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.

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. Regulators recognize 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.

Regulators usually support the adoption of MRPs as they can make the regulatory system more efficient over time as the regulator, interveners and companies become more familiar with it. At the same time the regulators expect that, under MRPs, customers will experience lower rates than they would have had if the cost of service framework had continued unchanged.

3.1 *MAJOR CATEGORIES OF INDEXED MRPS*

The indexing formulas can be categorized in various ways. These include the revenue cap model versus the price cap model and/or the Totex approach versus the building block approach. Custom made MRPs are also possible.

3.1.1 Price cap model

Price cap formula adjusts the utility’s prices according to the price cap index that reflects the overall rate of inflation in the economy and the expected industry productivity growth. Under price cap formula the rates for each customer class is computed as:

$$\text{Rates}_{t} = \text{Rates}_{t-1} * (1 + I - X) \pm \text{Other Adjustments}$$

Where:

I = Inflation factor;

X = Expected industry productivity growth

The inflation factor in this formula can be set based on forecast or historical data. Further the inflation factor can be set as a single inflation index such as CPI or GDP/IPIFDD or be a composite of two or more factors (ordinarily one labour inflation index and one on-labour inflation index). The X-factor can be fixed for the entire MRP term or it can change annually. 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 the use of price caps can be problematic when there is expected to be a continuing decline in sales per customer. Use of price cap has been more common for electric utilities and usually not used for natural gas utilities.

3.1.2 Revenue cap model

Revenue cap regulation is similar to price cap regulation in that the regulator approves an I - X index, which in this case is called a revenue cap index, for service baskets and allows the utility to change prices within the basket so long as the percentage change in revenue does not exceed the revenue cap index. Revenue cap regulation is more appropriate than price cap regulation when utilities collect most of their revenues from volumetric charges, and average energy usage per customer is declining; and/or to promote energy conservation and demand-side resource goals. The following is an example of revenue per customer class cap:

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

Rates $_t$ = Revenue per customer $_t$ / billing determinant for each customer class $_t$

3.1.3 Totex vs building block approach:

Another way of categorizing the indexing formulas is based on the costs they cover. Under a building-block approach, the O&M expenditures (Opex) and capital expenditures (Capex) are assessed separately, and in some cases the Capex expenditures are treated outside the (I – X) mechanism. Under the total expenditure approach (also known as Totex), Opex and Capex are summed up and all expenditures are subject to one formula[5]. Totex and the building-block approaches lead to equal results if the productivity improvement factor and the expenditures covered under the formula are the same, other things being equal.

3.1.4 Custom models

In addition to the models above, custom models of incentive regulation also exist. FortisBC's current MRPs are good examples. In their core, FortisBC plans can be categorized as a hybrid of revenue cap and building block approaches with elements of cost of service regulation as they ultimately cap the revenue, the formulas for capital expenditures are separated from O&M formula and certain costs are treated under cost of service rate-setting. However unlike the

[5] Sometimes like the case in OFGEM's RIIO, Totex approach is applied by fixing the ratio between the capital and O&M.

revenue cap plans in other jurisdictions, FEI and FBC's plans escalate O&M expenses and certain capital expenditures with separate formulas that are based on inflation and the growth factor less a productivity factor. FBC has one formula applying to all untracked capex. This formula features the number of customers as the growth factor. FEI has one formula for growth capex and a second formula for sustainment and other untracked capex. These use the service line additions and the number of customers, respectively, as the growth factor. Capital costs for projects that are larger, more unusual in nature, and less predictable are treated outside the I-X mechanism, along with the cost of all older plant.

Each year the Companies' rates are revised to reflect the cost growth resulting from the formulas and other cost items not subject to formulas through an annual review process. In these reviews, both formula-based plant additions and CPCN-related plant additions are added to the rate base. Actual plant additions are fully reflected in the rate base only in the rebasing at the end of the plan. The rate base is also updated in these proceedings to reflect the falling value of old plant due to depreciation. By including the impact of depreciation of the existing rate base, the impact of capex on the revenue requirement is lessened substantially. This is big divergence from revenue and price cap plans where the depreciation expense is subject to I – X mechanism as well.

3.1.5 Project-specific incentive plans

Custom made incentive plans can be project specific. The project specific incentive plans are often designed to promote certain government policies such as increased use of distributed generation. The Brooklyn Queens Demand Management (BQDM) project in New York is a recent example. The BDQM project was designed to address load growth needs of customers through a combination of traditional utility capital investments and unconventional non-wire solutions, such as the use of distributed energy resources (DER). To ensure that the utility is indifferent to investments in DER and traditional infrastructure investment with higher rate base growth potential, the New York's Public Service Commission approved several unique financial incentives:

- Return on total expenditure at allowed ROE
- Amortization period of expenses reduced to 10 years
- 100 bps premium over the authorized return tied to metrics related to achieving the outcomes as follows: (i) 45 bps for achieving the proposed 41 MW of alternative measures (ii) 25 bps for increasing the diversity of DER in the market place; that is company will earn more by contracting with more DER providers with smaller market share (iii) 30 bps for company's ability to assemble a portfolio of solutions that achieves lower $/MW value than the traditional investment solutions presented.

The regulators in New York may consider these kind of project specific incentives as part of their larger effort to reform State's energy vision to promote more distributed energy and move away from centralized approach.

FERC[6]'s incentive policies for transmission investment projects is another example. The Energy Policy Act of 2005 directed the regulator to develop incentive-based rate treatments for transmission of electric energy in interstate commerce, adding a new section to the Federal Power Act. The rule implemented this new statutory directive through the following incentive-based rate treatments:

- Incentive rates of return on equity for new investment by public utilities (both traditional utilities and stand-alone transmission companies, or transcos);
- Full recovery of prudently incurred construction work in progress;
- Full recovery of prudently incurred pre-operations costs;
- Full recovery of prudently incurred costs of abandoned facilities;
- Use of hypothetical capital structures;
- Accumulated deferred income taxes for transcos;
- Adjustments to book value for transco sales/purchases;
- Accelerated depreciation;
- Deferred cost recovery for utilities with retail rate freezes; and
- A higher rate of return on equity for utilities that join and/or continue to be members of transmission organizations, such as (but not limited to) regional transmission organizations and independent system operators.

All rates approved under the rules are subject to Federal Power Act rate filing standards. The rule allows utilities on a case-by-case basis to select and justify the package of incentives needed to support new investment. Additionally, the rule provides expedited procedures for the approval of incentives to provide utilities greater regulatory certainty and facilitate the financing of projects.

[6] Federal Energy Regulatory Commission

Appendix C5

SERVICE QUALITY INDICATOR REPORTS

Appendix C5-1

FEI SERVICE QUALITY INDICATORS

FEI SERVICE QUALITY INDICATORS

1. INTRODUCTION

Maintaining a high level of service quality is important to the long-term success of the Company. In support of this, and as in the 2014 to 2019 PBR Plan, FortisBC Energy Inc. (FEI or the Company) proposes a suite of Service Quality Indicators (SQIs) be established as part of the proposed Multi-year Rate Plan (MRP). The SQIs will serve to ensure that service quality to our customers is maintained at acceptable levels throughout the term of the MRP Period.

FEI proposes a suite of SQIs which builds on its experience. In the following sections, the criteria for SQI selection, the SQI's history and development at FEI, as well as proposed updates and modifications are discussed. These SQI metrics reflect a broad range of business processes that are important elements of the customer experience.

2. SERVICE QUALITY INDICATORS CRITERIA, BENCHMARKS, THRESHOLDS, AND HISTORY

2.1 *SERVICE QUALITY INDICATORS SELECTION CRITERIA*

In developing the proposed suite of Service Quality Indicators for the current Application, the criteria used to establish the SQIs for the past PBR plans in 1998, 2004 and 2014 were considered, as FEI believes that the criteria are still appropriate. The criteria are presented in Table A:C5-1-1 below.

Table A:C5-1-1: 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 actions of the Company's employees have little or no influence.
3	Cost effective	The information collection activities associated with the indicator must be cost effective.
4	Simple and transparent	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	Flexible	The indicators should allow sufficient flexibility to allow modifications, additions and deletions as required over time.

2.2 *CHOICE OF BENCHMARKS*

Benchmarks are reference points against which levels of service quality can be compared. The objective of SQIs is to ensure that the Company continues to provide an "acceptable level" of service at an "acceptable level" of cost to our customers. Therefore, in setting SQI benchmarks, it is necessary to consider whether customers are willing to pay for additional improvements in the indicators, as incremental costs for achieving further improvements increase as the limit of the indicator is approached. Benchmarks typically reflect either industry standards or the Company's performance over recent prior periods.

2.3 *THRESHOLDS AND SATISFACTORY PERFORMANCE RANGES*

Thresholds or satisfactory performance ranges were introduced in the 2014 PBR Plan as an effective way to manage SQIs. In 2014, the BCUC in Order G-138-14 regarding FEI's 2014-2018 Multi Year PBR Application agreed that it was not appropriate to require FEI to be held to a specific performance benchmark. The BCUC stated:

> The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases, a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks, it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.**

Through a consultative process with stakeholders, FEI and stakeholders reached an agreement titled the "Consensus Recommendation" on appropriate thresholds to consider. In BCUC Order G-14-15 dated February 4, 2015, the Consensus Recommendation was approved.

2.4 *HISTORY AND DEVELOPMENT OF SERVICE QUALITY INDICATORS AT FEI*

In the 1998 PBR Settlement, five service quality indicators were agreed to. The 2004 PBR Settlement continued with the use of three SQIs from the 1998 PBR Settlement, changed the status of two SQIs to directional indicators, and added eight new SQIs to assess the Company's performance. The 2014-2019 PBR Plan refined the definition of two existing SQIs, renamed one, continued with five existing SQIs, and added five new SQIs.

Table A:C5-1-2 following outlines the history and evolution of FEI's SQIs over the four eras (1998 PBR, 2004 PBR until 2012-2013 RRA, 2014 PBR and the proposed 2020 MRP.

1 **Table A:C5-1-2: History and Evolution of SQIs at FEI (1998 - 2020)**

ID	Service Quality Indicator	1998 PBR	2004 PBR till 2013	2014 PBR	2020 MRP
1	Emergency response time	Included (Only coastal region)	Included (Interior region was added)	Revised definition of emergency response time	Included
2	Telephone service factor - Emergency	Included (Only coastal region)	Included (Interior region was added)	Included	Included
3	Telephone service factor – Non-emergency	Not available[1]	Included (for interior and coastal regions)	Included	Included
4	Transmission reportable incidents	Included	Included	Included	Included
5	Index of customer bills not meeting criteria	Not applicable	Included	Included (Renamed to Billing Index)	Included
6	Percent of industrial customer bills accurate	Not applicable	Included	Discontinued	Discontinued
7	Meter exchange appointment activity	Not applicable	Included	Included	Included
8	Accuracy of transportation meter measurement first report	Not applicable	Included	Discontinued	Discontinued
9	Independent customer satisfaction survey	Not applicable	Included	Replaced with "customer satisfaction Index"	Included
10	Number of customer complaints to BCUC	Not applicable	Included	Discontinued	Discontinued
11	Number of prior period adjustments	Not applicable	Included	Discontinued	Discontinued
12	Leaks per Km of distribution system mains	Included	Included (only as directional indicator)	Included	Included
13	Number of 3rd party distribution system incidents	Included	Included (only as directional indicator)	Discontinued	Discontinued
14	First contact resolution (FCR)	Not applicable	Not applicable	New customer service SQI	Included
15	Meter reading accuracy - number of scheduled meters read	Not applicable	Not applicable	New meter reading SQI	Included
16	All injury frequency rate	Not applicable	Not applicable	New safety SQI	Included
17	Public contacts with pipelines	Not applicable	Not applicable	New safety SQI	Included
18	Telephone Abandon rate	Not applicable	Not applicable	New customer service SQI	Replaced with Average Speed of Answer

[1] BC Hydro answered the majority of non-emergency inquiries prior to repatriation in 2002.

For the 2020 MRP Plan, FEI reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to our customers is maintained at acceptable levels throughout the term of MRP. For some SQIs, FEI proposes to change their benchmarks, recognizing their recent historical performance. Additionally, FEI proposes to replace the existing Telephone Abandonment Rate with the Average Speed of Answer. In the following sections, FEI provides discussion of the proposed SQIs, their benchmarks and thresholds.

3. PROPOSED SERVICE QUALITY INDICATORS AND BENCHMARKS

3.1 *SAFETY SERVICE SQIs*

3.1.1 Emergency Response Time

Emergency response time is included in the current set of SQIs and measures the utility's responsiveness to on average 25,500 annual emergency events that include gas odour calls, carbon monoxide calls, house fires and hit lines. It is calculated as:

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

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events, available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The current benchmark was set by the BCUC at 97.7 percent based on the average of FEI's annual results from 2010 to 2012. The following table summarizes the historical percentage of emergency events responded to within one hour results since the start of the current PBR Plan compared to the approved benchmark and threshold. Provided also are FEI's proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-3: Results during the PBR Plan for Emergency Response Time

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Emergency Response Time	96.7%	97.3%	97.4%	97.8%	97.8%	97.7%	97.7%	96.2%	96.2%

Table A:C5-1-4 below provides details of the emergency activity levels (number of calls), average emergency response times, the number of calls greater than one hour, and the overall percentage of emergency response times one hour or less.

Table A:C5-1-4: Summary of FEI emergency activity levels and average response time (in minutes)

		CGA type Emergency[2]	Number of calls over one hour	Percent of response one hour or less
2014 to 2018	Number of calls	119,665	3,121	97.4%
	Average response time	20.49		
2018	Number of calls	23,146	518	97.8%
	Average response time	20.13		
2017	Number of calls	26,084	586	97.8%
	Average response time	20.31		
2016	Number of calls	23,227	617	97.4%
	Average response time	20.37		
2015	Number of calls	23,356	640	97.3%
	Average response time	20.55		
2014	Number of calls	23,852	763	96.7%
	Average response time	21.09		

The response time since 2014 has improved in all operation zones, a reflection of a combination of factors including changes made to technician shift schedules starting January 2015. The changes to shift schedules were made to provide more emergency response capacity in the late afternoon and early evening. The average of FEI's annual results from 2016 to 2018 (i.e., 3 year average of recent actual results methodology used by the BCUC for the current PBR Plan) is 97.7 percent which is the same as the existing approved benchmark of 97.7 percent.

FEI proposes to continue to report on Emergency Response Time. Additionally, FEI believes the current benchmark represents the level of service expected by its customers and is appropriate and proposes to retain its existing benchmark and threshold for the term of the proposed PBR Plan.

3.1.2 Telephone Service Factor (Emergency)

Telephone service factor (TSF) is a measurement of the percentage of calls answered within a defined window of time. FEI has reported the speed of answer for both emergency and non-

[2] Following items are included in CGA emergency: Gas odour upstream and downstream, gas odour – industrial, gas odour – other, fires and explosion, CO investigation, mains hit lines, services hit lines, meter/station.

emergency calls. Non-emergency calls include those related to bill inquiries, service applications and calls general in nature and are discussed in Section 3.2.4

The TSF (Emergency) measures the percentage of emergency calls answered within 30 seconds and is calculated as:

$$\frac{\text{Number of emergency calls answered within 30 seconds}}{\text{Number of emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels, with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include the volume of inbound calls received and the resources available to answer those calls. Staffing is matched to the calls forecast based on historical data in order to reach the service level benchmark desired.

Following is a summary of the historical results for TSF (Emergency) since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 PBR.

Table A:C5-1-5: Results during the PBR Plan for Telephone Service Factor (Emergency)

Type of Call	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Emergency	95.8%	97.6%	98.5%	97.6%	97.9%	95%	95%	92.8%	92.8%

The results from 2014 to 2018 were better than the benchmark of 95 percent approved by the BCUC.

FEI proposes to continue to report on TSF (Emergency) and retain the existing benchmark and threshold for emergency calls. FEI believes that the proposed benchmark reflects an appropriate balance between cost and service level, and that customers are satisfied with the level of service being provided.

3.1.3 All Injury Frequency Rate

FEI is committed to continual improvement of corporate safety performance and will report employee safety performance as part of the Company's SQI profile using the metric All Injury Frequency Rate (AIFR). The reduction of work stoppage and efficiency losses as a result of safety incident reduction will promote productivity enhancements across the Company.

The AIFR is a comprehensive safety performance indicator based on lost time injuries (LTI) plus medical treatment injuries (MT) per 200,000 hours worked (approximately injuries per 100 workers). LTIs are injuries that result in one or more days missed from work. MTs are injuries where medical treatment was given or prescribed beyond medical aid and observation, and no lost time was involved.

The following formula is used:

All Injury Frequency Rate =

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

(Denominator: Exposure Hours[3])

For the purpose of this SQI, the measurement of performance is based on the three year rolling average of the annual results.

Following is a summary of the FEI's AIFR annual and three year rolling average results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-6: Results during the PBR Plan for AIFR

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
AIFR – three year rolling average	2.22	2.42	2.13	2.00	1.74	2.08	2.08	2.95	2.95
AIFR – annual	1.73	2.52	2.13	1.36	1.74	n/a	n/a	n/a	n/a

The results from 2014 to 2018 have been between the threshold and the benchmark, with 2017 and 2018, better than the benchmark approved by the BCUC. The current benchmark was set by the BCUC at 2.08 based on the average of results from 2010 to 2012.

Safety continues to be a core value for FEI and prevention of injury remains a key focus. FEI continues to focus on and reinforce the fundamentals of safety through effective safe work planning identifying hazards and mitigating risks, detailed work observations and thorough event analysis capturing learning and identifying opportunities for continued improvement. Target Zero is a program which was launched in January 2016. This program focuses on a number of key elements designed to enhance the existing safety management system and engage employees at all levels in safety as well as promote an interdependent safety environment. The Company believes this program has contributed to the positive safety trend experienced during the current PBR Plan.

[3] Exposure hours reflect actual hours worked excluding time off for vacation, statutory holidays, sickness, etc.

FEI remains committed to maintaining its focus on safety. FEI believes that the current benchmark and threshold remains appropriate for the term of the proposed MRP as the Company assesses the trend and sustainability of recent years' performance.

3.1.4 Public Contacts with Gas Lines

FEI recognizes the importance of public safety. A key area of public safety is contact with buried pipelines. To measure performance in this area, FEI has been using of the metric Public Contacts with Pipelines, which reflects the number of line damages per 1,000 BC One Calls received. The Company places significant attention on educating the public of the risk associated with gas line contact. This SQI will measure the overall effectiveness of the public's awareness to minimize damage to the gas system, which will reduce risk to public safety and service interruptions for customers.

Principal factors influencing results for this metric include economic growth (i.e., construction activity), damage prevention awareness programs and heightened public awareness created by the BC One Call program. The recent three year rolling average results reflect an ongoing positive trend for this metric. Increased awareness through targeted workshops with municipalities and excavating contractors, together with a higher number of calls generated by the BC One Call program have contributed to the improved performance.

Following is a summary of the FEI's Public Contacts with Gas Lines annual and three year rolling average results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-7: Results during the PBR Plan for Public Contact with Gas Lines

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Public Contact with Gas Lines – three year rolling average	11	9	9	8	8	16	n/a	16	n/a
Public Contact with Gas Lines – annual	9	8	8	9	8	n/a	8	n/a	12

The results from 2014 to 2018 have been better than the benchmark approved by the BCUC. The current benchmark was set by the BCUC at 16 based on the average of results from 2010 to 2012. The annual result has been trending downward as has the three year rolling average. This is due to the historical upward trend in BC One Calls (increased awareness and increased construction activity), offset by an increase in the number of line damages resulting from increased construction activities.

FEI proposes to continue to report on Public Contacts with Pipelines and for clarity, replace the word "Pipelines" with the words "Gas Lines". Based on the improved performance in recent years which the Company believes is sustainable, FEI proposes to lower the benchmark from the existing 16 to 8. FEI proposes also to revise the basis for the actual results reported from the current three-year rolling average approach to a current year only approach. A current year results focus approach is a clearer indicator of the Company's performance in a given year than one based on a three year rolling average. Additionally, a current year results focus is generally easier to understand.

The Company proposes to lower the threshold to 12 reflective of historical performance observed.[4] While performance has improved in recent years, FEI highlights historical results have been higher and provide an objective basis to set a satisfactory performance range.

3.2 RESPONSIVENESS TO CUSTOMER NEEDS SQIS

3.2.1 First Contact Resolution (FCR)

First Contact Resolution (FCR) is an area of focus for FEI as research conducted suggests that it is the single most important driver of customer satisfaction. By maintaining a high level of FCR, the Company can effectively satisfy customers who are looking to have their issues resolved effortlessly.

FCR measures the percentage of customers who receive resolution to their issue in one contact with FEI. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

Following is a summary of the FCR results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-8: Results during the PBR Plan for First Contact Resolution

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
First Contact Resolution	80%	81%	81%	80%	83%	78%	78%	74%	74%

The results from 2014 to 2018 have been better than the benchmark approved by the BCUC. The current benchmark was approved by the BCUC at 78 percent based on setting a target that was above the industry average for call centre performance.

4 Annual results reported; 2010 – 18; 2011 – 16; 2012 – 13; 2013 - 10

FEI proposes to continue to report on FCR and retain the existing benchmark and threshold.

3.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing processes by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the 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 objective is to achieve a score of five or less.

The relevant formulas and benchmarks for the three sub-measures are presented below.

Table A:C5-1-9: The Benchmarks and Formulas for Calculation of Billing Index SQI

Billing sub-measure	Percent achieved (PA)	Adjustment	Result
Percentage of bills accurate based upon input data	99.9%	* See formula below	5.0
Percentage of bills delivered to Canada Post within two days of date that the statement file is created	95%	(100% - PA)*100	5.0
Percentage of customers billed within two business days of the scheduled billing date	95%	(100% - PA)*100	5.0
Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			5.0

* IF [PA ≥ 99.9%, 5000 * (1 - PA), 100 * (1.05 - PA)]

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues.

Following is a summary of the Billing Index results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-10: Results during the PBR Plan for Billing Index

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Billing Index	0.89	1.06	0.57	0.75	2.63	5.0	3.0	5.0	5.0

The results from 2014 to 2018 have been better than the benchmark approved by the BCUC. No significant billing issues have arisen over the period.

FEI proposes to continue to report on the Billing Index as the Company believes that customers value complete, timely and accurate bills. Reflective of the recent historical performance and efficiencies achieved by the Company in producing bills, FEI proposes to lower the benchmark from 5.0 to 3.0 and to maintain the threshold at 5.0.

3.2.3 Meter Reading Accuracy – number of scheduled meters that were read

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

Factors influencing this SQI's performance include the resources available, system issues impacting the Company's billing or reading collections systems, weather conditions including road and highway conditions and traffic related issues. In 2013, in order to address customer concerns related to billing accuracy, the Company moved to monthly meter reading instead of bi-monthly. The Company currently reads meters monthly (approximately 984,000 meters), including the majority of customer move reads and special reads required in response to billing inquiries (estimated at 63,350 annually).

Table A:C5-1-11: Results during the PBR Plan for Meter Reading Accuracy

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Meter Reading Accuracy	97.0%	97.5%	96.9%	96.2%	95.4%	95%	95%	92%	92%

The results from 2014 to 2018 have been consistent and better than the benchmark approved by the BCUC.

FEI proposes to continue to report on the Meter Reading accuracy metric given the value customers place on receiving a timely and accurate bill. FEI proposes to retain the existing benchmark and threshold.

3.2.4 Telephone Service Factor (Non-Emergency)

Telephone service factor (TSF) is a measurement of the percentage of calls answered within a defined window of time. Historically, FEI has reported the speed of answer for both emergency and non-emergency calls.[5]

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

Similar to the TSF (Emergency), this is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the non-emergency TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

Following is a summary of the historical results for TSF (Non-Emergency) since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-12: Results during the PBR Plan for Telephone Service Factor (Non-Emergency)

Type of Call	2014[6]	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Non Emergency	75%	71%	71%	71%	71%	70%	70%	68%	68%

The results from 2014 to 2018 were consistent with the benchmark of 75 percent to 2014 and the revised benchmark of 70 percent approved by the BCUC in mid-September 2014. Results in 2015 and subsequent years were reflective of the revised target of 70 percent.

FEI proposes to continue to report on TSF (Non-Emergency) and retain the existing benchmark and threshold for non-emergency calls.

[5] Refer to Section 3.1.2 discussion of TSF (Emergency).
[6] The 2014 result was achieved with the Company targeting 75 percent as the benchmark.

3.2.5 Meter Exchange Appointment Activity

This indicator tracks the percentage of appointments met for meter exchanges (excluding industrial meter exchanges). The meter exchanges are required to be done under regulations from Measurement Canada and are generally completed in less than an hour including travel time. The gas is shut off, the in-service meter is exchanged for a new meter, the gas is turned on and the technician locates and relights the customer's appliances. The appointment is necessary as the technician requires access to the inside of the premise to perform the relights to the gas appliances.

The calculation for percentage meter exchange appointments met is calculated as:

$$\frac{\text{Number of meter exchange appointments met}}{\text{Number of meter exchange appointments made}}$$

Factors influencing results include process improvements, number of emergencies, weather and traffic conditions. The process improvements initiated in recent years have resulted in the contact center and operations departments working more closely together in order to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

Following is a summary of the historical results for Meter Exchange Appointment since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-1-13: Results during the PBR Plan for Meter Exchange Appointment Activity

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Meter Exchange Appointment Activity	95.0%	96.6%	96.9%	97.0%	96.3%	95.0%	95.0%	93.8%	93.8%

The results from 2014 to 2018 were consistent and mostly higher compared to the benchmark of 95 percent approved by the BCUC. FEI values customers' time and strives to meet customers' expectations with regard to commitments it makes to perform scheduled work at their premises.

FEI proposes to continue to report on the Meter Exchange Appointment metric and retain the existing benchmark and threshold.

3.2.6 Customer Satisfaction Index (CSI)

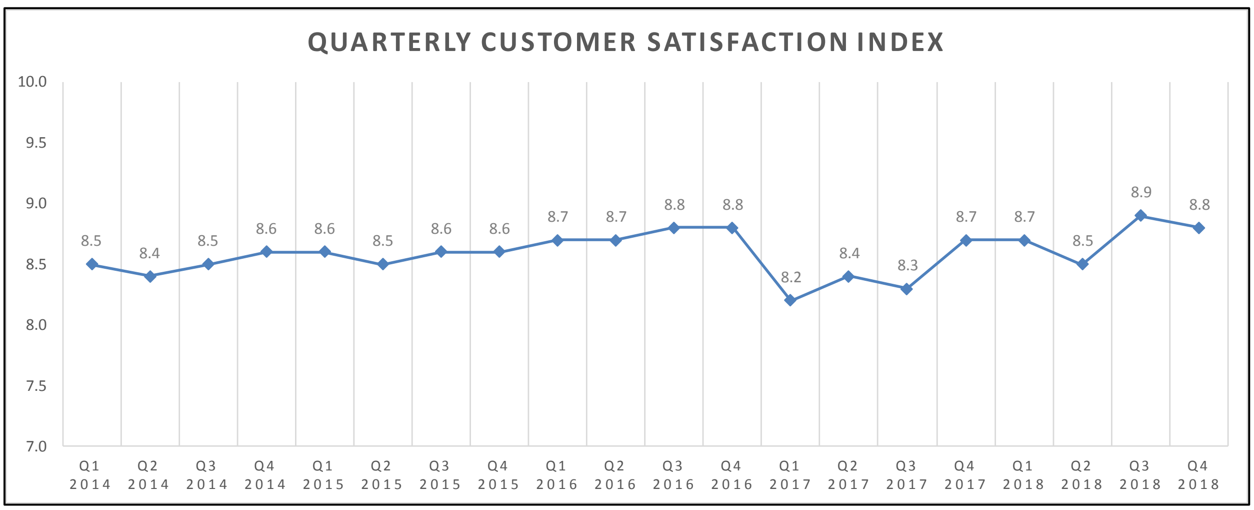
Since 2013, FEI has used the Customer Satisfaction Index (CSI) to assess overall customer satisfaction with the company's natural gas service. The CSI score gathers quarterly feedback from customers, using the same strategy to survey both residential and mass market commercial customers. In addition to covering service touch points such as contact centres and field services, it also evaluates how customers view the Company across a range of other service attributes.

The CSI survey is conducted quarterly involving 600 telephone interviews with customers. Lists of active customers are provided to an external research vendor. The research vendor uses quota sampling to ensure 500 interviews are residential customers, and 100 are mass market commercial customers (Rate Schedule 2).

The index is based on responses to several questions employing a 10 point scale (i.e., top four box answers 7-10). Index contributors include: (1) overall satisfaction with natural gas service from FortisBC; (2) satisfaction with the accuracy of meter reading; (3) satisfaction with energy conservation information; (4) overall satisfaction with the contact centre; and (5) overall satisfaction with field services.

The graph below shows CSI results since 2014.

Figure A:C5-1-1: CSI Results



FEI proposes to continue using this metric as an informational service quality indicator. Results are considered informational in nature and consideration should be given to external factors that can influence customer satisfaction scores. This includes the price of natural gas which is an exogenous factor and can have an adverse influence on customer satisfaction.

FEI is planning to review the CSI index scoring and methodology. Customers' needs and wants change over time, as do their service expectations. The purpose of reviewing the index is to ensure we are measuring the factors that customers have identified as important to them in the current environment. FEI proposes continuing with the current CSI measure and calculations while this review occurs.

3.2.7 Telephone Abandonment Rate

The Telephone Abandon Rate is an informational indicator that measures the percent of calls abandoned by the customer before speaking to a customer service representative. Abandon rates can be due to waiting times, or due to customers receiving their required information through informational messages in the Company's Interactive Voice Response (IVR) system such that the customer no longer needs to speak to an agent.

Following is a summary of the historical results for Telephone Abandonment Rate since the start of the current PBR Plan.

Table A:C5-1-14: Results during the PBR Plan for Telephone Abandonment Rate

Description	2014	2015	2016	2017	2018
Telephone Abandonment Rate	1.8%	2.0%	2.2%	1.9%	2.0%

The results from 2014 to 2018 have been stable and generally consistent from year to year.

FEI proposes to replace the existing metric with another Informational Indicator, Average Speed of Answer (ASA).

FEI does not believe the Telephone Abandonment Rate is indicative of whether customer needs are being met. While assumptions can be made about why a call is being abandoned based on when it is abandoned, there is really no way to know why a customer abandoned a call, absent asking the customer directly. There may be positive reasons why a customer abandoned a call without talking to a customer service representative (e.g. they receive the information they were looking for from the recorded IVR message). The reasons may also be related to what is perceived to be a negative customer experience. Therefore, it is not possible to conclude with any certainty what the trends in the Telephone Abandonment Rate relate to.

FEI believes the ASA is more directly related to the customer experience, with shorter wait times for customers preferable to longer wait times. FEI is also better able to analyze trends in this metric, as wait times at certain times on certain days can be isolated and explained in terms of staffing levels, unexpected absences, technology issues, etc.

To provide context, the table below shows FEI's ASA (in seconds), for the last five years. These figures show, for example, that ASA for emergency calls has continued to decrease since 2014 (with the exception of 2017).

Table A:C5-1-15: FEI Average Speed of Answer (2014 – 2018) in seconds

Description	2014	2015	2016	2017	2018
Combined	34.05	36.70	39.62	33.97	35.23
Emergency	11.64	8.46	8.32	8.75	7.46
Non-Emergency	35.62	38.91	42.52	36.49	37.58

3.3 *RELIABILITY SQIs*

3.3.1 Transmission Reportable Incidents

The Transmission Reportable Incidents metric, an informational indicator as approved by the BCUC, measures the number of reportable incidents to outside agencies for transmission assets as defined by the Oil and Gas Commission (OGC). The metric is intended to be an indicator of the integrity of the transmission system.

Prior to the third quarter of 2014, the practice was to report only on the higher pressure transmission events designated as serious. However, the OGC put in place new reporting criteria effective October 1, 2014, which required the Company to report on more incidents and events. As of October 1, 2014, the Company reports Transmission Reportable Incidents based on the new OGC reporting criteria, including Level 1, 2, and 3 reportable incidents for both transmission and intermediate pressure assets that operate at a pressure exceeding 100 psi. This includes pipelines, mains, services, stations, LNG plants and compressor stations, but excludes distribution assets that operate below 100 psi. The change in the OGC reporting criteria limits the comparability of historical performance data for this metric.

The following table summarizes the transmission reportable incidents from 2014 to 2018 by severity level.

Table A:C5-1-16: Transmission Incidents by Severity Level during the current PBR Plan

OGC Security Level	Number of Reportable Incidents				
	2014	2015	2016	2017	2018
Level 1 (moderate)	1	3	3	4	2
Level 2 (major)	1	0	0	0	0
Level 3 (serious)	0	0	0	0	0

In 2018, there were two Level 1 reportable incidents.

- The first Level 1 incident took place in April 2018 when a mud slide struck and exposed a Transmission Pipeline near Castlegar. The pipeline was dented and will require repair.
- The second Level 1 incident involved pipe along a section of river in the Falkland Valley that was exposed due to erosion. The potential for erosion was reported by patrols in

> April and May. The Company waited for water levels to recede in June before it could inspect and confirm the erosion.

FEI proposes to continue to report Transmission incidents as an informational indicator.

3.3.2 Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator approved by the BCUC that measures the number of leaks on the distribution system per KM of distribution system mains. The metric is intended to be an indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system is surveyed for leaks, with the number of leaks varying from year to year, depending on the condition of the pipe surveyed.

Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system as some sections of the pipeline system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline. As the distribution system ages, the expected number of leaks may increase depending on the Company's pipeline renewal/replacement activities. Increases in leak survey activity levels will generally also result in a higher number of leaks detected.

In its Decision on FEI's Application for the Annual Review of 2015 Delivery Rates, the BCUC directed FEI to provide a five-year rolling average as follows:

> The Panel agrees with BCSEA that a five-year rolling average of Leaks per KM of Distribution System Mains would be helpful information and directs FEI to provide this information in future annual reviews.

The Company's 2014 to 2018 annual and five-year average results are provided below.

Table A:C5-1-17: Historical Leaks per KM of Distribution System Mains during the current PBR Plan

Leaks per KM of Distribution System Mains	2014	2015	2016	2017	2018
Leaks	114	102	107	108	140
Total km	19,172	22,602	22,813	22,951	23,060
Leaks per km	0.0059	0.0045	0.0047	0.0047	0.0061
5 year average	0.0077	0.0071	0.0063	0.0055	0.0052

FEI proposes to continue to report Leaks per KM of Distribution System Mains as an informational indicator.

Table A:C5-1-18 following summarizes FEI's existing and proposed service quality indicators along with the benchmarks and thresholds. Proposed changes to the SQIs are highlighted in Green in the table below.

Table A:C5-1-18: Summary of Proposed Service Quality Indicators

Indicators with Benchmarks and Thresholds			Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual results	Safety	**Emergency Response Time** - Calls responded to within one hour	>= 97.7%	96.2%	>=97.7%	96.2%
Annual results	Safety	**Telephone Service Factor (Emergency)** - Calls answered in 30 seconds or less	>= 95%	92.8%	>=95%	92.8%
3 Year rolling average	Safety	**All Injury Frequency Rate**	<= 2.08	2.95	<= 2.08	2.95
Annual results	Safety	**Public Contacts with Gas Lines**	<= 16	16	<=8	12
Annual results	Responsiveness to Customer Needs	**First Contact Resolution**	>= 78%	74%	>=78%	74%
Annual results	Responsiveness to Customer Needs	**Billing Index**	<= 5	<=5	<=3	5
Annual results	Responsiveness to Customer Needs	**Meter Reading Accuracy** - Number of scheduled meter reads that were read	>= 95%	92%	>=95%	92%
Annual results	Responsiveness to Customer Needs	**Telephone Service Factor (Non Emergency)** - Calls answered in 30 seconds or less	>= 70%	68%	>=70%	68%
Annual results	Responsiveness to Customer Needs	**Meter Exchange Appointment Activity**	>=95%	93.8%	>=95%	93.8%
Informational Indicators						
Annual results	Responsiveness to Customer Needs	**Customer Satisfaction Index**	n/a	n/a	n/a	n/a
Annual results	Responsiveness to Customer Needs	**Average Speed of Answer (replaces Telephone Abandonment Rate)**	n/a	n/a	n/a	n/a
Annual results	Reliability	**Transmission Reportable Incidents**	n/a	n/a	n/a	n/a
Annual results and 5 Year rolling average	Reliability	**Leaks per KM of Distribution System Mains**	n/a	n/a	n/a	n/a

4. DISCONTINUED SQIS

As discussed, FEI proposes to replace the existing Telephone Abandonment Rate with the Average Speed of Answer.

5. ANNUAL REVIEW PROCESS

FEI proposes to continue with the existing process for review of SQI performance at the Annual Review whereby FEI will review service quality for a year in the following year's Annual Review. This is consistent with the BCUC's direction.

In 2016, the BCUC issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The Commission determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The BCUC stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

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

Appendix C5-2

FBC SERVICE QUALITY INDICATORS

FBC SERVICE QUALITY INDICATORS

1. INTRODUCTION

Maintaining a high level of service quality is important to the long-term success of the Company. In support of this, and as in the 2014 to 2019 PBR Plan, FortisBC Inc. (FBC or the Company) proposes a suite of Service Quality Indicators (SQIs) be established as part of the proposed Multi Year Rate Plan (MRP). The SQIs will serve to ensure that service quality to our customers is maintained at acceptable levels throughout the term of PBR Period.

FBC proposes a suite of SQIs which builds on its experience. 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, THRESHOLDS AND HISTORY

2.1 *SERVICE QUALITY INDICATORS SELECTION CRITERIA*

In developing the proposed suite of SQIs for the current Application, the following criteria, similar to the criteria used for the current PBR Plan were considered:

Table A:C5-2-1: 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	Simple and transparent	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	Flexible	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 FBC continues to provide an "acceptable level" of service at an "acceptable level" of cost to our customers. Therefore, in setting SQI benchmarks, it is necessary to consider whether customers are willing to pay for additional improvements in the indicators, as incremental costs for achieving further improvements increase as the limit of the indicator is approached. Benchmarks typically reflect either industry standards or the Company's performance over recent prior periods.

2.3 *THRESHOLDS AND SATISFACTORY PERFORMANCE RANGES*

Thresholds or satisfactory performance ranges were introduced in the 2014 PBR Plan as an effective way to manage SQIs. In 2014, the BCUC in Order G-139-14 regarding FBC's 2014-2018 Multi Year PBR Application agreed that it was not appropriate to require FBC to be held to a specific performance benchmark. The BCUC stated:

> The Commission Panel agrees with Fortis and determines that it is not appropriate to require Fortis to be held to a specific performance benchmark for the following reasons. First, it does not take into account why SQIs are part of the PBR in the first place; that is to help mitigate the potential of serious degradation of service levels. Does being a percentage point below a prescribed performance benchmark result in a serious degradation of service? In most cases, a drop of this amount would have minimal impact yet could result in a penalty being imposed. Second, there is the issue of averages. If averages are relied upon to determine the performance benchmarks, it follows that results will fall below the benchmark approximately one half of the time. **Taking these points into consideration, the Commission Panel determines that the most effective way to manage SQIs is to set a satisfactory performance range.**

Through a consultative process with stakeholders, FBC and stakeholders reached an agreement titled the "Consensus Recommendation" on appropriate thresholds to consider. In the BCUC Order G-14-15 dated February 4, 2015, the Consensus Recommendation was approved.

2.4 *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 2007 PBR Plan 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. The 2014-2019 PBR Plan discontinued eight SQIs, replaced one, continued with eight existing SQIs, and added two new SQIs.

Table A:C5-2-2 following outlines the history and evolution of FBC's SQIs over the three PBR periods (1996-2004, 2007-2011, 2014 PBR and the proposed 2020 MRP).

Table A:C5-2-2: History and Evolution of SQIs at FBC (1996 - 2020)

	Service Quality Indicator	1996 PBR	2007 PBR	2014 PBR	2020 MRP
1	System Average Interruption Frequency Index	Included	Definition changed to Normalized	Included	Included
2	System Average Interruption Duration Index	Included	Definition changed to Normalized	Included	Included
3	Customer Average Interruption Duration Index	Included	Discontinued	Discontinued	Discontinued
4	Index of Reliability	Included	Discontinued	Discontinued	Discontinued
5	Generator Forced Outages	Added (1999-2004)	Included	Included	Included
6	Generation Incapability Factor	Added (1999-2004)	Discontinued	Discontinued	Discontinued
7	Generator Operating Factor	Added (1999 only)	-	-	-
8	System Losses	Included (1996-1998)	-	-	-
9	Customer Satisfaction Index	Included	Included (Redesigned)	Included	Included
10	Billing Accuracy	-	Included	Replaced with Billing Index	Included
11	First Contact Resolution	-	-	New customer service SQI	Included
12	Meters Read as Scheduled	-	Included	Included	Included
13	Telephone Service Factor	-	Included	Included	Included
14	Emergency Response Time	-	Included	Included	Included
15	Residential Connections Completion Time	-	Included	Discontinued	Discontinued
16	Residential Extensions Quoting Time	-	Included	Discontinued	Discontinued
17	Residential Extensions Completion Time	-	Included	Discontinued	Discontinued
18	Injury Frequency Rate	Included (Disabling Injury Frequency Rate)	Definition changed to All Injury Frequency Rate	Included	Included
19	Injury Severity Rate	Included	Included	Discontinued	Discontinued
20	Vehicle Incident Rate	Included	Included	Discontinued	Discontinued
21	Telephone Abandon rate	-	-	New customer service SQI	Replaced with Average Speed of Answer
22	Interconnection Utilization	-	-	-	New proposed

For the 2020 MRP, FBC reviewed the existing SQIs and believes that they remain appropriate to ensure that service quality to our customers is maintained at acceptable levels throughout the term of MRP. For some SQIs, FBC proposes to change their benchmarks, recognizing their recent historical performance. Additionally, FEI proposes to replace the existing Telephone Abandonment Rate with the Average Speed of Answer. FBC also proposes to report on a new informational SQI, called "Interconnection Utility", to measure the reliability of service for Wholesale Municipal customers. In the following sections, FBC provides discussion of the proposed SQIs, their benchmarks and thresholds.

3. PROPOSED SERVICE QUALITY INDICATORS, BENCHMARKS AND THRESHOLDS

3.1 *SAFETY SERVICE 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:

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

There are many variables affecting the response time including conditions such as time of day (during business hours or after business hours), number and type of events (i.e., widespread outages), available resources and location (travel times and traffic congestion) and weather conditions.

The current benchmark was set by the BCUC at 93 percent based on the average of FortisBC's annual results from 2010 to 2012. The following table summarizes the historical percentage of emergency events responded to within two hour results since the start of the current PBR Plan compared to the approved benchmark and threshold. Provided also are FBC's proposed benchmark and threshold for the 2020 MRP.

Table A:C5-2-3: Results during the PBR Plan for Emergency Response Time

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Emergency Response Time	91%	92%	97%	93%	94%	93%	93%	90.6%	90.6%

Table A:C5-2-4 below provides details of the 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 A:C5-2-4: Summary of FBC Emergency Activity Levels and Average Response Time

			Number of calls over two hours	Percent of responses in two hours or less
2014 to 2018	Number of calls	12,991	897	93%
	Average response time	1:16		
2018	Number of calls	2,539	170	93%
	Average response time	1:06		
2017	Number of calls	2,067	145	93%
	Average response time	1:08		
2016	Number of calls	2,356	71	97%
	Average response time	0:45		
2015	Number of calls	3,270	262	92%
	Average response time	1:34		
2014	Number of calls	2,759	249	91%
	Average response time	1:48		

On average during the five years, 2014 – 2018, of the current PBR Plan, the percentage of responses within two hours or less has been approximately 93 percent and consistent with the existing benchmark of 93 percent. While the results have been relatively consistent, variables such as the type of outage and the number of trouble calls to contribute to the observed volatility in the annual performance for this metric.

FBC proposes to continue to report on Emergency Response Time. Additionally, FBC believes the current benchmark represents the level of service expected by its customers and is appropriate and proposes to retain its existing benchmark and threshold for the term of the proposed MRP.

3.1.2 All Injury Frequency Rate

FBC is committed to continual improvement of corporate safety performance and will report employee safety performance as part of the Company's SQI profile using the metric All Injury Frequency Rate (AIFR). The reduction of work stoppage and efficiency losses as a result of safety incident reduction will promote productivity enhancements across the Company.

The AIFR is a comprehensive safety performance indicator based on lost time injuries (LTI) plus medical treatment injuries (MT) per 200,000 hours worked (approximately injuries per 100 workers). LTIs are injuries that result in one or more days missed from work. MTs are injuries where medical treatment was given or prescribed beyond medical aid and observation, and no lost time was involved.

The following formula is used:

$$\text{All Injury Frequency Rate} = \frac{\text{(Number of LTD + MT) x 200,000 hours}}{\text{Exposure Hours}^{1}}$$

For the purpose of this SQI, the measurement of performance is based on the three year rolling average of the annual results.

Following is a summary of FBC's AIFR annual and three year rolling average results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-2-5: Results during the PBR Plan for AIFR

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
AIFR – three year rolling average	2.58	2.52	1.97	1.27	1.28	1.64	1.64	2.39	2.39
AIFR – annual	3.21	1.54	1.15	1.13	1.52	n/a	n/a	n/a	n/a

The improving trend in the results support the conclusion that the high result in 2013 was anomalous in nature. The recent 2018 result was better than the approved benchmark which was set by the BCUC at 1.64 based on the average of FBC's annual results from 2010 to 2012.

Safety continues to be a core value for FBC and prevention of injury remains a key focus. FBC continues to focus on and reinforce the fundamentals of safety through effective safe work planning identifying hazards and mitigating risks, detailed work observations and thorough event analysis capturing learning and identifying opportunities for continued improvement. Target Zero is a program which was launched in January 2016. This program focuses on a number of key elements designed to enhance the existing safety management system and engage employees at all levels in safety as well as promote an interdependent safety environment. FBC believes this program has contributed to the positive safety trend experienced during the current PBR Plan.

[1] Exposure hours reflect actual hours worked excluding time off for vacation, statutory holidays, sickness, etc.

FBC remains committed to maintaining its focus on safety. FBC proposes to continue to report on AIFR and believes that the current benchmark and threshold remains appropriate for the term of the proposed MRP as the Company assesses the trend and sustainability of recent years' performance.

3.2 RESPONSIVENESS TO CUSTOMER NEEDS SQIs

3.2.1 First Contact Resolution (FCR)

First Contact Resolution (FCR) is an area of focus for FBC as research conducted suggests that it is the single most important driver of customer satisfaction. By maintaining a high level of FCR, the Company can effectively satisfy customers by resolving their issues effortlessly.

FCR measures the percentage of customers who receive resolution to their issue in one contact with FBC. FBC determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

Following is a summary of the FCR results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-2-6: Results during the PBR Plan for First Contact Resolution

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
First Contact Resolution	73%	76%	79%	80%	82%	78%	78%	72%	74%

The results from 2014 to 2018 have been better than the threshold with performance trending upwards over the years. The three recent years' performance (2017 and 2018) were better than the current benchmark of 78 percent approved by the BCUC, a target that was set above the industry average for call centre performance.

FBC proposes to continue to report on First Contact Resolution (FCR) and retain the existing benchmark with an increase to the threshold to 74 percent from 72 percent. Research confirms that a customer's ability to have their matter resolved at first instance is a leading indicator of customer satisfaction, and FBC continues to strive to improve this metric. In increasing the threshold, FBC is aligning it more closely to past performance.

3.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing processes by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the 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 objective is to achieve a score of five or less.

The relevant formulas and benchmarks for the three sub-measures are presented below.

Table A:C5-2-7: The Benchmarks and Formulas for Calculation of Billing Index SQI

Billing sub-measure	Percent achieved (PA)	Adjustment	Result
Percentage of bills accurate based upon input data	99.9%	* See formula below	5.0
Percentage of bills delivered to Canada Post within two days of date that the statement file is created	95%	(100% - PA)*100	5.0
Percentage of customers billed within two business days of the scheduled billing date	95%	(100% - PA)*100	5.0
Billing Service Quality Indicator (arithmetic average of sub-measures 1 to 3)			5.0

* IF [PA ≥ 99.9%, 5000 * (1 - PA), 100 * (1.05 - PA)]

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues.

Following is a summary of the Billing Index results since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-2-8: Results during the PBR Plan for Billing Index

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Billing Index	2.34	0.39	0.57	0.15	0.29	5.0	3.0	5.0	5.0

The results from 2014 to 2018 have been better than the benchmark approved by the BCUC. No significant billing issues have arisen over period.

FBC proposes to continue to report on the Billing Index as the Company believes that customers value complete, timely and accurate bills. Reflective of the recent historical performance and efficiencies achieved by the Company in producing bills, FBC proposes to lower the benchmark from 5.0 to 3.0 and to maintain the threshold at 5.0.

3.2.3 Meter Reading Accuracy – number of scheduled meters that were read

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

Factors influencing this SQI's performance typically include the resources available and system issues impacting the Company's billing or reading collections systems.

Table A:C5-2-9: Results during the PBR Plan for Meter Reading Accuracy

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Meter Reading Accuracy	98%	96%	99%	99%	99%	97%	98%	94%	95%

The results from 2014 to 2018 have been better than the benchmark approved by the BCUC. The current benchmark of 97 percent was based the annual results from 2010 to 2012.

FBC proposes to continue to report on the Meter Reading accuracy metric given the value customers place on receiving a timely and accurate bill. Reflective of recent historical performance, FBC proposes to increase the benchmark by one percent to 98 percent and to increase the threshold also by one percent to 95 percent.

3.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

The TSF is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

Following is a summary of the historical results for TSF (Non-Emergency) since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-2-10: Results during the PBR Plan for Telephone Service Factor (Non-Emergency)

Type of Call	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
Non Emergency	48%	71%	70%	70%	72%	70%	70%	68%	68%

The results from 2014 to 2018 were consistent with the benchmark of 70 percent except for 2014 which was negatively impacted by the events such as the first verified meter readings occurring after the IBEW labour disruption ended in December 2013, introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers.

FBC proposes to continue to report on TSF (Non-Emergency) and retain the existing benchmark and threshold for non-emergency calls.

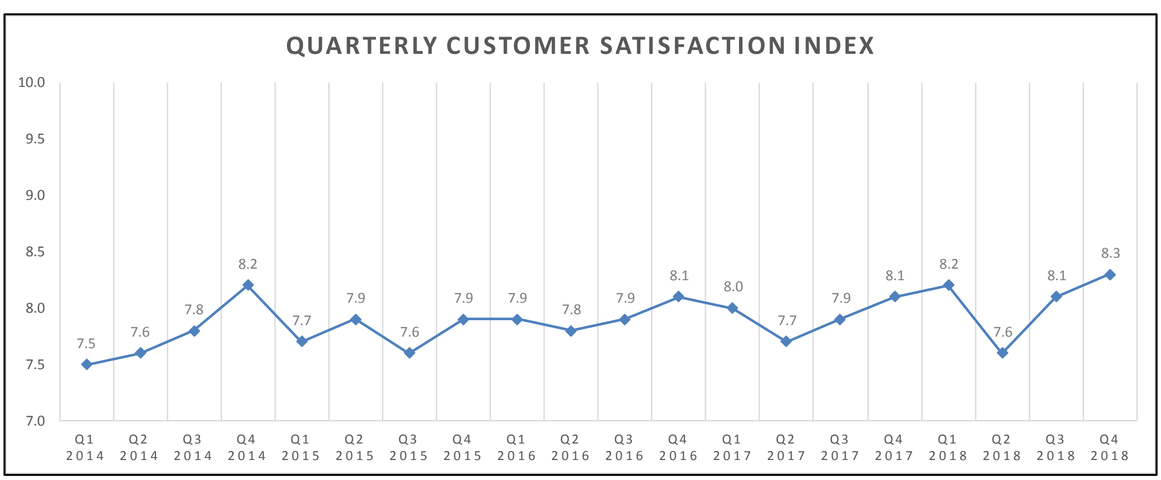
3.2.5 Customer Satisfaction Index (CSI)

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.

The graph below shows CSI results since 2014.

Figure A:C5-2-1: CSI Results



FBC proposes to continue using this metric an informational indicator. Customer attitudes are often influenced by factors outside the Company's control. Examples being 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.

FBC is planning to review the CSI index scoring and methodology. Customers' needs and wants change over time, as do their service expectations. The purpose of reviewing the index is to ensure we are measuring the factors that customers have identified as important to them in the current environment. FBC proposes continuing with the current CSI measure and calculations while this review occurs.

3.2.6 Telephone Abandonment Rate

The Telephone Abandon Rate is an informational indicator that measures the percent of calls abandoned by the customer before speaking to a customer service representative. Abandon rates can be due to waiting times, or due to customers receiving their required information through informational messages in the Company's Interactive Voice Response (IVR) system such that the customer no longer needs to speak to an agent.

Following is a summary of the historical results for Telephone Abandonment Rate since the start of the current PBR Plan.

Table A:C5-2-11: Results during the PBR for Telephone Abandonment Rate

Description	2014	2015	2016	2017	2018
Telephone Abandonment Rate	12.4%	2.7%	3.9%	4.7%	5.3%

The results from 2014 to 2018 have been stable and generally consistent from year to year except for 2014 which was negatively impacted by high call volumes resulting from the first verified meter readings occurring after the IBEW labour disruption ended in December of 2013, the introduction of the Residential Conservation Rate, and the integration of the City of Kelowna customers. FBC attributes the increase in the abandon rate in recent years to an increase in customers using the self-serving option through the interactive voice response messages during power outages. Customers who receive the required information through the automated messaging abandon the call without needing to speak with a FortisBC representative.

FBC proposes to replace the existing metric with another Informational Indicator, Average Speed of Answer (ASA).

FBC does not believe the Telephone Abandonment Rate is indicative of whether customer needs are being met. While assumptions can be made about why a call is being abandoned based on when it is abandoned, there is really no way to know why a customer abandoned a call, absent asking the customer directly. There may be positive reasons why a customer abandoned a call without talking to a customer service representative (e.g. they receive the information they were looking for from the recorded IVR message). The reasons may also be related to what is perceived to be a negative customer experience. Therefore, it is not possible to conclude with any certainty what the trends in the Telephone Abandonment Rate relate to.

The table below shows FBC's ASA (in seconds), for the last five years. These figures show, for example, that ASA for calls has continued to decrease since 2014 (with the exception of 2017). It should be noted that ASA in 2014 was impacted by the six months of job action that took place in Q3 and Q4 of 2013. Because meters were not getting read as regularly, more bills were estimated, causing significantly increased call volumes as bill adjustments were made.

Table A:C5-2-12: FBC Results during the PBR Plan for Average Speed of Answer (in seconds)

Description	2014	2015	2016	2017	2018
Average Speed of Answer	225.78	49.07	48.48	48.71	48.64

3.3 *RELIABILITY SQIs*

FBC measures transmission and distribution system reliability according to 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-hours. Threshold values are calculated by applying a statistical method called the "2.5 Beta" adjustment to historical reliability data. Any single outage event that exceeds the threshold value is excluded from the reliability data. Excluding major events allows them to be studied separately and reveals trends in daily operations that would be hidden or skewed if they were included in the data set. Major event days in the FBC service territory have been caused by mudslides, wind or snow storms and wildfires.

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

3.3.1 System Average Interruption Index (SAIDI) – Normalized

SAIDI is the amount of time the average customer's power is off during the year (i.e., the total amount of time the average customer's clock would lose during a year), after adjusting for the impact of major events as described above, and is calculated as follows:

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

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.

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

Following is a summary of the historical results for SAIDI since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan.

Table A:C5-2-13: Results during the PBR Plan for SAIDI

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
SAIDI	2.09	2.15	2.18	2.76	3.10	2.22	TBD	2.62	TBD

From 2014 to 2016, the results have been stable and generally consistent from year to year. Starting in 2017 and in 2018, the results have been influenced by the implementation of the Outage Management System (OMS), a system used to record distribution outages based on the outage start time. The OMS replaced a manual system and has automated the tracking and reporting of outage data through integration with the FBC AMI system. With the previous system, the outage start time was recorded as the time that the outage was confirmed in the field. With the OMS, the outage start time is based on the earliest of the AMI or customer call-in for the outage. With the change in the OMS and a different definition to the outage start time, the reported outage times have increased, causing SAIDI values reported to increase, even though there has been no change in the Company's operating practices. FBC estimates the increase in the reported values for SAIDI as the result of the OMS to be in the 15 to 30 percent range, consistent with other utilities' experience who have replaced their manual systems with an OMS. Additionally, the 2017 SAIDI results were impacted by wildfires, specifically in the Princeton and Joe Rich areas of the Okanagan, accounting for approximately 78,000 customer hours or 15 percent of the annual SAIDI. The 2018 SAIDI results were also impacted by adverse weather (i.e., large snow fall events) related outages.

FBC proposes to continue to report SAIDI. To adjust for the influence of the OMS on the higher SAIDI results reported, FBC proposes to update the existing SAIDI three year rolling average benchmark. For the next MRP, starting 2020, FBC will have three full years of SAIDI results available (i.e., 2017, 2018, 2019) incorporating the impact of the OMS. As the 2019 SAIDI results will not be available until early 2020, FBC will be providing the proposed benchmark based on a three year rolling average and the threshold for the next MRP in early 2020.

In addition, FBC proposes to revise the basis for the actual results reported from the current three-year rolling average approach to a current year only approach. A current year results focus approach is a clearer indicator of the Company's performance in a given year than one based on a three year rolling average. Additionally, a current year results focus is generally easier to understand.

In conjunction with this change, FBC proposes to change the threshold to reflect the annual results, consistent with the basis for the actual results. Similar to the approach used to determine the existing threshold, the proposed threshold will be based on statistical analysis (i.e., standard deviation) of the SAIDI historical results

3.3.2 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), after adjusting for the impact of major events as described above, and is calculated as follows:

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

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

For the purposes of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

Following is a summary of the historical results for SAIFI since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan.

Table A:C5-2-14: Results during the PBR Plan for SAIFI

Description	2014	2015	2016	2017	2018	Benchmark		Threshold	
						Current	Proposed	Current	Proposed
SAIFI	1.39	1.49	1.51	1.56	1.62	1.64	TBD	2.50	TBD

From 2014 to 2018, the results have been better than the benchmark. Similar to SAIDI, the SAIFI results in 2017 and 2018 have been influenced by the implementation of the OMS, although to a lesser degree. The OMS has eliminated even the small number of outages that may previously have been inadvertently omitted from the manually-maintained outage statistics.

To adjust for the influence of the OMS on the higher SAIFI results reported, FBC proposes to update the existing SAIFI three year rolling average benchmark. For the next MRP, starting 2020, FBC will have three full years of SAIFI results available (i.e., 2017, 2018, 2019) incorporating the impact of the OMS. As the 2019 SAIFI results will not be available until early 2020, FBC will be providing the proposed benchmark based on a three year rolling average and the threshold for the next MRP in early 2020.

In addition, FBC proposes to revise the basis for the actual results reported from the current three-year rolling average approach to a current year only approach. A current year results focus approach is a clearer indicator of the Company’s performance in a given year than one based on a three year rolling average. Additionally, a current year results focus is generally easier to understand.

In conjunction with this change, FBC proposes to change the threshold to reflect the annual results, consistent with the basis for the actual results. Similar to the approach used to determine the existing threshold, the proposed threshold will be based on statistical analysis (i.e., standard deviation) of the SAIFI historical results

3.3.3 Municipal Wholesale Customers Service Quality – Interconnection Utilization

In response to concerns brought forward by the BCMEU that the SQIs were not prepared in contemplation of the specific concerns of wholesale customers, FBC proposes to establish a new informational service quality indicator to monitor the level of service provided to the municipal wholesale customers (i.e., City of Penticton, City of Summerland, City of Grand Forks and City of Nelson).

The new metric, "Interconnection Utilization", is a measurement of the time that an interconnection point was available and providing electrical service to these customers. There are twelve points of interconnection combined between the four customers as shown in the table below:

Table A:C5-2-15: Interconnection Points

Customer	Point of Interconnection
City of Nelson	Rosemont Substation
	Coffee Creek Substation
City of Penticton	Huth Avenue Substation (13kV)
	Huth Avenue Substation (8kV)
	Waterford Substation
	Westminister Substation
	R.G. Anderson Substation
City of Summerland	Summerland Substation
	Trout Creek Substation
City of Grand Forks	Ruckles Substation (DB1)
	Ruckles Substation (DB2)
	Donaldson Drive

The Interconnection Utilization metric for the interconnection points listed is calculated as follows:

$$\frac{\text{Total Operating Hours}}{\text{Total Operating Hours + Total Outage Time}}$$

Following is a summary of the historical results for Interconnection Utilization since the start of the current PBR Plan.

Table A:C5-2-16: Results during the PBR Plan for Interconnection Utilization

Description	2014	2015	2016	2017	2018
Interconnection Utilization	99.99%	99.94%	99.99%	99.95%	99.96%

As an example of the calculation shown above for 2018, these interconnection points were providing service for 105,082 hours out of the available 105,120 hours, at a Interconnection Utilization performance level of 99.96 percent. From 2014 to 2018, the results have been stable from year to year.

3.3.4 Generator Forced Outage Rate

Generator Forced Outage Rate (GFOR), an informational indicator, is a measure of the percentage of time in one year that the generating units experienced forced outages compared to the amount of time they could have operated without a forced outage. A forced outage means the removal of a generating unit from service due to the occurrence of a component failure or other event, making it unavailable to produce power due to the unexpected breakdown. The GFOR is defined by CEA as follows:

$$\frac{\text{Total Forced Outage Time}}{\text{Total Forced Outage Time + Total Operating Time}} \text{ X 100}$$

Following is a summary of the historical results for GFOR since the start of the current PBR Plan, the approved benchmark and threshold for the current PBR Plan, and the proposed benchmark and threshold for the 2020 MRP.

Table A:C5-2-17: Results during the PBR Plan for GFOR

Description	2014	2015	2016	2017	2018
GFOR	1.7%	0.1%	0.9%	0.6%	0.4%
CEA Industry Average	6.3%	6.2%	6.2%	6.2%	

From 2014 to 2017, the results have been stable from year to year and much lower than the CEA industry average of approximately 6.2 percent during the same period. The 2014 results were higher than the other years due to forced outages arising from fires at the Corra Linn and South Slocan generating plants.

FBC proposes to continue to report GFOR as an informational indicator.

4. SUMMARY OF PROPOSED SERVICE QUALITY INDICATORS

Table A:C5-2-18 following summarizes FBC's proposed service quality indicators along with the proposed benchmarks and thresholds. Proposed changes to the SQIs are highlighted in Green in the table below.

Table A:C5-2-18: Summary of Proposed Service Quality Indicators

Indicators with Benchmarks and Thresholds			Current Benchmark	Current Threshold	*Proposed* Benchmark	*Proposed* Threshold
Annual	Safety	**Emergency Response Time** - Calls responded to within two hours	>= 93%	90.6%	>=93%	90.6%
3 Year	Safety	**All Injury Frequency Rate**	<=1.64	2.39	<=1.64	2.39
Annual	Responsiveness to Customer Needs	**First Contact Resolution**	>= 78%	72%	>=78%	74%
Annual	Responsiveness to Customer Needs	**Billing Index**	<= 5	<=5	<=3	5
Annual	Responsiveness to Customer Needs	**Meter Reading Accuracy** - Number of scheduled meter reads that were read	>= 97%	94%	>=98%	95%
Annual	Responsiveness to Customer Needs	**Telephone Service Factor** - Calls answered in 30 seconds or less	>= 70%	68%	>=70%	68%
Annual	Reliability	**System Average Interruption Duration Index - Normalized**	<= 2.22	2.62	TBD	TBD
Annual	Reliability	**System Average Interruption Frequency Index - Normalized**	<= 1.64	2.50	TBD	TBD
Informational Indicators						
Annual results	Responsiveness to Customer Needs	**Customer Satisfaction Index**	n/a	n/a	n/a	n/a
Annual results	Responsiveness to Customer Needs	**Average Speed of Answer (replaces Telephone Abandonment Rate)**	n/a	n/a	n/a	n/a
Annual results	Reliability	**Generator Forced Outage Rate**	n/a	n/a	n/a	n/a
Annual results	Reliability	**Interconnection Utilization**	n/a	n/a	n/a	n/a

5. DISCONTINUED SQIs

As discussed, FBC proposes to replace the existing Telephone Abandonment Rate with the Average Speed of Answer.

6. ANNUAL REVIEW PROCESS

FBC proposes to continue with the existing process for review of SQI performance at the Annual Review whereby FBC will review service quality for a year in the following year's Annual Review. This is consistent with the BCUC's direction.

In 2016, the BCUC issued its Reasons for Decision accompanying Order G-44-16 in FBC's All Injury Frequency Rate Compliance Filing. The BCUC determined that it was appropriate to review FBC's service quality for a year in the following year's annual review. The BCUC stated:

> The Panel finds that the most appropriate timing for determining if a serious degradation of service has occurred and if a financial penalty is warranted is during the following year's annual filing. FortisBC Inc. is directed to address its 2015 service quality and/or penalties in its next Annual Review filing, anticipated in the summer or fall of 2016. Going forward, it is anticipated that this same timing will be used to make final determinations on questions of serious degradation of service and financial penalties for subsequent years covered by the Performance Based Ratemaking regime. The Panel agrees with FBC that this lag provides for a more complete evidentiary record on which to make the necessary determinations. Further, as compared to a transition to mid-year SQIs, this approach provides a more elegant and effective solution to the problem contemplated in the Reasons to Order G-202-15.

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

Appendix C6

INNOVATION REPORTS

Appendix C6-1

REGULATOR RATIONALE FOR RATEPAER-FUNDED ELECTRICITY AND NATURAL GAS INNOVATION, CONCENTRIC

REGULATOR RATIONALE FOR RATEPAYER-FUNDED ELECTRICITY AND NATURAL GAS INNOVATION

PREPARED FOR:

CANADIAN GAS ASSOCIATION and CANADIAN ELECTRICITY ASSOCIATION

April 2018

CONCENTRIC ENERGY ADVISORS

WWW.CEADVISORS.COM

Table of Contents

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EXECUTIVE SUMMARY

The case for utility-led, ratepayer-funded innovation has strengthened over the past decade and is being driven by a series of interconnected energy realities. These include the need to employ technology to integrate significant quantities of customer-sited distributed energy resources, the emergence of new natural gas end-use technologies, and a recognition by governments that utilities can play a central role in the achievement of energy and environmental public policy goals that require innovative solutions. Regulators in Canada should take note that these factors have taken hold among global economic regulators and this report concludes that the trend is spreading beyond some of the early movers: The United Kingdom, California, New York and British Columbia. The responsibility for ensuring that innovation prepares the energy industry to realize the potential for reliable, affordable, and clean energy with greater customer choices among products and services is shared by the utilities, regulators and other policy makers.

It is becoming increasingly accepted that new business models need to be developed, enabled by energy and data system technologies that require development and testing before they can be deployed at scale. Network infrastructure (pipeline and wire) modernization is an explicit goal for utilities and regulators, for both gas and electric utilities. Future investments in the networks are being designed to support an unfolding market characterized by engagement of both customers and third parties in the utility business model and the implementation of new consumer products and services. Utilities can support this evolving market via rate-funded demonstration projects that test new technologies and business models. Generally, while innovation in energy technologies and less expensive ways of performing traditional utility activities continue to grow, there has been more focus in the past few years on integration of demand energy resources, new business models, and the security of "big data" that enables this transformation. These programs de-risk investments for both customers and shareholders and help establish the business case for full-scale technology development and market adoption. Utility-led technology deployment and demonstration activities will have important direct benefits for customers by improving the way their customers use energy, control their energy use and derive benefit from it. Further, we are seeing many national and subnational governments developing large technology and funding programs. Utility ratepayer funding offers an opportunity to leverage these funds.

Regulators have another important objective with innovation: to spur a transformation of utility cultures to become learning and innovative organizations. Electricity and natural gas "utilities of the future" will be required to leverage advancements in energy technology, big data, and the desire of consumers to be evermore involved in their energy use patterns. Regulators also cite a desire to increase the reliability and resiliency of utility service and improve environmental performance.

The United Kingdom regulator concluded that its earliest efforts at innovation, the Low Carbon Network Fund (LCNF), which aimed to achieve aggressively low carbon goals, demonstrated that regulation has a critical role in promoting utility innovation and removing existing barriers for utilities. California has long been a supporter of customer-funded demonstration projects and continues this effort. New York's policy makers have implemented longer-term research and development programs, and requested that the regulator adopt a longer-term perspective when evaluating ten-year business plans that can be reprioritized during the plan as experience is gained. Minnesota has engaged a stakeholder process to contribute to the design of demonstration projects before they are submitted for review by the regulatory commission, thereby improving the opportunities for learning by all parties. AVANGRID, for example, is developing a demonstration "Energy Smart Community" that will test new customer engagement and business models after it installs Advanced Metering capabilities for over 10,000 customers in Ithaca, New York. Australia has supported customer-funded innovation that aims to reduce peak demand as growth is threatening reliability and will require expensive infrastructure investments. Ontario currently funds innovation through a combination of customer, utility shareholder, and vendor funding. The Ministry of Energy recently published a 2017 Long Term Energy Plan that focuses more intently on the role of innovation, and the potential barriers presented by existing regulation. The Massachusetts Commission has recently signaled its willingness to fund demonstration projects, indicating a willingness to follow through with a policy that was established in 2014 by a prior Commission. In British Columbia, an ambitious provincial clean energy policy has provided flexibility for utilities to propose - and the regulator to approve - customer-funded innovation projects in areas such as renewable natural gas and natural gas for transportation. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

Table ES-1 identifies programs in each of these jurisdictions where regulators have made an explicit determination that they meet specific innovation or demonstration project requirements to merit customer funding.

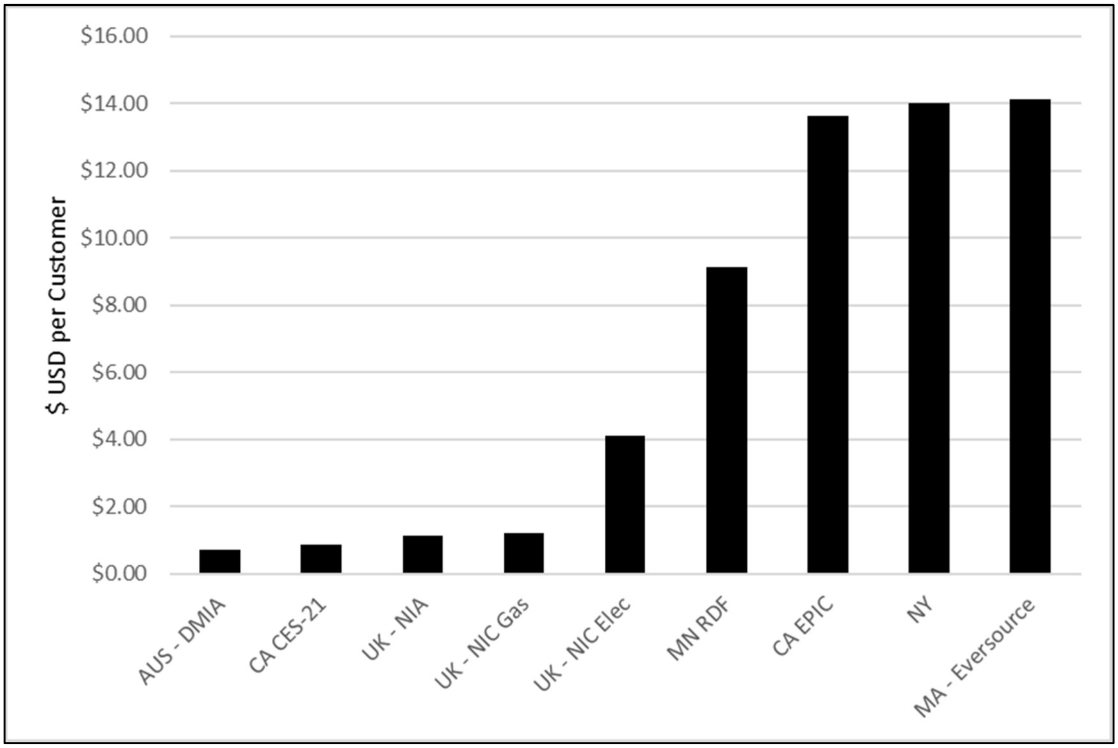
Table ES-1: Summary of Innovation Programs

Regulator/ Government	Program/ Directive	Link to Program	Start Date	Funding Level (annually per customer, $USD)
Ofgem	RIIO framework: Network Innovation Allowance (NIA) & Network Innovation Competition (NIC)	https://www.ofgem.gov.uk/network-regulation-riio-model https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation	2013-2015*	NIA: $1.13 NIC: $4.11 Electricity, $1.23 Gas
California PUC	California Energy Systems for the 21st Century (CES-21)	https://www.llnl.gov/sites/default/files/field/file/CES21.pdf	December 2012	$0.87
California PUC	Electric Program Investment Charge (EPIC)	http://www.energy.ca.gov/research/epic/	May 2012	$13.61
New York PSC and NYSERDA	Reforming the Energy Vision (REV)	https://rev.ny.gov/ http://www.dps.ny.gov/REV/	April 2014	NYSERDA funding: $4.69 ConEd REV project: $9.33
Minnesota PUC	Renewable Development Fund	https://www.xcelenergy.com/energy_portfolio/renewable_energy/renewable_development_fund	1994	$9.12
Australian Energy Regulator	Demand management incentive scheme and innovation allowance mechanism	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism	December 2017	DMIA: $0.72 *(hypothetical)*
Massachusetts DPU	Order requiring Grid Modernization Plan	http://www.raabassociates.org/Articles/MA%20DPU%2012-76-B.pdf	June 2014	Eversource demo projects: $14.12
IESO (Ontario)	Conservation Fund	http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview	2005	*Insufficient data*

*Start dates vary by gas vs. electricity, and transmission vs. distribution.

Funding levels for innovation vary across the jurisdictions we have examined. The most recent data are summarized below in Table ES-2. These programs span a range from $0.72 to $14.12 per customer, or an average of $6.55. While virtually all policymakers and regulators express concern for costs, they also recognize the potential benefits. Ratepayer advocates have expressed concern that demonstration projects should be sufficiently defined with quantifiable benefits to support such investments.[1] The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples.[2]

Diagram ES-2: Examples of Utility Funding Levels, in Annual USD Per Customer[3]



Notes:
AUS – DMIA: Australia Demand Management Innovation Allowance
CA CES-21: California Energy Systems for the 21st Century
UK – NIA: Ofgem Network Innovation Allowance
UK – NIC Gas/Electric: Ofgem Gas/Electric Network Innovation Competition
MN RDF: Minnesota Renewable Development Fund
CA EPIC: California Electric Program Investment Charge
NY: New York State Energy Research & Development Authority and Con Edison
MA – Eversource: Eversource Grid Modernization Plan projects

In considering these funding levels, policymakers and regulators might ask: what is the optimal level of funding, which programs are most successful, and what factors determine whether funding should be increased or decreased? These are important questions without easy answers, but our research sheds light on them. Where energy policy dictates a shift in the status quo, funding levels would be expected to be higher to facilitate the transition, and targets comparable to the CA-NY-MA range may be appropriate. Given the relatively new nature of utility funded innovation, it is difficult to measure success, but Ofgem programs appear at the forefront, with benefits for certain programs estimated in the 4.5-6.5 times funding level range. Capital investment theory stipulates that any investment with a positive return should be undertaken with risk and capital costs factored in. This suggests that program funding up to a return ratio of 1:1 is warranted. Even with current budgets, California has estimated its RD&D funding gap is as much as $670 million per year. As long as estimated benefits continue to exceed funding levels, policymakers and regulators are serving the public interest.

Overall, this report documents the trend toward increased customer funding of innovation projects in both the natural gas and electricity industries and cites the rationale relied upon by policy makers and regulators. In some jurisdictions, the changes are implemented through a combination of legislation and regulation. The potential returns from innovation are significant. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits clearly justify the costs of demonstration projects.

INTRODUCTION

Concentric's 2014 report, "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" described the significant benefits that energy innovation provides to customers and society with benefit-to-cost ratios in the 2 to 5:1 range across several programs. As noted in the Executive Summary:

> *An increased emphasis on innovation by utilities could yield a range of new technologies, applications, processes, and business models—e.g., more efficient end-use equipment, smart-grid technologies and services, advanced low-carbon energy sources, energy storage technology solutions, and community energy systems. Such innovations can provide cleaner, less expensive energy services to Canadian households and businesses while creating jobs, bolstering Canadian competitiveness, and promoting Canada's position among global energy leaders.*[4]

The 2014 report provided a framework for evaluation of alternative funding mechanisms, focusing primarily on government (taxpayer) and utility (customer) funding options. Government funding is most appropriate in the high-risk early research & development phase or where there are significant spillover benefits that discourage risk-taking. Utility customer funding is most appropriate where the benefits largely accrue to utility customers and where they are in a unique position to test new technologies and business models. The report identified potential obstacles to utility innovation and recommended a utility customer-funding model that maintains active regulatory oversight.

Two subsequent updates (2015 and 2016) provided updates on trends in utility-sponsored innovation along with examples of recent projects. This 2018 update focuses on customer-funded innovation programs with a deeper dive into the reasons why regulators in eight jurisdictions support customer-funded innovation. These include four leading United States jurisdictions (California, New York, Minnesota, and Massachusetts), two Canadian provinces (Ontario and British Columbia), and two international jurisdictions (Great Britain and Australia). We supplemented regulatory research with regulatory and policy interviews in these jurisdictions to obtain perspective on whether the programs were working, and indications of results achieved to date. The following sections describe the approaches taken in each jurisdiction and insights gained from evaluation of these programs.

CUSTOMER-FUNDED INNOVATION FROM AROUND THE GLOBE

1. UNITED KINGDOM

'The United Kingdom's energy regulator, the Office of Gas and Electricity Markets ("Ofgem"), has been an international leader in regulatory reform since its predecessor agencies were established when natural gas and electricity markets were privatized in the 1980s. Notably, it was an earlier adopter of performance-based regulation ("PBR"). The most recent version of this multi-year utility revenue model is "RIIO", representing the equation, "Revenue = Incentives + Innovation + Outputs", which was applied to natural gas and electricity distributors in 2013 and 2015, respectively. This new model was the result of a "RPI-X@20" review of PBR as applied in the UK. During this same era, Ofgem and the U.K. utilities gained experience with the Low Carbon Network Fund (LCNF).

The LCNF provided approximately £250m of funding for Distribution Network Operators ("DNOs") during the 2010-2015 period, a dramatic increase in innovation funding that was occurring under the PBR framework. LCNF was part of the electricity distribution price control. In the electricity distribution network, there are 14 DNOs which are owned by 6 groups. Focusing on achieving a low-carbon future while maintaining reliability and efficient services to customers, the LCNF was designed to integrate innovation as part of normal business operations and to share learning across the six DNOs. The estimated net benefit from this investment was £1.1 to £1.7 billion[5] or 4.5 to 6.5 times the funding level.[6]

The concept of compensating utilities for how well they perform as innovators grew from the recognition that the energy sector was about to experience significant change and that utilities needed to be able to innovate in order to respond to evolving customer demands and policy drivers.[7] Ofgem recognized that even within the new incentive-based ratemaking framework, "research, development, trials and demonstration projects - the earlier stages of the innovation cycle - are speculative in nature and yield uncertain commercial returns."[8] Ofgem recognized that even "failures" in terms of innovation attempts could provide useful information.[9]

Regulatory Rationale

Ofgem noted that the innovation stimulus is intended to "kick start" a cultural change at utilities.[10] Innovation funding is provided by customers since they will benefit from innovations.[11]

The initial decision noted that there was widespread support throughout the consultation for an incentive for innovation:

> *Given the scale of the challenge that network companies face and the uncertainty about how best to deliver, innovation is needed to ensure network companies deliver a sustainable energy sector and long-term*

> *value for money. The need for innovation has been widely recognized throughout RPI-X@20, including in responses to our consultations.*[12]

Ofgem concluded that networks will need to become a lot "smarter" to meet several challenges including:

- connecting more home-based microgeneration, i.e., solar panels and small scale renewable generation;
- connecting more small-scale renewables and CHP to the low voltage distribution network;
- balancing the electricity network to manage large amounts of renewable generation which by its nature is intermittent; and
- gas networks will face further growth in the use of Liquefied Natural Gas, as well as carbon capture and storage facilities at power stations.[13]

This rationale was restated in a March 2017 network innovation review:

> *As a consequence, network-related costs could increase significantly from connecting large volumes of generation, as well as managing the impacts of new sources of gas. We think it is in consumers' interests that the network companies respond creatively to the challenges posed by these changes. New approaches could deliver more efficient and timely services needed by network customers and lessen the cost impact on consumers. This might be achieved, for example, by developing and adopting new technology, different operational practices and novel commercial arrangements.*[14]

Ofgem noted the enormity of the investment that will be required to achieve its objectives, estimating that approximately £32 billion (approximately $53 billion Canadian dollars) of network investment will be required.[15] Ofgem recognized that in order to have an impact, the incentives for innovation must be significant:

> *The innovation stimulus package will include substantial prize funds to reward network companies and third parties that successfully implement new commercial and charging arrangements to help deliver a sustainable energy sector.*[16]

Ofgem established two distinct innovation funding programs to implement the innovation component of RIIO: the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). These two programs fund research by the Distribution Network Operators (DNOs) that will facilitate the transition to a low carbon economy, while providing cost savings to customers. Customers will pay for these activities through their energy bills. The NIA is for funding smaller innovation projects and is a set annual allowance available to each network operator. For electricity distribution, Ofgem required utilities to define innovation strategies based on NIA funding of between 0.5 and 1 percent of their base revenues. NIA projects do not require individual project approvals. While funding caps are company-specific, they have generally been between 0.5 and 0.7% for both electric and natural gas DNOs. £61 million is available for the NIA annually.[17]

The NIC is an annual competition to fund selected innovation projects, and is focused on larger, more complex projects that require approval.[18] In 2016, Ofgem provided £44.6 million in funding to six projects through the NIC. This funding is combined with the companies' contributions and external funding, creating a total of £53.9 million (approximately $75 and $90 billion Canadian dollars, respectively). These recently approved projects are shown in Table 1. The projects must meet certain criteria, such as generating new and shareable knowledge, being cost effective, and accelerating to move to a low carbon energy sector.[19] The total annual funding available for the electricity NIC was recently reduced to £70 million, down from £90 million, but the amount available annually for gas networks remained at £20 million.[20]

Table 1: NIC Projects Approved in 2016

	Project	DNO	Funding Sources	Length	Description
ELECTRIC	OpenLV	Western Power Distribution	4.9m – NIC, 0.5m – WPD, 0.5m – partners	3 years	Develop software platform to enhance visibility of residential substations
ELECTRIC	TDI 2.0	National Grid Electric Transmission	8m – NIC, 1.5m – NGET + UKPN	3 years	Test technical & commercial solutions to resolve constraints on the transmission network
ELECTRIC	PowerFul-CB	UK Power Networks	4.6m – NIC, 0.6m – UKPN, 0.9 – partners	4.5 years	Develop 2 types of circuit breakers on GB network
ELECTRIC	Phoenix	SP Transmission	15.6m – NIC, 1.8m – SPT, 2.3m – partners	4 years	Test new way of providing services (traditionally fossil-fueled power stations) to balance electricity network
GAS	HyDeploy	National Grid Gas Distribution	6.8m – NIC, 0.4m – NGGD, 0.4m – NGN	3 years	1st practical deployment of hydrogen onto live GB gas distribution network since the 1970s
GAS	Future Billing Methodology	National Grid Gas Distribution	4.8m – NIC, 0.5m – NGGD	3 years	Explore options for fair & equitable billing methodology, fit-for-purpose in lower carbon future

DNOs submit annual reports that provide a summary of all NIA projects. Customer-facing NIA projects are the subject of more detailed technical reports. DNOs have been providing individual reports on each NIC project that present spending updates along with learning to date and key challenges and risks that have been encountered. This is being transitioned to a single report for each company in 2018.

NIC projects were eligible for rewards based on successful delivery, but this has been subsequently eliminated now that the programs are up and running and the DNOs have been deemed to be managing the programs well.

Interview Insights[21]

The UK's focus on innovation is intended to produce a low-carbon future, while also driving down costs for network customers. Ofgem has significant authority and has not required legislation to implement its innovation agenda. The LCNF experience, supported by a survey from an independent evaluation report prepared by the consultancy Pöyry in October 2016, demonstrated that regulation has a critical role to serve in promoting utility innovation and removing existing barriers for DNOs.[22] The NIA and NIC programs continued the goal to foster a more innovative culture within network companies. Policy makers are hopeful that the innovative culture will be applied to resolving industry challenges as they arise and provide value to customers. Ofgem has made tweaks to governance over the past few years, providing more flexibility to DNOs based on satisfactory performance to date.

Funding Levels

In 2016, funding for the NIC was approximately £3.05 per electric customer and £0.91 per gas customer ($4.11 and $1.23 USD, respectively). With the reduction of £90 million to £70 million in electric NIC funding, future funding will be approximately £2.37 per electric customer ($3.20 USD).[23]

Insights: The UK government, through Ofgem, has made utility innovation a key objective of its regulatory framework. The regulator wants to drive cultural change at utilities in order to create a smarter, distributed, renewable, sustainable, efficient, and diversified electric and gas grid for the benefit of customers. Utility customer funding is utilized along with co-funding from third party vendors. The goals and scope of the UK program are among the most ambitious examined.

2. CALIFORNIA

California has two large programs that fund RD&D in the energy sector. The CES-21 program is a collaborative effort among the three large investor-owned utilities and Lawrence Livermore National Laboratories (LLNL) that funds investments in several specified areas, focusing most recently on cybersecurity and grid integration projects. The Electric Program Investment Charge (EPIC) Program funds investments that promote the adoption of clean technologies. Both programs are reviewed and approved by the California Public Utilities Commission (CPUC) and rely on customer funding.

In 2011, California's three large investor-owned utilities requested approval from the CPUC to enter into a five-year, $150 million research and development agreement with LLNL that was projected to produce over $550 million in savings. This program is referred to as the "21st Century Energy Systems Research Project" or "CES-21". The PUC approved this initial funding level in 2012 after determining that the proposal was consistent with a provision in the California Public Utility statute that authorized the CPUC to approve utility research, development and demonstration (RD&D) programs that considered the following guidelines:

1. Projects should offer a reasonable probability of providing benefits to ratepayers.
2. Expenditures on projects which have a low probability of success should be minimized.
3. Projects should be consistent with the corporation's resource plan.
4. Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.
5. Each project should also support one or more of the following objectives:
    a. Environmental improvement;
    b. Public and employee safety;
    c. Conservation by efficient resource use or by reducing or shifting system load;
    d. Development of new resources and processes, particularly renewable resources and processes which further supply technologies;
    e. Improve operating efficiency and reliability or otherwise reduce operating costs.

Regulatory Rationale

The statute provides the CPUC with the clear authority to approve RD&D funding by utilities and establishes a set of guidelines to consider. In the absence of clearly expressed legislative intent, the CPUC could have relied on more general "public interest" statutory provisions that are common in utility statutes. The Commission cited a Staff position suggesting that the California RD&D funding gap was as much as $670 million per year.[24]

Noting that the petition was consistent with the statutory guidance, the CPUC cited six benefits to utility customers:

1. The research findings are very likely to improve the safety of gas operations by reducing the gas pressure in transmission pipes needed to maintain distribution flows, by improving leak detection, and by predicting pipe breaks;
2. The project is very likely to provide benefits to ratepayers that exceed costs across both electric and gas operations by avoiding unnecessary purchases of power support services and by identifying with precision places where more grid investment is needed;
3. Research pertaining to the operations of electric and gas utilities is currently underfunded;
4. The research pertaining to cybersecurity will better protect both electric and gas operations and customer privacy;
5. Only the use of supercomputers, a core strength of LLNL, will enable utilities to process the three terabytes of data a day produced by smart meters and thereby improve grid operations and stability; and
6. The proposed research uses the special research strengths of LLNL in supercomputing, modeling, and cybersecurity.

It is evident from the fifth and sixth reasons that the CPUC was particularly focused on cybersecurity and potential threats to customer privacy and network security. In approving the initial funding levels of $30 million per year, the CPUC exercised care not to be overly prescriptive and require detailed project definitions, recognizing that the projects would be developed over time through collaboration among the utilities and LLNL. These decisions were delegated to CES-21's Board of Directors subject to the requirement that projects must fall within one of four areas: Gas Operations, Electric Operations, Electric Resource Planning, and Cybersecurity. The CPUC approved the agreement over the objections of two California ratepayer advocate organizations (TURN and DRA) whose objections focused on governance concerns, citing the reliance on estimates of benefits and the delegation of decision-making authority to CES-21's Board of Directors.

Subsequent legislation enacted in 2014 (Senate Bill 96) reduced the level of spending from approximately $150 million to $35 million over the five-year period. The Bill limited the areas of research to cyber security and grid integration and streamlined the governance process while adding more rigorous monitoring and reporting requirements that documented expenditures and described the beneficial outcomes from the research, as well as limiting administrative charges to 10% of program budgets. The limit was in response to concerns regarding administrative costs that were charged to the program and recovered from customers. The CPUC decision reaffirmed its support for RD&D by utilities.[25]

The program has been operating for a few years, and annual reports which detail progress to date have been released. Most recently, the 2016 Annual Report discussed updates to the cybersecurity and grid integration projects. The Simulation Engine has modeled security threats and malware attacks, and outreach sessions have focused on identifying synergies and checking for duplication. The project has also expanded simulations of the Western Interconnect, modeling every generation unit and load zone across the region. This allows the researchers to examine power flows between regions to study the impact on the grid's need for operational flexibility.[26] The cybersecurity project will continue addressing next steps over the coming years, while the grid integration half of the program is set to produce the final deliverables by 2018.

The EPIC program was established by the CPUC in 2012, and consists of the three utilities administering an RD&D program that funds innovative technologies and approaches that promote reliability, lower costs, and increase safety. The investment decisions reflect the following principles:

1. Providing societal benefits;
2. Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost;
3. Supporting California's loading order to meet energy needs first with energy efficiency and demand response, second with renewable energy (distributed generation and utility scale), and third with clean conventional electricity supply;
4. Supporting low-emission vehicles and transportation;
5. Providing economic development; and
6. Using ratepayer funds efficiently.

A broad range of programs has been implemented including research on net zero emissions buildings, testing of new demand response strategies, microgrid commercialization, adaption of the electric system to climate risk, and energy storage.

The initial 2012-2014 EPIC budget was $368.7 million, including a 10% cap on administrative costs. This increased modestly to $405.8 million for the 2015-2017 period. The California Energy Commission, as one of the administrators of EPIC, produces an annual report that documents investments.

Funding Levels

CES-21 funding in 2016 was $10.3 million, divided among the approximately 11.9 million customers of the three IOUs, results in a funding level of $0.87 per customer. EPIC's annual budget of $162 million translates to funding of approximately $13.61 per customer.

Insights: California is a leader in customer-funded innovation. The California CES-21 program demonstrates that enabling legislation can achieve two objectives: 1) clarifying the authority of a regulatory agency to approve RD&D expenditures by utilities and 2) establishing guidelines that a regulatory agency can apply in approving specific proposals. However, it also demonstrates that legislatures can subsequently modify their perspectives with respect to the amount and focus of RD&D. In this instance, the decision to reduce funding of the CES-21 program appears to have been caused by concerns about the proportion of the funding that was being used to fund administrative costs.

3. NEW YORK

New York supports customer-funded RD&D projects in both the natural gas and electric industries. There are several categories of funding. The seminal order establishing competition in New York's electric and natural gas industries (Order 96-12) established a non-bypassable systems benefits charge (SBC) from customers to fund research and development as well as energy efficiency investments, low-income programs, and environmental monitoring. The New York State Energy and Research Development Authority (NYSERDA) was designated in 1998 to administer the SBC funds. Prior to that time, utilities performed research and development activities that were approved by the New York Public Service Commission (NYPSC) and funded through customers' utility bills. New York's utilities continue to request and receive authorization to perform R&D activities that are approved in their rate cases.

In 2000, the NYPSC approved a surcharge intended to fund medium-to-long-term R&D by New York's investor-owned natural gas local distribution companies (LDCs) in response to a decision by the Federal Energy Regulatory Commission to phase out support for the Gas Research Institute through a surcharge on interstate pipeline deliveries.[27] New York's LDCs pledged to work collaboratively to address common needs and avoid duplication of research activities. The NYPSC relied on a Staff recommendation to have funds directed to distribution activities, and not to upstream activities (i.e., supply and storage) or to improving end-use appliances that were considered competitive activities. An appendix to the recommendation provides a list of qualifying distribution activities that includes pipe installation, pipe repair and maintenance, modeling of pipe flows, and improvements that would address environmental impacts related to the distribution function. This effort came to be known as the Millennium Fund. An industry trade group estimated that the benefit-to-cost ratio of gas R&D projects was approximately 3:1. The Millennium Fund remains in place today.

Millennium Fund programs are supplemented by utility-specific natural gas R&D programs that are approved in individual LDC rate cases. For example, Consolidated Edison proposed the deployment of trenchless technologies that allow the companies to repair gas distribution lines without digging a trench. Central Hudson has proposed to test a "non-pipes alternatives" concept as a way to meet growing peak demand on constrained parts of their system.

New York's support for innovation experienced a renaissance with its "Reforming the Energy Vision" (REV) proceeding that began in 2014. Customer-funded RD&D occurs through two mechanisms: (1) REV demonstration projects proposed pursuant to the Track 1 Order in the REV proceeding, and (2) RD&D efforts organized and managed by NYSERDA and funded by the SBC.

REV demonstration projects were filed pursuant to guidelines established in the REV Track 1 Order issued on February 26, 2015. The REV proceeding is New York's broad-based initiative to leverage technology and business model innovation in order to integrate substantial amounts of "Distributed Energy Resources" and thereby enhance reliability and resiliency while lowering carbon emissions.

Regulatory Rationale

The NYPSC expressed its support for innovation with its opening paragraph of the Track 1 Order:

The electric industry is in a period of momentous change. The innovative potential of the digital economy has not yet been accommodated within the electric distribution system. Information technology, electronic controls, distributed generation, and energy storage are advancing faster than the ability of utilities and regulators to adopt them, or to adapt to them. At the same time, electricity demands of the digital economy are increasingly expressed in terms of reliability, choice, value, and security.[28]

The Track 1 demonstration projects represent the NYPSC's commitment to supporting the realization of REV's ambitious objectives by inviting and subsequently approving customer-funded demonstration projects. Customer-funded demonstration projects were broadly supported by stakeholders, but the largest industrial customers expressed reservation about "significant" commitment of customer funds while REV concepts were still under development.[29] The NYPSC cited the following rationale for approving demonstration projects:

> *Demonstration projects will inform decisions with respect to developing DSP functionalities, measuring customer response to programs and prices associated with REV markets, and determining the most effective implementation of DER. Demonstration projects will test new technology approaches to assess value before going to scale. Data collected from these projects will inform regulatory changes, rate design, and the most effective means to integrate DER on a larger scale. Demonstration projects will also help to identify the kinds of price signal, tariff, data and consumer protection regulations necessary to bring products to scale.*[30]

As documented in our 2015 Update, the NYPSC established the following eight criteria for reviewing utility demonstration project proposals:

1. Demonstrating Innovation – Diversity of projects in the demonstration portfolio;
2. Value Distribution – Allocation of project benefits among customers, utilities and third parties;
3. Partnerships – Between utilities and third parties;
4. Customer Engagement – Response to DERs across the spectrum of customers;
5. Market Solutions – Enabling participants to propose solutions through competitive solicitations;
6. Developing Competitive Markets – Testing rules that will further the development of new markets;
7. Cyber Security – Developing data security standards and protocols; and
8. Scalability – The ability to accelerate development at scale.[31]

The five New York utilities submitted eleven demonstration projects in July 2015. These were approved on a staggered basis during the following 9-month period. Cost recovery is approved in utility rate cases, with a cap on demonstration project cost recovery at 0.5% of total revenue requirements or $10 million. The following table lists five of these projects.[32]

Table 2: Highlighted REV Demo Projects

Demo Project	IOU	Partners	Project Goals
Building Efficiency Marketplace	ConEd	Ecova Inc. and Honest Buildings	Build an online C&I marketplace to enable targeted building owners to leverage energy data and connect with qualified products/service vendors
CenHub Marketplace	Central Hudson	Simple Energy	Build an online mass market marketplace that connects customers and 3rd party DER providers with detailed home energy profiles and enhanced data analytics
Clean Virtual Power Plant	ConEd	SunPower and Sunverge	Bundle residential solar with storage offerings to aggregate and dispatch as a virtual power plant for local distribution system needs
Community Energy Coordination	NYSEG	Taitem Engineering	Aggregate and coordinate local demand for clean energy technologies through an online marketplace
Flexible Interconnect Capacity Solution	NYSEG	Smarter Grid Solutions	Provide cheaper/faster large scale DER interconnections with infrastructure-as-a-service model

These projects are supplemented by electric RD&D projects in rate cases. National Grid has requested approval for a number of demonstration projects that examined the value of data analytics, changes in workflow and business processes, and the use of mobile device applications by employees. They also proposed electric heat and electric transportation demonstration projects.

In a recent National Grid rate case, the Commission explained: “Although, to date, we have not adopted REV programs expressly targeted to our natural gas utilities, we support economically viable projects to the extent that they advance REV goals and benefit the gas system.”[33] In this spirit, National Grid and Con Edison have both proposed natural gas demonstration projects in their rate case filings to align with the goals of REV. The Commission approved National Grid’s three demonstration projects that aim to create a smarter and more resilient gas network while also encouraging customer engagement and helping to achieve the goals set out in REV. These projects consist of technology packages to test behaviors and response to energy efficiency options, assessing the effectiveness of generating units in load reduction, and a commercial demand response program to test market incentives. In Con Edison’s most recent rate case (case 16-G-0061), the company emphasized how AMI deployment will help build the smart grid of the future as envisioned in REV. Con Edison has also recently proposed the Smart Solutions for Natural Gas Customers Program, which aims to decrease gas usage, procure alternative resources, and contribute to State environmental goals. The proposal also includes a Gas Innovation Program, aimed at testing new business models for clean heating technologies in order to determine if the technology could be scaled for a greater impact.[34]

A third category of RD&D projects in New York is either funded by NYSERDA or hosted on a recently launched REVConnect web-based platform. NYSERDA is interested in demonstration projects that test REV concepts, particularly those involving new business models that will provide revenue and earnings opportunities for utilities and third parties. These projects will test the willingness of customers to engage with – and pay for – new products and services that are delivered in an innovative manner. Ideally, proposed projects are scalable if they prove to be promising.

The REVConnect platform (https://nyrevconnect.com) brings utilities, third parties, investors, and regulators together to develop innovative solutions, and the REVConnect team serves as a facilitator to promote collaboration.

Interview Insights[35]

Policy makers were particularly interested in demonstrating that the industry could transition to a new business model without having an adverse impact on reliability. NYSERDA recognizes that utility participation in RD&D is critical to the ultimate goal of new technologies and business models being deployed for the benefit of customers who are funding the research through the SBC. There is a tension between the uncertainty and risk associated with RD&D and the cost-benefit analysis that regulators typically apply to more traditional utility investments. The longer timeframe associated with returns to RD&D also present a challenge as regulators are generally looking for some measurable customer or environmental benefit (e.g., a specified carbon reduction quantity) within the first five years. Although NYSERDA is a state agency, its budget and activities are subject to review and approval by the NYPSC. As part of the Clean Energy Fund review, NYSERDA has received approval to apply a ten-year business planning horizon to its portfolio of programs. NYSERDA will file annual, rolling updates to its portfolio, adjusting priorities in response to technology and market developments, and defunding programs that no longer appear promising. This longer horizon is more aligned with the risk associated with RD&D, and also provides greater certainty and continuity as the NYSPC grows more comfortable with NYSERDA's portfolio approach.

The New York approach to innovation requires that the NYPSC apply a different perspective to its review and oversight of RD&D than it takes to its more traditional approval actions. The Commission is being asked to adopt a higher risk tolerance on behalf of customers based on the belief that customers will benefit in the long run from innovation and that, absent customer-funding, a suboptimal level of RD&D will occur in the regulated utility segment.

Funding Levels

Cap on REV demonstration project cost recovery of 0.5% of total revenue requirements, or $10 million per year.

Insights: New York has promoted utility innovation through multiple programs targeting both the gas and electric industries. While New York policy makers are pressuring the utilities to be innovative, they are also keeping utilities firmly within a cost-of-service regulatory environment. The introduction of potentially disruptive market and regulatory models is a concern among utilities as DERs continue to be integrated throughout the state. The issue may be brought to a head with NYSERDA taking a more active policy role in an effort to sustain the momentum toward increasing innovation.

4. MINNESOTA

Minnesota has two initiatives that provide customer-funded RD&D projects: a Renewable Development Fund established in 1994, and a more recent effort to develop demonstration projects through extensive stakeholder participation as part of Minnesota's e21 initiative. This initiative is addressing the future of energy market more comprehensively by examining changes to business models and regulatory frameworks necessary to leverage new technologies to promote a sustainable future with greater reliance on customer-sited and other renewable energy supplies.

a. Renewable Development Fund

The Minnesota Legislature established the Renewable Development Fund in 1994 as part of a condition that allowed Xcel Energy, Minnesota's largest electric utility, to store spent nuclear fuel in dry casks at the Prairie Island nuclear generating plant site. The legislation required the utility that operates the Prairie Island nuclear generating plant (Xcel Energy) to transfer $500,000 per year for each cask being used to store spent nuclear fuel into a fund that could only be used to develop renewable energy sources. This same legislation required Xcel Energy to spend 2 percent of its annual revenue requirements on energy conservation improvements. Funding requirements have been amended by legislation as on-site storage needs continued to grow, increasing to $25.6 million by 2016. Xcel Energy must file an annual report to the legislature listing each project and its projected financial benefit for customers. RDF is funded by a surcharge to Xcel Energy's Minnesota and Wisconsin customers. A typical Minnesota customer pays 0.1034 cents per kWh or $0.76 per month for the program.[36]

Regulatory Rationale

The RDF's objective is to remove barriers to entry for renewable energy technologies, including economic barriers from competing against conventional energy sources.[37]

Specifically, the RDF is allowed to fund:

- Increasing market penetration of renewables;
- Promoting start-up, expansion, and attraction of renewable projects in Minnesota;
- Stimulating in-state R&D into renewable electric energy technologies; and
- Developing near-commercial and demonstration scale renewable or infrastructure products.

The funds are allocated either as designated by the legislature or to energy production projects (biomass, hydro, solar, and wind) or research programs that are recommended by a stakeholder group to Xcel Energy and the Minnesota Public Utilities Commission (MPUC). Up to $10.9 million annually must be allocated to support renewable energy production incentives through Jan 2021 with over 85% of this targeted for wind energy facilities.

As reported in Xcel Energy's 2017 annual report to the legislature, the RDF program has funded over $276 million in renewable energy projects since its inception. The majority of this spending provides direct support to projects that produce renewable energy or to customers that are securing solar power. However, the RDF has also supported $52.5 million to 181 R&D projects that have produced research papers, funded workshops, and supported patent applications. Examples of ongoing or recent R&D projects are provided in Table 3.

Table 3: Highlighted RDF-Funded Projects

	Project Name	Funding	Resource	Description
1	University of Minnesota (Dairy)	$982,408	Solar/Wind	Model a "net zero" energy dairy parlor at the West Central Research and Outreach Center by integrating 20 kW wind and 54 kW solar with storage.
2	University of Minnesota (Biomass)	$819,159	Biomass	Evaluated economic and technical issues related to biomass fuel and integrated gasification combined cycle technology.
3	University of Minnesota (Torrefaction)	$1,899,449	Biomass	Demonstrate a prototypic torrefaction bioconversion process and distributed electric generation.
4	West Central Telephone Association	$137,000	Wind/Solar	Designed and tested configurations and specifications of a hybrid wind/solar power system for distributed generation in remote locations.
5	University of Florida	$999,995	Biomass	Demonstrated two-stage anaerobic digester at American Crystal Sugar in Moorhead, MN to generate methane for conversion to electricity.
6	Xcel Energy	$1,000,000	Wind	Installed a 1.0 MW sodium sulfur battery adjacent a wind farm to validate the value of energy storage for greater wind energy penetration.
7	University of Minnesota (Noise)	$625,102	Wind	Research the sources and quality of wind turbine sound and the thresholds of potential health impacts on humans.
8	University of St. Thomas	$2,157,215	Solar/Wind	Install a 0.25 MW peak, multi-purpose microgrid in Chicago City to establish an Engineering Senior Design Clinic for microgrid research and testing.
9	SarTee Corporation	$350,000	Biofuel	Researched the growth of algae fed on CO2 from flue gas and extracted the algae oils for conversion into a marketable biodiesel product.
10	Windlogics	$997,000	Wind	Defined, designed, built and demonstrated a complete wind power forecasting system.

The largest of these projects is the microgrid project at the University of St. Thomas, including 50kW each of solar capacity, wind, biodiesel generators and energy storage.

b. e21 Stakeholder Initiative

The e21 initiative is funded by the Minnesota-based McKnight Foundation that brings together energy industry stakeholders in an effort to develop a future business model and regulatory framework that better align utility financial objectives with public policy goals. The e21 initiative has produced Phase I (2015) and II (2016) reports and is currently engaged in a third and final phase that focuses on demonstration projects. As part of the third and final e21 phase, Xcel Energy has consulted with stakeholders to develop a pilot program for time-of-use rates. The initial filing for this pilot was completed in November of this year, and estimates the total pilot cost to be $8 million in capital and $2.9 million in O&M. If the project is approved, Xcel will seek to recover the majority of these costs through the annual Transmission Cost Recovery (TCR) Rider. The pilot provides participants with increased information and support, and seeks to shift load away from peak times in order to reduce or avoid the need for system investments in fossil fuel plants. The filing cites the Minnesota Legislature's Grid Modernization Statute, which directs utilities to identify investments that modernize the grid and authorizes the Commission to certify these projects. The utility may then seek cost recovery for these projects under the TCR rider.[38]

A second project, developed as a partnership between Seventhwave and Lawrence Berkeley National Laboratory (LBNL), would evaluate alternative performance-based regulatory frameworks. Finally, the MPUC has directed Xcel to develop a 400 MW demand response pilot program.[39]

Interview Insights[40]

The e21 approach to innovation tests the value of including stakeholders in the design and development of demonstration projects, particularly when the objective is to test a new business model or a new way for utilities to work with third-parties, or when the demonstration project is testing the engagement and responsiveness of customers to new products and services. Although specific demonstration projects still need to be reviewed and approved by the MPUC, the stakeholder experience improves the design of the projects and increases their eventual likelihood of success. Stakeholders engage directly with the utility throughout this facilitated process and are in a position to support regulatory approval, including ratepayer support. The benefits of improved stakeholder relationships can carry over to more controversial utility regulatory matters that employ stakeholder engagement, including integrated resource planning efforts. This type of engagement has the potential to reduce regulatory risk and regulatory lag that is exacerbated by lengthy litigation.

One byproduct of the e21 Initiative is legislation that codifies the authority of MPUC to approve multi-year rate plans, extending the maximum from 3 to 5 years, and requires any such plan to include a distribution system plan.[41] This legislation, the 2015 Jobs and Energy Bill, also provides the MPUC with the authority to develop performance metrics for utilities.[42] The identification of measures, specific metric definitions, and targets all benefit from stakeholder engagement outside of a more rigid litigation process. Thus, the e21 Initiative has effectively created a role for itself that complements rather than competes with the more traditional relationship among the regulator, utilities, and stakeholder intervenors. The issues faced by utilities and their regulators are expected to become increasingly complex as energy business models continue to evolve in response to technology and market developments.

Funding Levels

For the RDF, there is a $25.6 million annual contribution to the fund. In 2017 the RDF charge for a typical customer was $0.76 per month, equaling $9.12 per year.

Insights: Minnesota, with the e21 initiative, is increasing the likelihood that regulators will be willing to approve customer-funded innovation by increasing the degree of collaboration between the utilities and stakeholders, and by beginning the collaboration while the demonstration projects are still in the design phase.

5. AUSTRALIA

The Australian Energy Regulator (AER) is beginning to respond to changes in the energy industry and the role of behind-the-meter resources as it faces rising peak demands. The AER proposed a demand management incentive scheme (DMIS) and demand management innovation allowance (DMIA) to encourage utilities to manage demand more proactively. The AER released a draft decision on the DMIS and DMIA in August of 2017 and finalized the decision that December.[43]

The DMIS is ongoing and will give electric companies a stronger incentive to undertake expenditures on demand management options. It benefits the grid and gives consumers more opportunities to earn money from managing their demand by making it more financially attractive for network businesses to use demand management. For example, customers may rely on their solar panels and batteries to trade electricity on a local energy exchange.

The DMIA supplements Australia's existing incentive based regulatory framework. The program is dedicated to specific projects and will provide funding for R&D on demand management projects that have potential to reduce long-term costs. The innovation allowance continues to reduce the risk that utilities currently face when investing in R&D activities. Customers contribute to the fund through an increment in each distributor's revenue requirement according to the formula: $200,000 plus 0.075% of the applicable maximum allowed revenue requirement.[44] Projects must satisfy at least one of three criteria to be funded:

1. Based on new or original concepts,
2. Involves technology or a technique not previously implemented in the National Electricity Market (NEM), or
3. Focused on customers in a market segment that has not been exposed to the technology.

Distributors must file an annual report that identifies the funding for all projects. Subsequent project-specific reports will describe the methodology and outcomes.

In describing the background for the mechanism, the AER cites a July 2017 report prepared by Energy Networks Australia (ENA),[45] an industry association, with support from the Energy Consumers Association.[46] The AER highlights the unique role that distributors play in addressing the challenges to distribution operations from integration of intermittent generation and distributed energy resources. The DMIA rationale addresses regulatory barriers directly, noting that regulated utilities have a lower incentive to conduct R&D than competitive businesses because they:

- Face lower 'up-side risk.' Competitive businesses may be more likely to profit from R&D than monopolies as R&D can provide them with a 'competitive advantage.' Moreover, to the extent that R&D results in future cost reductions, distributors will pass a material portion of these gains onto electricity consumers under [the] regulatory regime.
- Still face 'down-side risk.' If R&D costs occur significantly before the benefits, distributors risk being financially penalized from making these decisions under the regulatory regime.[47]

The ENA report, "Network Innovation: Discussion Paper" describes the barriers to innovation at great length. It observes that the proposed DMIA applies only to the electricity industry and not to the natural gas distributors. It cites two industry reports that address the immediate challenges and future role of technology in both the electricity and natural gas industries.[48] The report identifies several regulatory barriers including the fact that RD&D projects cannot satisfy traditional pre-approval investment tests and the mismatch between the relatively high risk of innovation and low regulated returns. The report notes that the benefits of innovation typically accrue over a longer-term than traditional investments, reinforcing these risks and financial barriers.[49]

The ENA report also points to the potential role for innovation in the gas sector. "Similarly, innovation will play a key role in realizing opportunities for further decarbonizing Australia's gas sector. There is a strong potential to use three transformational technologies - biogas, hydrogen and carbon capture and storage – to create clean, dispatchable energy resulting in zero emissions that can use existing gas networks' infrastructure."[50] Pointing to the gap it sees in the scale of investment required to achieve this potential, the ENA cites industry-led initiatives, including Energy Networks Australia's Gas Committee innovation fund established in 2016 for targeted R&D and technical activities in industry-identified priority areas.[51]

The AER has also addressed the issue of which services should be provided by regulated distributors (DNSPs), and which should be open to competition through a "ring-fencing" set of guidelines. The objectives of these guidelines, as illustrated by those established for electric distributors, are designed to prevent:

- Cross-subsidizing an affiliate's services in contestable markets with revenue derived from its regulated services
- Discrimination in favor of a DNSP's related electricity service provider operating in a contestable market
- Providing related electricity service providers with access to commercially sensitive information acquired through provision of regulated services
- Restricting access of other participants in contestable markets to infrastructure services provided by the DNSP, or providing access on less favorable terms than to its related electricity service providers.

According to the AER: "The Guideline sets out the obligations a DNSP must meet to separate its regulated monopoly services from any services it may seek to offer to contestable markets. We expect the Guideline will aid development of competitive markets where competition is feasible and support efficient, incentive-based regulation of monopoly networks where competition is not feasible."[52]

Interview Results[53]

The driving forces impacting utility regulatory policy in Australia are consumer concerns regarding energy prices, reliability concerns, pending retirements of coal-fired plants and the growing penetration of renewables. The existing regulatory model is a multi-year incentive program. Companies come in every five years with forecasts for the next five years. The regulator, with technical advisors, determines if the forecast reflects "efficient costs," and then sets revenue for five years. The underlying rationale is if the utility can improve on costs, they retain the difference, and if there is a non-network alternative that's more cost-effective, the utility has the incentive to look at that alternative.

Regulatory Rationale

Despite these incentives, the AER has found it challenging to move utilities beyond a perceived focus on capital investments, and prior incentives have not been sufficient to overcome that hurdle. There is a cultural resistance. The AER is attempting to promote innovation through the DMIA and also wants to distinguish between services that should remain under regulation, and those that should be competitive, as described in its ring-fencing guidelines.

The AER is seeing more partnering between the networks and different innovators, and the networks are becoming more open to innovation. The AER sees its role as setting up a framework, and the industry is responding. The AER is also emphasizing a movement away from an adversarial relationship to a more collaborative model. Pilot projects are beginning to illustrate scalability. Tesla, for example, is building a 129-MWh battery with French energy company Neoen in South Australia, characterized as the world's largest battery.

Australia also funds RD&D projects as a result of the ARENA Act 2011, which targeted $2 billion (Australian dollars, equal to approximately $1.97 billion Canadian dollars) to invest in renewable energy and the Australian renewable technology sector. Funding has been modified by the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 and Budget Savings (Omnibus) Bill 2016.

Funding Levels

DMIA funding is AU$200,000 plus 0.75% of annual revenue requirements (ARR). DMIS funding is up to 1% of ARR.

Insights: Australia is poised to implement customer-funded innovation mechanism at a meaningful level. This proposal is broadly supported by stakeholders who recognize that utility innovation is part of the solution to adapt to a changing environment. This includes targeting a combination of energy costs, reliability, and the integration of renewable energy resources. A combination of government-funded, customer-funded and industry-led mechanisms are being utilized.

6. ONTARIO

Ontario currently funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers.

More recently, the provincial government of Ontario and its energy regulator have increased their attention on the role that innovation needs to serve in the energy sector. The Ministry of Energy's 2017 Long Term Energy Plan (2017 LTEP), released in October 2017, devotes an entire chapter to innovation.

Regulatory Rationale

Ontario is focused on maintaining affordable energy for residential and business customers. Innovation in the delivery of electricity and natural gas, greater customer choice, and expanded access to natural gas, are viewed as major contributors to realizing this goal. The emphasis on innovation responds to stakeholder input that "electricity costs are too high," the Ministry should "consider new technologies and methods to manage energy use," and there is a need to "expand access to natural gas."[54] The Ontario Energy Board's (OEB) 2017-2020 Business Plan identifies "technological innovation that presents new choices for consumers and challenges traditional business and regulatory models" as one of four key trends that define the current environment.[55]

The 2017 LTEP projects that innovation in the natural gas sector will increase Ontario's reliance on renewable natural gas, leveraging the Waste-Free Ontario Act 2016 and the Organic Waste Action Plan that promote the use of organic waste to produce natural gas. The Government of Ontario intends to work with the Independent Electricity System Operator (IESO) on a pilot program to transform electricity into hydrogen gas that can be used for traditional and new transportation end-uses.

Technology innovation in the electricity sector will focus on three areas:

1. Employing technologies to modernize the electricity network, increasing automation, addressing cybersecurity issues, and enabling transactive energy markets;

2. Integrating distributed energy resources (DER) including energy storage to help customers manage their energy end-use (frequently referred to as "Smart Home" initiatives); and

3. Electrification of the transportation sector.

The 2017 LTEP calls for pricing innovation that would test alternative time-varying pricing approaches, leveraging smart technologies and communications as well as consideration of net energy metering policies.

There are innovative uses for natural gas as well in Ontario, as discussed in the 2017 LTEP. Renewable natural gas (RNG) is seen as innovative in that it is a low-carbon fuel that can use the existing distribution system to replace conventional natural gas. Along this same vein and in connection with Ontario's Climate Change Action Plan, the government is developing a pilot program that will allow agricultural sectors to produce RNG and will support businesses in using RNG for vehicles. Power-to-gas, transforming electricity to hydrogen gas, is seen as another potential innovative link between Ontario's electricity and natural gas systems. Recognizing the versatility of this fuel, and the fact that it is a way to decarbonize the natural gas supply, Ontario is undertaking a feasibility study of fueling passenger trains with hydrogen. The government will also work with the IESO to explore the energy system benefits and GHG emission reductions that could result from using electricity to create hydrogen.[56]

The LTEP acknowledges that there are currently several barriers to innovation, and stakeholders are indicating a need for government funding support for R&D, including enhanced funding of the existing Smart Grid Fund. Ontario's $50 million Smart Grid Fund was launched in 2011 to assist local distribution and smart grid companies test and build the technologies needed for grid modernization. Nonetheless, the report notes that there has been uneven investment in grid modernization, citing an Electricity Distributors Association finding that "half of Ontario LDCs still approach innovation in a gradual or incremental way," before concluding:

> *It is clear that barriers to innovation remain. With the rapid development of new technology and the increase in customer expectations, the time to address these barriers is now. To encourage change in the energy sector, the government will work with utilities and other partners to build a culture of innovation, and will look to the OEB to explore, where cost-appropriate.*

The report identifies specific barriers, including three regulatory framework barriers:

1. The regulatory treatment of LDC capital and operational expenditures, which can inhibit the uptake of these non-wires solutions;
2. A cost-benefit framework that provides clarity on the treatment of investments, such as those with localized costs that provide benefits to other electricity system participants (also known as the diffuse benefits issue); and
3. The ability of utilities to make non-traditional distribution system investments and participate in market opportunities that would ultimately reduce ratepayers' costs associated with capital or other investments.

As noted by the Ministry, the OEB will play a key role in addressing these and other barriers to utility innovation. The OEB's business plan cites many of the same industry drivers, trends, and objectives as the 2017 LTEP. These include the need for utilities to integrate increasing numbers of DER, including electric vehicles and microgrids. The OEB is working on a 2018 roadmap for regulatory reforms needed to take advantage of technology innovation and new rate designs that will support efficient use of distribution networks.

Interview Results[57]

Ontario funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers. Recent demonstration projects that have been funded through this mechanism include several pilot programs that test TOU and other pricing mechanisms (often combined with energy management system technologies). They also include testing new energy technologies such as energy storage and the potential for solar power to defer infrastructure investments.

Stakeholders involved generally understand the goals: be cost effective, make the customer's voice heard, and meet environmental policy goals. An outcomes approach to regulation is compatible with these objectives. The OEB perceives a hangover of existing habits and approaches to distribution planning, and some prior regulatory features that do not provide adequate incentives for least cost systems. Incentives that align customer and utility objectives will drive down system costs. The OEB has also relied on moving more distribution charges to the fixed customer charge to remove barriers to innovation.

Governance for pilot projects includes the OEB establishing guidelines, followed by interim reports showing results based on the sample (e.g., how effective is it at demand response and consumer elasticity), followed by a mandatory final report. Monthly monitoring reports are sometimes utilized in the first period, followed by bimonthly reports.

Insights: Ontario is supporting customer-funded innovation through a broad-based customer-funded mechanism collected through the ISO. The strong positioning of the role of innovation in addressing energy costs in Ontario by the Ministry is important in reaching alignment with the OEB to provide support for innovation. The 2017 LTEP and OEB business plan recognize that regulatory barriers need to be addressed. The regulator is seeking to better align utility and customer interests and the regulatory model through demonstration projects and incentives that will ultimately deliver lower energy costs.

7. MASSACHUSETTS

In 2014, the Massachusetts Department of Public Utilities (DPU) issued an order on electric grid modernization, requiring each utility to file a Grid Modernization Plan (GMP). The order supports utility innovation and directs each of the Commonwealth's three investor-owned utilities (National Grid, Eversource, and Fitchburg Gas & Electric) to propose a list of projects that focus on testing, piloting, and deploying RD&D projects that modernize the grid and employ new technologies. The DPU invited the utilities to propose funding mechanisms as part of their GMP filings, clearly inviting customer-funded proposals. However, the DPU also directs utilities to leverage outside funding and pursue collaboration to the extent possible.[58]

Regulatory Rationale

Notably, the DPU indicated that it would not deny cost recovery "merely because of lack of success," responding directly to one of the major barriers to utility innovation, noting further that the DPU had not been supportive of RD&D projects in the past, and signaling an intent to reverse existing precedent. Grid modernization would result in lower energy costs by contributing to a less expensive electric system (investments, operations and maintenance expenses), reducing peak demands, and by providing customers with tools that they could employ to reduce their electricity usage, particularly during price spikes.

The DPU cited increasing reliability, lower energy bills, and clean energy as grid modernization goals. Increases in reliability and resiliency would be supported by "a range of grid modernization technologies and policies." [59] The DPU's order expressed a clear preference for advanced metering functionality (AMF) which would enable time-varying pricing mechanisms.[60] Clean energy is another factor cited by the Department in support of its grid modernization initiative:

> *The modern electric system that we envision will be cleaner, more efficient and reliable, and will empower customers to manage and reduce their energy costs. The modern electric system will build on the Patrick Administration's progress towards our clean energy goals by maximizing the integration of solar, wind, and other local and renewable sources of power.*[61]

The utilities filed their GMPs in August 2015, in compliance with the DPU policy directives. For example, National Grid proposed to fund its grid modernization RD&D efforts through an RD&D provision in a new tariff, identifying $29.3 million that it proposes to pursue through the grid modernization RD&D program over the next decade. National Grid pledges to continue to leverage RD&D investments by joining with other utilities (through industry organizations or other means) to seek to fund work that, by itself, would be too expensive for a single utility and to seek outside funding.

The DPU review of the grid modernization filings was put on hold after the election of a new Governor in November 2015, and subsequent appointment of a new Chair. This is not uncommon when there is a change in administration, particularly when there is also a change in party, as in this case. The entire Commission has now turned over. Hearings were held this past summer, and the parties have filed initial and reply briefs.

Eversource filed a five-year performance-based regulation proposal earlier in the year, proposing to roll-in its grid modernization investments as part of its rate plan. In an order dated November 30, 2017, the Department declined to address grid modernization and indicated that it preferred to consider the three plans together in the grid modernization dockets to allow time for a more thorough examination and enable the DPU to establish consistent policy across the utilities with respect to cost recovery and other issues. The DPU noted the level of uncertainty associated with both costs and anticipated benefits, and its intention to ensure that grid modernization investments will produce an optimized level of net benefits.[62] The DPU did signal its intent to apply the standards established by the prior Commission in the grid modernization policy proceeding.

The DPU, however, made two exceptions that it deemed to be consistent with existing precedent. First, it approved funding of $55 million for Eversource's two energy storage demonstration projects, finding that they will facilitate the market for energy storage in Massachusetts and provide data that will be critical in evaluating future energy storage deployments as part of Massachusetts' clean energy future. The Department found that the proposed energy storage demonstration program is consistent with the grid modernization objectives of integrating distributed resources and improving asset management.

Second, the DPU approved $45 million to fund EV charging stations and customer education and outreach, noting that these investments will help accelerate electric vehicle charging infrastructure development in Massachusetts, encourage electric vehicle purchases, and contribute to greenhouse gas emissions reductions in the Commonwealth.

Funding Levels

As an example, the recent approval of Eversource's storage and EV projects includes approved capital investments of $100 million. The annual revenue requirements associated with these investments will be recovered from Eversource's 1.4 million electric customers in Massachusetts. The Department considered bill impacts, net of customer benefits, when approving these spending levels.

Insights: Although the DPU has not yet issued orders in the grid modernization cases filed over two years ago, the Eversource order signals its intention to apply the policies from the prior Commission and its willingness to fund demonstration projects that advance the public interest. Most importantly, this qualifies as customer-funded innovation. It will be a few years before these recently approved projects will produce results that can be evaluated. The funding for Eversource's storage and EV projects coincided with approval of its PBR plan, indicating innovation and PBR can be pursued simultaneously.

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8. BRITISH COLUMBA

Legislative Rationale

British Columbia, through a series of legislative actions, has established aggressive goals for its energy sector that depend on investments in clean energy production and infrastructure as well as technologies that support energy management activities. Many of these programs are funded through surcharges on energy usage.

The 2007 Greenhouse Gas Reduction Targets Act set initial targets for reductions in greenhouse gas ("GHG") emissions at a 33% reduction by 2020 and 80% by 2050, and established a carbon tax. The 2010 Clean Energy Act (CEA) set goals with respect to electricity self-sufficiency, including reducing the expected increase in electricity demand by at least 66% by 2020, generating at least 93% of electricity from clean or renewable resources, supporting the development of innovative technologies that support the conservation and clean energy goals, and reducing GHG emissions dramatically by 2050.

The CEA directs the British Columbia Utilities Commission to set rates as necessary to allow utilities, including British Columbia's largest electric utility, provincial-owned BC Hydro, to recover the costs they incur to achieve these goals. The Greenhouse Gas Reduction Regulation ("GGRR"), authorized under the CEA, allows for utilities' prescribed undertakings that work towards GHG reductions, while still allowing them to recover their costs through utility rates. The GGRR allows utilities to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. British Columbia's utilities have provided incentive funding to customers to support development of CNG and LNG fueling stations, vehicle and marine vessel conversions, and the use of renewable natural gas.

One fund that is instrumental in achieving British Columbia's goals is the Innovative Clean Energy (ICE) Fund administered by the Province's Ministry of Energy, Mines and Petroleum Resources. The ICE Fund is a legislated Special Account designed to support the Province's energy, economic, environmental and greenhouse gas reduction priorities, and to advance B.C.'s clean energy sector. The ICE Fund was initially funded by a 0.4% levy on the final sales of electricity, natural gas, fuel oil and grid-delivered propane. The electricity levy has since been removed with the reinstatement of the Provincial Sales Tax on April 1, 2013.

British Columbia is interested in demonstrating the commercial viability of new technologies as an economic development program, with successful capabilities potentially being exported to other markets. In March 2017, the Province announced a $40 million partnership with Sustainable Development Technology Canada to support the development of pre-commercial clean energy projects and technologies. The parties will conduct a joint call over a three-year continuous intake period to seek out clean energy projects and technologies that will mitigate or avoid provincial greenhouse gas emissions, including prototype deployment, field testing and commercial-scale demonstration projects. Projects must take place in British Columbia and must demonstrate how the proposed project will result in GHG reductions, commercialization, and economic growth in British Columbia and Canada.

FortisBC has a Smart Learning Thermostat Pilot Program for both natural gas and electricity customers that is designed to test customer engagement and energy savings. FortisBC offers a renewable natural gas service that has attracted 9,000 customers. BC Hydro has invested in a $12.5 million project to test the ability of grid storage to support reliability in remote areas of its distribution network. British Columbia's clean electric vehicle (CEV) program provides additional funding to meet growing demand for rebates on vehicles and specialty-use vehicles, and supports the expansion of charging stations, hydrogen fueling stations, and the development of new research and training programs. Both BC Hydro and FortisBC are building EV charging infrastructure to support growing demand in this sector.

Interview Insights[63]

A series of legislative and policy initiatives led to the establishment of the Clean Energy Act in 2010, and the subsequent GGRR in 2012. Under this legislation, utilities have the option to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. The Province does not contribute any funding. The programs are fully funded by natural gas utilities and paid for by natural gas customers.

The GGRR has been amended over time to allow utilities to implement specific undertakings. In November 2013, amendments were made to allow utilities to expand their incentives to include trains and mine-haul trucks, and to provide tanker-truck delivery services to trucking, mining and marine-transportation customers. In May 2015, the Government further amended the GGRR to allow for shifts in the allocation of incentives and investments within the previously-approved total spending cap in order to better respond to changes in the marine market place. Amendments made in early 2017 enabled utilities to increase natural gas distribution to the marine transportation sector. Amendments also increased incentives for using RNG in transportation and established a Renewable Portfolio Allowance to increase the supply of RNG.

Concerns in BC have been expressed that these services might be offered by unregulated industry in a competitive market (e.g., LNG and CNG), and should not be supported by innovation funding because this would provide the utility with an "unfair advantage." Amendments to the legislation have been justified on the basis that utilities are serving a market that would likely not be served by competitive service providers. Utilities may also ask for incentives to execute innovative programs, particularly where a competitive procurement process is employed and overseen by an independent third-party "fairness advisor."

Utilities provide comprehensive reports on these initiatives to the provincial government and the commission.

Insights: In British Columbia, an ambitious clean energy policy has provided flexibility for utilities to propose - and the regulator to allow - cost recovery for customer-funded innovation investments. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

CONCLUSIONS

REGULATORY RATIONALE

Several policymakers, including utility regulators, have recognized the need for utilities to actively contribute to innovation in the electricity and natural gas sectors of the economy and the value this provides to customers. This report focuses on jurisdictions that provide customer funding for innovation and the reasons that regulators have cited in approving this funding. They have approved funding for demonstration projects that explore new business models, pilot technologies that result in delivery efficiencies, test new products and services, and support scalable investments. All of these investments help accelerate the pace of change in the sector.

Goals for these programs vary by jurisdiction, but common themes include: greenhouse gas reductions, lower energy prices, demand reduction or load shifting, accelerated deployment of renewable and distributed resources, improved system reliability, and the introduction of new utility technologies. Rationales also vary according to specific circumstances and preferences of regulators and policymakers. Ofgem sees innovation funding as a vehicle for driving cultural change at utilities, and necessary to achieve these objectives. California and BC see innovation as a mechanism for economic development. BC and Australia see innovation as a path for stimulating competitive service offerings. Ontario and Massachusetts emphasize new choices for consumers.

There is a growing recognition that customers are long-term beneficiaries from innovation in the utility business model, so investments on their behalf are justified and in the public interest. Customer funding for innovation-related projects is often applied in conjunction with funds that are contributed by government and third-party vendors.

MEASURING THE BENEFITS

The history of utility customer-funded innovation funding is relatively recent, so data on the benefits of these programs can be difficult to quantify. Successful deployment requires regulatory flexibility and appropriate governance to ensure the trade-offs between costs and impacts on rates are justified. Given the global nature of these policy objectives, the opportunity exists for lessons learned to be shared among regulators and industry stakeholders.

While not all demonstration projects successfully prove out a new technology or business model, these investments frequently prove to be gateways to new utility models, short-term accelerators to competitive service offerings, or some combination of quantitative and qualitative benefits. The potential gains from adaptation of new technologies and business approaches to a “mature” industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits of customer-funded innovation justify the costs.

APPENDIX: Interview Subjects and Outline of Questions

INTERVIEWEES

UK | Jonathan Morris and Neil Copeland, both of Ofgem

New York | Bryan Berry, of NYSERDA

Minnesota | Rolf Nordstrom, of Great Plains Institute

Australia | Paula Conboy, of the Australian Energy Regulator

Ontario | Ceiran Bishop, of the Ontario Energy Board

British Columbia | Paul Wieringa and Jennifer Davison, both of British Columbia Government

QUESTION OUTLINE

A Q&A with Key Regulators & Policymakers on the process from conception to reality on their innovation levy, discussing:

1. The history and how it came to be
    - Was this led by the utility industry, political class or the economic regulator or some combination thereof?
    - What was the gap that needed to be filled?
2. What challenges the regulators faced;
    - Challenges from interveners
    - Information challenges
    - Political challenges
3. What was the rationale/justification (e.g., legal, market, financial or economic) for approving the program? Or, was there a gap in the market that was viewed to be filled effectively by the regulated utility?
4. How the regulator is kept informed/engaged in how the money is spent and the overall governance structure established;
    - What are the KPIs?
    - Is there an annual or semi-annual review?
    - How are the approved funds set aside (deferral account or other?)
5. How they think the program is working;
    - What, if anything, would be considered an improvement to the current design?
6. Results achieved – have they been measured?
    - Who measures them – third party, the utility or other?
    - What if there is an underperformance?

END NOTES

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[1] Office of Ratepayer Advocate, Policy Position on CES-21: See http://www.ora.ca.gov/general.aspx?id=2422

[2] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 2.

[3] Massachusetts - Eversource spending represents costs of recently approved electric vehicle and energy storage projects. The UK NIC Electric is decreasing funding from £90 million to £70 million – this decrease is not reflected in the chart. UK NIA funding uses SGN Scotland and SGN Southern NIA expenditure as an example. New York data represents NYSERDA funding for the most recent year (significantly lower than the previous year as a result of a funding mechanism logistical change), plus ConEd funding for REV Demo projects. Australia DMIA funding is based on an average of hypothetical allowance of selected companies. Sources: AER Determinations Attachments 1 – annual revenue requirements; CES-21 Annual Report 2016; Ofgem, RIIO-GD1 Annual Report 2015-16; Ofgem, The Network Innovation Review: Our Policy Decision, March 2017; Xcel Energy, RDF Annual Report 2017; CA IOU websites; NYSERDA Financial Statements March 2017; New York DPS Order in Case 16-E-0060; Massachusetts DPU 17-05 Order.

[4] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 1.

[5] Pöyry, *An Independent Evaluation of the LCNF*, October 2016, at 78. See https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf

[6] Pöyry, *An Independent Evaluation of the LCNF*, October 2016, at 2.

[7] Ofgem, *RIIO: A New Way to Regulate Energy Networks: Final Decision*, October 2010. See https://www.ofgem.gov.uk/ofgem-publications/51870/decision-docpdf

[8] Ofgem, *Decision and Further Consultation on the Design of the Network Innovation Competition*, September 2, 2011, at 4. See https://www.ofgem.gov.uk/sites/default/files/docs/2011/09/nic-consultation.pdf

[9] Ofgem, "Innovation in Energy Networks: Is More Needed and How Can This Be Stimulated?" Working Paper, 2009, at 11. See: https://www.ofgem.gov.uk/sites/default/files/docs/2009/07/rpi-x20-innovation-working-paper_final-draft_0.pdf

[10] Ofgem, *Electricity Network Innovation Competition Governance Document*, February 1, 2013, at 5. See https://www.ofgem.gov.uk/ofgem-publications/53526/spnic-pdf

[11] Ofgem, *Decision and Further Consultation on the Design of the Network Innovation Competition*, September 2, 2011, at 2.

[12] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 43. See https://www.ofgem.gov.uk/system/files/docs/2017/03/the_network_innovation_review_our_policy_decision.pdf

[13] Ofgem, *Factsheet 93: RIIO – A New Way to Regulate Energy Networks*, October 4, 2010. See https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf

[14] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 2.

[15] Ofgem, *Factsheet 93: RIIO – A New Way to Regulate Energy Networks*, October 4, 2010.

[16] Ofgem, *RIIO: A New Way to Regulate Energy Networks: Final Decision*, October 2010, at 42. See

[17] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 9.

[18] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 37.

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[23] Ofgem, *Infographic: The energy network*, 28 September 2017. See https://www.ofgem.gov.uk/publications-and-updates/infographic-energy-network

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[28] New York Public Service Commission, Case 14-M-0101, Track 1 Order, February 26, 2015 at 1. See http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101
[29] New York Public Service Commission, Case 14-M-0101, Track 1 Order, February 26, 2015 at 113-114.
[30] New York Public Service Commission, Case 14-M-0101, Track 1 Order, February 26, 2015 at 115.
[31] Case 14-M-0101, Memorandum and Resolution on Demonstration Projects, issued December 12, 2014.
[32] The complete list is available at the following web address: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument
[33] New York Public Service Commission, Case 16-G-0058 et al., Order, December 16, 2016 at 134. Case filings available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-g-0059&submit=Search
[34] See New York Public Service Commission Case 17-G-0606, available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=54621
[35] Based on a discussion with Bryan Berry, Assistant Director at NYSERDA.
[36] Xcel Energy, *Annual Report to the Minnesota State Legislature*, February 15, 2017, at 3. See https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/Renewable%20Energy/Renewable%20Development%20Fund/2017%20RDF%20Annual%20Report.pdf
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[38] Xcel Energy, Docket E002/M-17-775 Petition Before the Minnesota Public Utilities Commission, 1 November 2017, at 3-7. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B40D77C5F-0000-C614-A997-18C8C3D839F9%7D&documentTitle=201711-137092-01
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[47] AER, Explanatory Statement – Draft Demand Management Innovation Allowance Mechanism, August 2017, at 10.

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[49] Energy Networks Australia (ENA), *Network Innovations Discussion Paper*, July 2017 at 10-11.
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[52] Ring-fencing Guideline, Electricity Distribution Version 2, Explanatory Statement, AER, October 2017, pp. 8-9 https://www.aer.gov.au/system/files/AER%20-%20Ring-fencing%20Guideline%20Version%202%20-%20Explanatory%20Statement%20-%20October%202017.pdf
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[54] Ontario's Long-Term Energy Plan, Delivering Fairness and Choice, at 18. See https://www.ontario.ca/document/2017-long-term-energy-plan
[55] Ontario Energy Board 2017-2020 Business Plan, at 3. See https://www.oeb.ca/oeb/_Documents/Corporate/OEB_Business_Plan_2017-2020.pdf
[56] Ontario's Long-Term Energy Plan, Delivering Fairness and Choice, at 74-75.
[57] Based on a discussion with Ceiran Bishop of the Ontario Energy Board.
[58] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 32.
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Appendix C6-2

HISTORY OF U.S. NATURAL GAS R&D, RON EDELSTEIN

History of U.S. Natural Gas R&D

Ron Edelstein

Executive Summary

The history of natural gas research and development in the United States is outlined, from 1925 to the present day. The origin of funding, the research organizations involved, the energy-related events taking place in the country at the time critical decisions were made on how best to purse R&D funding, and the various key players in the decision making process are delineated. The impact of the R&D on US gas consumers is discussed. Most notable were R&D contributions to the Shale Gas Revolution and to the development and commercialization of high-efficiency furnaces, boilers, and water heaters.

Background

Collaborative[1] natural gas (gas) research and development (R&D[2]) in the United States began with the formation of American Gas Association (A.G.A.) Labs in 1925. These labs, established in Cleveland and later in Los Angeles, developed technology to improve gas appliances and equipment, making them more energy efficient and consumer friendly. The labs also did testing to ensure gas equipment conformed to national standards for safety, durability, and performance. The A.G.A. ended its laboratory activities in 1997.

The Institute of Gas Technology (IGT) was founded in 1941 in Chicago. IGT supported the gas industry need to train graduate engineers. IGT was affiliated with the Illinois Institute of Technology (IIT) as a degree-granting institution from 1941 to 1994, when IGT moved off IIT's campus to larger facilities in Des Plaines, IL. Initial focus included research on coal gasification.

The Pipeline Research Council International, Inc. (PRCI) is a tax-exempt, not-for-profit corporation comprised primarily of energy pipeline companies. PRCI was established in 1952 as the Pipeline Research Committee of the A.G.A. and became an independent not-for-profit corporation in 2000. PRCI's initial charter was to confront the problem of long-running brittle fracture in natural gas transmission pipelines. PRCI's solution of that problem within two years demonstrated the impact and benefits of industry collaboration and the leveraging effect of voluntary funding. Although initially an organization focused solely on pipelines in North America, PRCI began to broaden its membership and technical perspectives beginning in 1980 with the membership of the Dutch pipeline operator, Gasunie.

A confluence of events in the 1960s and especially the 1970s led to the establishment of a number of energy R&D organizations.

In November 1965, the Great Northeastern Blackout left 30 million people in the United States without electricity, starkly demonstrating the nation's growing dependence on electricity and vulnerability to its loss. It was a watershed event for the industry and triggered the creation of the Electric Power Research Institute (EPRI). EPRI was established in 1972 by the electric utility industry to conduct research on issues related to their industry. EPRI is a nonprofit organization funded by the electric utility industry, headquartered in Palo Alto, California.

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[1] As opposed to proprietary R&D

[2] The terms "R&D" and "RD&D" are used interchangeably in this document; the technical difference being the demonstration phase of RD&D.

This focus on energy R&D was exacerbated by the Oil Embargo of 1973 and lines at gasoline stations across the U.S. Energy moved to the forefront of strategic concerns for the country. Collaborative R&D organizations were formed to address energy prices, shortages (perceived and real), and effective (i.e. more efficient) energy use.

On October 11, 1974 President Gerald R. Ford signed the Energy Reorganization Act of 1974. The act abolished the Atomic Energy Commission and created three new federal entities: the Energy Research and Development Administration (ERDA), the Nuclear Regulatory Commission (NRC), and an Energy Resources Council composed of the Secretaries of State and Interior, the administrators of ERDA and Federal Energy Administration (FEA) and the director of the Office of Management and Budget. The ERDA brought together the major programs of R&D for all forms of energy for the first time.

TO ERDA, the Atomic Energy Commission contributed personnel, budget, and programs concerned with nuclear reactors, fusion research, uranium enrichment, and basic scientific research, along with a vast network of offices, national laboratories, and nuclear weapons research and production facilities. A variety of energy programs from other federal agencies were folded into ERDA. From the Department of the Interior (DOI) came the Office of Coal Research and the non-regulatory functions of the Bureau of Mines, including the energy centers, the synthane plant, the coal liquefaction and gasification programs, and activities related to underground electric power transmission. The National Science Foundation (NSF) brought its solar heating and cooling and geothermal power development projects, while the Environmental Protection Agency (EPA) transferred its RD&D programs relating to advanced automotive propulsion. Although these diverse elements included some of the nation's finest talent in R&D, ERDA would take more than a year to meld them into a smoothly functioning agency. Six assistant administrators headed the major programs for fossil, nuclear, solar, geothermal and advanced energy systems, conservation, environment and safety, and national security. The fuel programs--fossil, nuclear, solar, and geothermal and advanced energy systems--received the major portion of the research budget, with lesser amounts allocated to energy conservation.[3]

The Department of Energy (DOE) Organization Act of 1977 created one of the most interesting and diverse agencies in the Federal government. Activated on October 1, 1977, the twelfth cabinet-level department brought together two programmatic traditions that had long coexisted within the Federal establishment: 1) defense responsibilities that included the design, construction, and testing of nuclear weapons dating from the Manhattan Project effort to build the atomic bomb, and 2) a loosely knit amalgamation of energy-related programs scattered throughout the Federal government.

The establishment of the DOE brought most Federal energy activities under one agency for the first time and provided the framework for a comprehensive and balanced national energy plan. The Department undertook responsibility for long-term, high-risk research and development of energy technology, Federal power marketing, energy conservation, the nuclear weapons program, energy regulatory programs, and a central energy data collection and analysis program. The DOE replaced ERDA as the center of Federal energy-related R&D.[4]

The Solar Energy Research Institute (SERI) was established by the Federal Government in 1974 in Golden, Colorado and began operations in 1977, to address R&D challenges related to renewable energy, including but not limited to solar, wind, biomass, and ocean thermal systems.

In 1976 and 1977, many schools and factories in the Midwest were forced to close, due to a shortage of natural gas to run their facilities. Meanwhile, in the producing states, virtually no shortage was felt, due to the thriving intrastate market satisfying natural gas demand in these states.

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[3] "A History of the Energy Research and Development Administration," Alice Buck, March 1982.

[4] https://www.energy.gov/management/office-management/operational-management/history/brief-history-department-energy

This led to certain ‘curtailment’ policies, advocated by the Federal Power Commission (FPC) and state utility regulators. These policies essentially set a schedule of priority, directing distributors and transporters to curtail supplies to certain customers who were deemed ‘low priority’. The perceived shortage of natural gas, and the actual shortage on the interstate market, led in part to the formation of the Gas Research Institute (GRI) in 1976.

Formation of GRI

The R&D programs conducted by individual local distribution companies (LDCs), A.G.A. Labs, and the Federal Government were not enough to address the increasingly complex problems faced by the gas industry. In 1973, when the gas industry needed to replenish the apparently rapidly dwindling supplies of natural gas from both conventional and novel sources, an ad hoc committee composed of A.G.A. and the Interstate Natural Gas Association of America (INGAA) Board members proposed the creation of a gas research organization whose greatly expanded, comprehensive R&D effort could ensure advancement of the current state of gas-related technology.[5]

In June 1976, the FPC, predecessor to the Federal Energy Regulatory Commission (FERC), issued a notice of proposed rulemaking, FPC 566, to “provide additional procedures and guidelines whereby requests for advance assurance of rate treatment for R&D expenditures may be used by jurisdictional [i.e., FPC-FERC jurisdictional interstate gas pipeline and electric transmission] companies to insure the support of well-planned and comprehensive R&D programs.[6] The FPC opened the rulemaking because “We have not yet seen the level of concentrated effort by the natural gas industry that public interest requires to significantly advance the state of technology to relieve the severe curtailment of service now being experienced by interstate natural gas pipeline companies.”

There were 45 intervenors that responded in support of the rule, including A.G.A., major gas LDCs, INGAA, interstate gas pipelines, the National Association of Regulatory Utility Commissioners (NARUC), universities, Edison Electric Institute (EEI), state Public Utility Commissions (PUCs), electric utilities, and research institutes.

Research, development and demonstration (RD&D) was defined[7] for GRI by the FPC. Jurisdictional companies were *not required* to join the program; it was to be voluntary for the jurisdictional companies. (In this case the jurisdictional companies were gas pipelines and electric transmission companies.) PUCs would be notified of the proceedings before the FPC/FERC for advance approval of the RD&D, and in this way the PUCs could determine their interest in the RD&D filings on a case-by-case basis. They would become automatic intervenors in any subsequent rate cases.

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[5] “1982-1986 Five Year R&D Plan and 1982 R&D Program”, GRI, 1981, p. 1.

[6] FPC Order Number 566, p. 1, 1977

[7] “RD&D means expenditures incurred by public utilities and licensees either directly or through another person or organization (such as research institute, industry association, foundation, university, engineering company, or similar contractor) in pursuing research, development, and demonstration activities including experiment, design, installation, construction, or operation. This definition includes expenditures for the implementation or development of new and/or existing concepts until technically feasible and commercially feasible operations are verified. Such RD&D costs should be reasonably related to the existing or future utility business, broadly defined, of a public utility or licensee or the environment in which it operates or intends to operate. The term includes, but is not limited to, the design, development, or implementation of an experimental facility, a plant process, a product, a formula, an invention, a system or similar items, and the improvement of already existing items of a like nature; amounts expended in connection with the proposed development of alternative sources of electricity; and the costs of obtaining its own patent.”

The FPC issued its decision, a positive one, in June 1977. Anticipating this, the A.G.A. and INGAA Boards approved the formation of GRI and endorsed the concept of a gas industry R&D organization. GRI was incorporated as a not-for-profit Illinois corporation in July 1976. Funding for the RD&D program would be provided by a surcharge on shipments of natural gas sold by the interstate pipelines. Gas LDC's would incorporate the R&D surcharge into rates to their customers by the "filed rate doctrine" without the need for prior PUC approval, as the surcharge was already approved by the FERC for interstate pipelines.

GRI's first RD&D plan was submitted in 1977, and a budget of $30.1 million was proposed, made up of both FPC and A.G.A. funding mechanisms. The first FERC-approved funds, totaling $9.5 million, were granted in 1978.

There were five principal tests for the adequacy of the RD&D program, established by the FPC and later reaffirmed by the FERC.[8] In order to meet them, GRI took the following steps:

- Established a hierarchy of objectives—from strategic ones like "enhancing natural gas supply from unconventional sources", to tactical objectives like "provide the information necessary for rational decision making concerning the shale resource base", to project objectives such as "develop qualitative and quantitative resource assessment of the value of shale gas potential by geographic areas." (Test 1)
- Established four Board-level advisory bodies (Tests 2 and 3):
    - Research Coordination Council (RCC), made up of representatives from universities, national laboratories, Federal R&D organizations like DOE, and international R&D groups to provide scientific review of the R&D program
    - The Advisory Council (AC), made up of PUC Commissioners, environmental groups, and other public interest advocates to ensure that the R&D was in the gas consumer and public interest
    - The Municipal Gas System Advisory Committee (MGSAC), made up of municipal utility representatives, to provide review by smaller municipally owned gas systems
    - The Industry Technical Advisory Committee (ITAC), made up of representatives from member gas pipelines, gas producers, and gas LDCs to provide strategic review of programs by the gas industry
    - Eight Project Advisor Groups (PAGs) to ensure detailed technical review by industry subject matter experts of all major subprograms[9]
- Development and use of the Project Appraisal Methodology (PAM), which provided a benefit/cost analysis of all applied RD&D projects to assess consumer benefits and RD&D

[8] "(1) Evidence that the RD&D objectives of the company or research organization have been clearly established; (2) Evidence that the plan evolves from these RD&D objectives and adequately utilizes the viewpoints of scientific, engineering, industry, economic, consumers and environmental interests; (3) Evidence that an effective mechanism exists and is used for coordinating this research and development plan with other relevant efforts of national scope; (4) Evidence that the project or program is well conceived and, if successful, has a reasonable chance of benefitting the ratepayer in a reasonable period of time, having due regard for the basic, exploratory, or applied nature of each submitted R&D project; and (5) Evidence that whatever achievements may result, including knowledge or technology developed from the RD&D program, will accrue to the benefit of the jurisdictional companies and their sponsors."

[9] PAGs included: Supply, Energy Economics, Transmission, Distribution, Residential/Commercial, Industrial, Environmental, and Basic Research.

multi-year costs, using such criteria as consumer (dollar) savings, energy saved, environmental benefits, consumer options enhanced, and O&M savings to the industry (Tests 4 and 5). Basic research and environmental projects were not subject to PAM.

In an era of gas curtailments and perceived shortages of natural gas, the initial focus of GRI's R&D program was principally on natural gas supply, including unconventional gas (tight sands, coalbed methane, and shale gas) and the development of synthetic or substitute natural gas, from coal or renewable resources. Conventional gas R&D was left to the major producers and the oilfield/gasfield service companies. In addition to the supply program, end-use R&D was conducted on energy efficiency improvements for the residential, commercial, and industrial markets. Power generation R&D was left to the electric industry and EPRI. Some R&D on operations technologies for gas transmission, storage, and distribution was also conducted.

The principal mission of GRI was "To achieve mutual benefits for the gas industry and gas consumers by planning, managing, and developing financing for an R&D program, subject to review and approval by the FERC and, where appropriate, state regulatory commissions."[10] This program was designed to meet the following objectives:

- Develop cost-competitive sources of gaseous fuels; highly efficient gas appliances, equipment, and industrial processes offering least-cost energy service options; and cost-effective means for safer and environmentally more benign production, transport, storage, and utilization of gaseous fuels
- Advance gas science and technology through long-range planning and basic research[11]
- Support these R&D activities with the development and analysis of technical, scientific, and economic data
- Facilitate the use of results of this program through vigorous information dissemination and technology application efforts.

GRI was designed to manage the research projects, *not* conduct the research itself. Instead GRI established broad objectives and technical goals, then contracted with research institutions, consulting firms, universities, energy companies, engineering firms, and manufacturers to conduct the gas-related R&D. Many of these projects were partially funded (or cofunded) in cash or in kind by the performer, government agencies or laboratories, manufacturers, oilfield services companies, producers, and gas LDCs and pipelines.

RD&D budgets grew to $100 million by 1982. As the interstate price of natural gas at the wellhead was decontrolled, more gas became available, so the RD&D focus shifted more toward end-use efforts. A first major success in 1983 was the development and commercialization of the Lennox Pulse furnace, the world's first (fully condensing) residential furnace with higher than 90% efficiency. Transmission and distribution R&D also grew, with focus on safety and reduction of operating and maintenance (O&M) costs for pipelines, LDCs, and municipal gas companies.

GRI's R&D program budget topped out at $212 million per year in 1992, with a surcharge of about 1.75 cents per MMBtu collected on ~10-12 Tcf of interstate gas, plus some voluntary intrastate gas in Texas and Louisiana.

[10] "GRI 1983-1987 RD&D Plan and 1983 R&D Program," April 2, 1982, p.1

[11] 10-15% of GRI's budget was dedicated to basic research, mainly conducted at universities.

Program Emphasis[12]

GRI had four overall objectives (programs), Supply Options, End Use, Gas Operations, and Crosscutting Research. ITAC and the GRI Board provided strategic input on what the budget percentages should be between overall objectives.

With real and perceived shortages and gas curtailments of the 1970s, the Supply Options program was 57% of the total GRI budget in 1979. This was reduced to 45% in 1981, and reached a low of 25.7% in 1988. By 1995, the Supply Options budget had gone back up over 30%, and remained at about one-third of GTI's budget thereafter.

End Use R&D was 27.3% of GRI's budget in 1979, growing to 53.7% by 1983, and subsequently remaining at about half of GRI's budget.

Gas Operations (T&D) R&D was smaller, starting at 4.7% in 1979, but growing to 8.7% by 1982. By 1994, it was 19.6% of GRI's budget, and remained in the 20% range.

In the 1989 "A Review of the Management of the Gas Research Institute", the Energy Engineering Board stated that "Based on its review to date of the [GRI] portfolio and this overview of the planning process, the Committee finds no reason to doubt the integrity of the process used by GRI to develop its portfolio."[13]

Supply and Unconventional Gas R&D

Originally, the Supply budget at GRI was divided between unconventional gas and substitute natural gas (SNG) R&D. SNG included coal gasification, both in situ (underground in formations) and above ground, as well as biomass gasification. For instance in 1986, 33.6% of the Supply budget was dedicated to SNG R&D. By 1991, the SNG budget percentage had dwindled to less than 1% of Supply.[14] The shifting focus was due to the increasing supply of natural gas from conventional and unconventional wells (due to R&D successes on unconventional gas, wellhead price decontrols, the investment tax credit, and higher gas prices) and the reduced need seen for higher-cost SNG.

GRI's biggest success was in unconventional gas R&D. As seen from Figure 1, when GRI started this R&D in the late 1970's unconventional gas was less than 50 billion cubic feet (Bcf/year). Tight sands R&D was the first success, down in Texas and out in the Rockies. Coalbed methane was next, starting in the Black Warrior Basin of Alabama, then moving to Texas and the Rockies. By 2016, 15.8 Tcf of natural gas was produced from shale gas and oil wells (not including coalbed methane or tight sands production), 48.4% of total U.S. production, according to EIA.

[12] "A Review of the Management of the Gas Research Institute", Energy Engineering Board, National Research Council, 1989, p. A-19.
[13] EEB NRC, p. A-20.
[14] "1991-9995 R&D Plan and 1991 R&D Program", GRI, 1989, p. 32.

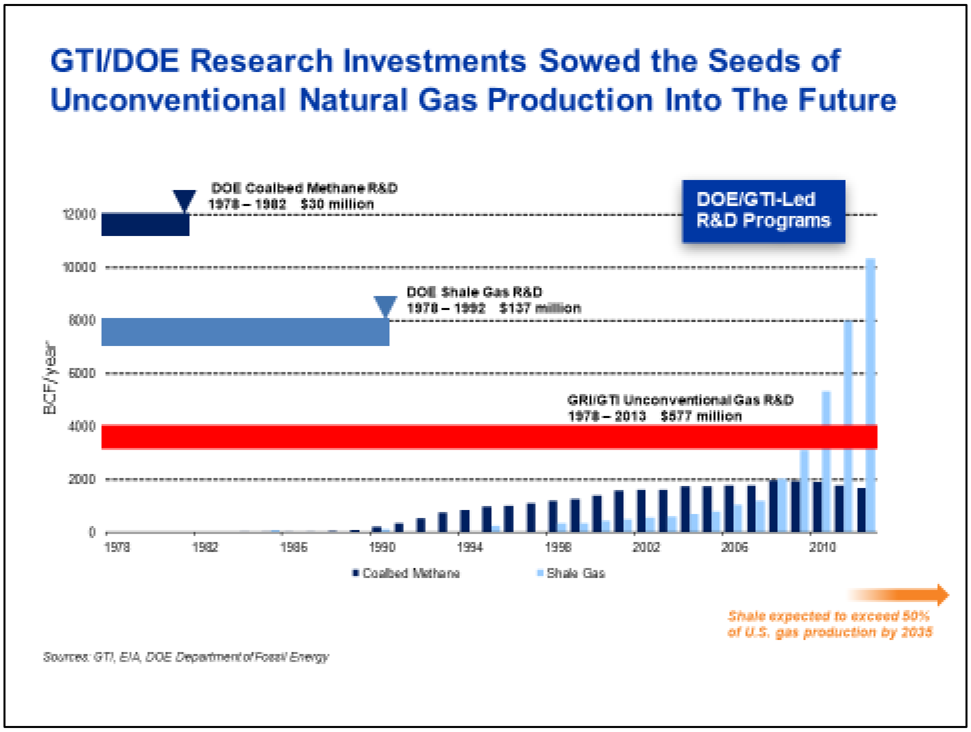


Figure 1. Shale Gas R&D Expenditure and Production

The Shale gas revolution did not happen overnight. It took 30 years of R&D to develop the technologies that lead to this breakthrough. Three different advanced technologies were involved: 3D seismic to locate the shale zones, hydraulic fracturing to increase the permeability of the formations, and horizontal drilling to enable horizontal wells to follow the shale gas formation. Private ownership of property rights in the U.S. helped to make shale development successful, encouraging mineral rights owners to agree to allow development of resources under their properties, Innovative producers like George Mitchell, who were willing to take a risk by pioneering new drilling and completion technologies that led to breakthroughs, were also tremendously helpful.

Coalbed methane has topped at over 2,000 Bcf/yr, and shale gas is already almost half of U.S. production, as indicated. Would this have happened without industry managed R&D? Maybe so, but much later in time, maybe decades later. A 100-year technically recoverable supply of natural gas is now estimated for North America. Benefits to U.S. gas consumers from unconventional gas R&D of over $50 billion per year[15] are estimated just from residential, commercial, and industrial customers, not including the use of natural gas for power generation. While GTI spent almost $600 million on unconventional gas R&D, as indicated in Figure 1, and DOE almost $200 million, the benefit/cost ratio for gas consumers is quite significant.

End-Use R&D: Successes and Challenges

With the success of the high-efficiency furnace, GRI shifted to other areas. Major breakthroughs in gas water heating, commercial cooking equipment, industrial process heat, blast furnace gas injection, natural gas vehicles (NGVs), and combined heat and power (CHP) have occurred. Gas

[15] "Missouri Natural Gas Customer R&D Needs," Presentation before the Missouri Public Service Commission, January 2017, R. Edelstein, slide 4.

cooling has taken longer. A gas heat pump has now reached the U.S. market, the NextAire IntelliChoice engine-driven unit made by Aisin, supported by DOE, SW Gas, and GTI R&D. Absorption-based GHPs (with equivalent heating efficiencies of 160%) and GHP water heaters (with equivalent efficiencies of 138%) are still under development, supported by DOE and GTI. Further first-cost reduction and efficiency increases are major challenges remaining for GHPs and GHP water heaters.

Some intervenors objected to R&D for NGVs, cofiring of gas and coal in power plants, and other projects as "load building," not appropriate for ratepayer-based funding. In January 1989, the U.S. Court of Appeals for the District of Columbia in Process Gas Consumers v. FERC, affirmed that end-use R&D is appropriately within FERC's jurisdiction, and that current ratepayers can be charged for benefitting future gas users in existing customer classes. FERC then asked GRI to provide an analysis and justification of its end-use program with regard to four issues: (1) the likely benefits of successful research to ratepayers, (2) the potential of end-use R&D to result in new demand and the accompanying impact on wellhead gas prices, (3) the potential for increased demand of natural gas to adversely affect cross-elasticity of demand, and (4) the impact of other factors, such as savings in per-unit transmission and distribution (T&D) costs and environmental compliance costs to ameliorate any increases in gas prices caused by increased demand.[16] So GRI instituted and conducted a "net benefits test" for all applied R&D end-use projects that subtracted from the benefits of the technologies the theoretical demand-induced price increases. The end-use R&D was divided into three classes: (1) existing customer classes, existing applications, (2) existing customer classes, new applications, and (3) new customer classes, new applications. Residential/commercial space and water heating and commercial/industrial boilers were examples of Class 1 applications. Gas cooling was an example of a Class 2 application. NGVs and coal-gas cofiring (in power plants) were an example of a Class 3 application. Class 2 and 3 technologies were subject to the net benefits test.

Gas Operations R&D

GRI performed extensive research on plastic distribution pipe, looking for ways to prevent slow crack growth and rapid crack propagation. An accelerated lifetime test was developed for plastic pipe to estimate its life expectancy.

One major challenge for the gas LDCs was locating buried plastic pipe. Plastic pipe does not give out any signals. It is inert, nonmagnetic, and virtually undetectable if and when the tracer wire placed above it becomes nonfunctional. Due to the difficulty of detection, it took 30 years' worth of R&D and multiple technical pathways to develop a successful acoustic-based plastic pipe locator that is now commercially available from Sensit Technologies. R&D pathways included underground radar, acoustic approaches, and magnetic particle infused plastic pipe.

With the focus on preventing failures of gas pipeline and distribution systems, the development of enhanced sensors to use in-line inspection (pigging) to detect wall thinning, improper welding, stress corrosion cracking, coating disbonding, and other defects and anomalies continues.

Guidelines to prevent microbially induced corrosion (MIC) in pipelines, responsible for a significant portion of pipeline corrosion, have been developed and publicly released.

[16] "1990-1994 R&D Plan and 1990 R&D Program, GRI, 1989, p. xi

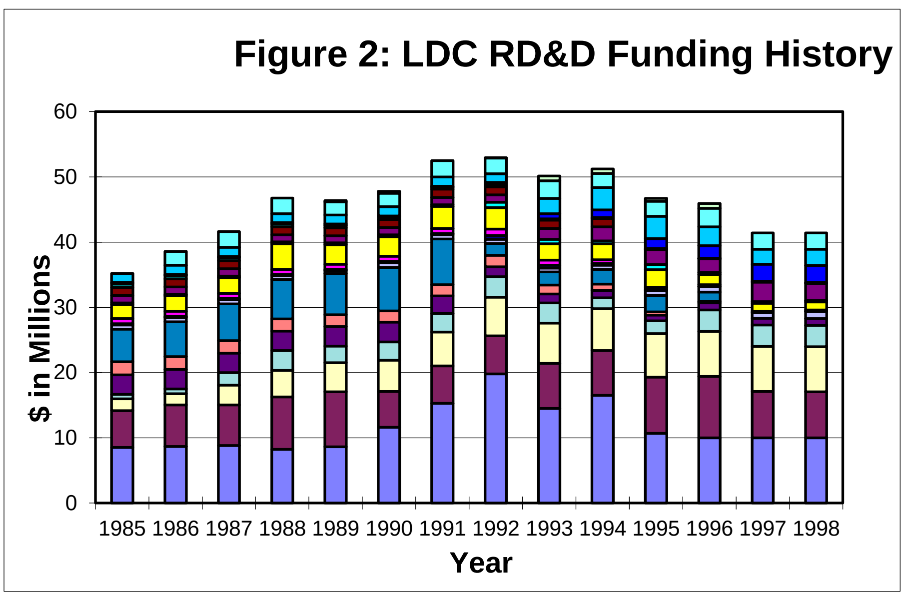
Methods to reduce third-party damage, the primary cause of distribution pipe system failure, continue to be investigated, including providing equipment operators with an early warning of proximity to gas mains and services and notification to gas LDCs of encroachment. Guidelines and an outreach program are raising awareness and streamlining the implementation of best practices to prevent cross boring of sewer lines and gas lines.

Close coordination with PRCI and the Pipeline and Hazardous Materials Administration (PHMSA) is a necessity for transmission-related R&D, and joint cofunded projects have been conducted, where appropriate. Advances have been made in maximum allowable operating pressure (MAOP) verification and yield strength determination via small samples for pipeline integrity verification. Work continues on failure prediction and risk assessment models for pipelines, and more advanced sensors for pipeline inline inspection.

Non-FERC Natural Gas R&D and Gas-Related R&D Funding History

During the period of GRI funding, other sources of gas-related R&D funding were available. Aside from proprietary efforts by the major producers and gas field service companies, gas LDCs funded some $25-$50 million per year in internal R&D. Major companies, like Brooklyn Union Gas, Southern California Gas Company, Pacific Gas & Electric, Atlanta Gas Light, and Columbia Gas had internal R&D programs that cofunded GRI research efforts, They also conducted R&D on their own or through organizations such as NYGAS/NYSEARCH (for distribution and some end-use) in New York, or PRCI (for pipeline and storage-related projects).

Figure 2 shows a profile of early gas LDC R&D, 1985-1998, not including FERC-approved funding.[17] As illustrated, gas LDC R&D peaked at about $53 million in 1992, and declined thereafter. While NYSEARCH and PRCI funding continues, currently almost all U.S. gas LDCs have closed down their internal R&D programs. The notable exception is Southern California Gas Company, which still maintains a robust internal R&D program at about $10-$12 million per year.

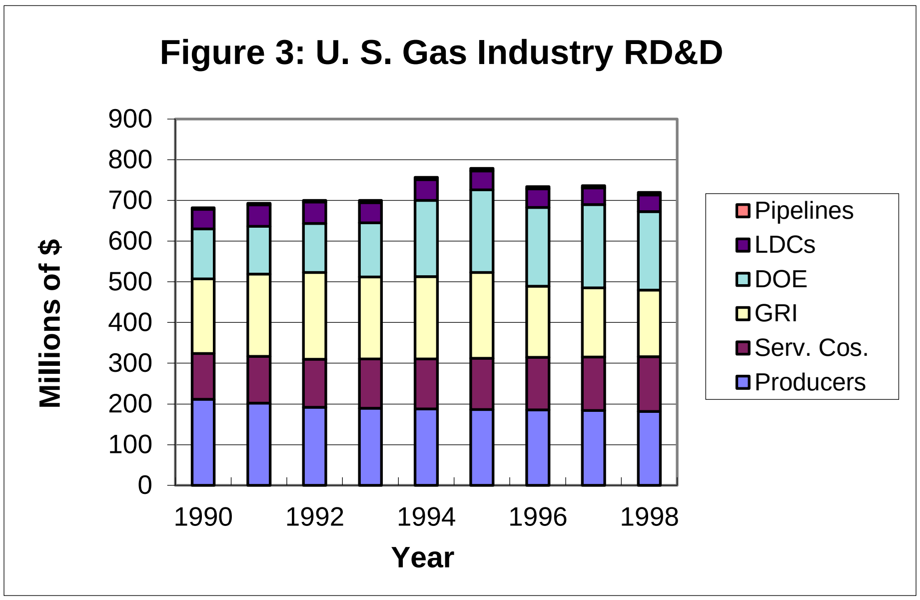


[17] While individual company funding is shown, companies are not identified as some of the information is proprietary. Tracking of these data ended in 1998.

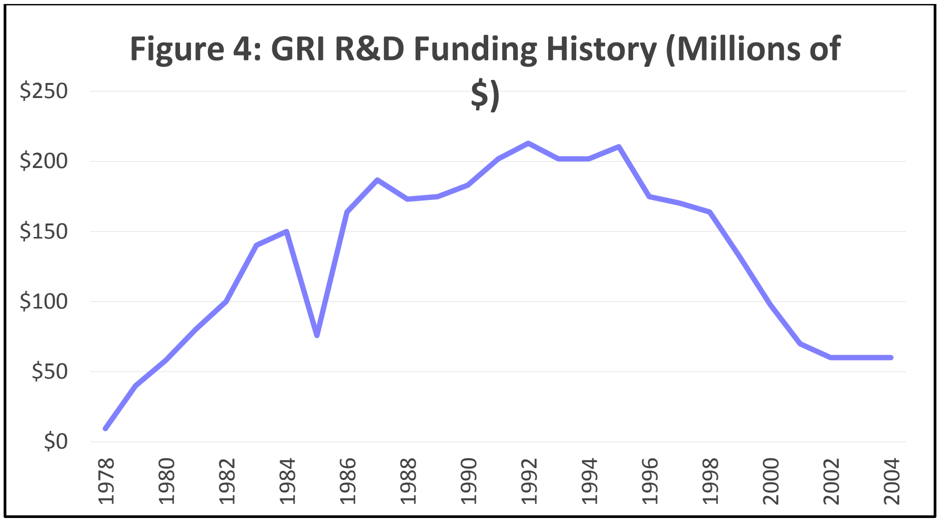
DOE also had an extensive gas-related R&D program focused on end-use efficiency of gas space and water heating, cooling, CHP and distributed generation, industrial processes, NGVs, and fuel cells. During its peak,

Total gas-related R&D is shown in Figure 3, including GRI, DOE, producers, service companies, pipelines, and gas LDCs. It peaked at about $780 million per year in 1995. DOE gas-related R&D funding peaked at about $203 million in 1995. Today, that R&D continues, though at a severely reduced level, probably around $50 million per year in DOE Fossil and Energy Efficiency and Renewable Energy (EERE) Programs

Figure 4 shows a history of GRI R&D, from its inception until 2004, the end of FERC-approved R&D funding. As already noted, GRI R&D peaked at $212 million in 1992.[18] Total expenditures were about $3.5 billion over 40 years. Gas consumer benefits over the same period, were 4/1 to 9/1 compared to R&D costs and these benefits, discussed below, for shale gas R&D and the high-efficiency furnaces, water heater, boilers, and other end-use equipment, continue today.[19]



[18] Tracking of DOE gas-related R&D funding was done by an A.G.A. R&D Committee. This tracking ended in 1998.
[19] See, for example, "Benefits of GRI R&D Results that have been Placed in Commercial Use in 1997 through 2001," Antanasios Bournakis, University of Illinois at Chicago, May 2002



Breaking of the Compact

In 1985, FERC Order No. 436 required that natural gas pipelines provide open access to transportation services, enabling consumers to negotiate prices directly with producers and contract separately for transportation. In 1990, natural gas futures trading began on the NYMEX.

Historically, interstate gas pipelines acted as both a transporter of natural gas, as well as a seller of the commodity, both of which were rolled up into a bundled product and sold for one price. However, since April 1992, with FERC Order 636, interstate pipelines are no longer permitted to act as merchants and sell bundled products. Instead, they could only sell the transportation component, and never take ownership of the natural gas themselves. Pipelines were also required to offer access to their transportation infrastructure to all other market players equally, referred to as "open accesses" to the pipelines. This allowed marketers, producers, LDCs, and even end users themselves to contract for transportation of their natural gas via interstate pipeline, on an equal and unbiased basis.

Since large customers could demand a discount below the price ceiling established by FERC, pipelines selling discounted gas asserted that they (as opposed to gas consumers) were paying a portion or all of the GRI surcharge. Faced with this situation, two pipelines resigned from GRI effective January 1, 1993[20], and many others threatened to follow suit.

Faced with the prospect of massive member resignations, GRI proposed a modification of its funding mechanism for 1993. The proposal recommended collecting most of GRI's funding through the established volumetric surcharge. However, pipelines who sold discounted gas would be able to avoid part or all of the GRI surcharge, depending upon the amount of discount. In other words, on discounted transactions, pipelines would remit to GRI only the amount by which the price actually charged to the customer exceeded the non-discounted price of the gas (excluding the surcharge), up to the amount of the GRI surcharge. The Interim Funding Order not only approved the GRI funding mechanism for 1993, but also directed that a settlement conference be convened under the auspices of an administrative law judge (ALJ) to develop a more permanent system of GRI funding.

[20] see ANR Pipeline Co., 58 F.E.R.C. at 61,723 & n.10

So, in addition to large industrial customers' opposition to "new load" end use R&D (see the previous discussion on PGC v FERC), natural gas pipelines were now also expressing concerns about the R&D surcharge. Since they were the ones collecting the surcharge and writing the check to GTI, they felt the money was coming out of their own pockets. Further, some producers were worried about "netback pricing"[21] forcing them to fund the surcharge. Gas LDCs felt they had absorbed some of the R&D costs as well, especially between rate cases.

In November 1997, in its decision[22] approving GRI's 1998 R&D program, the Commission appointed an ALJ to convene Settlement Conferences involving all interested parties to arrive at a broadly supported consensus on funding issues. In January 1998, a Stipulation and Agreement was reached[23]. The Agreement called for funding of GRI through the FERC funding mechanism until the end of 2003, or 2004 if additional (true up) funds were needed to close out the program. During that time, a voluntary funding method, not dependent on a FERC surcharge, was to be developed by GRI or a subsequent organization to support the R&D program. After January 1, 2005, all GRI funding was to be on a voluntary basis (independent of FERC approval). Individual pipelines could still apply for R&D funding for selected projects.

The Commission talked specifically about a "check the box" method whereby shippers (e.g., gas LDCs) could voluntarily elect to have pipelines collect R&D funds for them, without the pipelines seeking FERC approval of the R&D. Presumably, the gas LDCs would need to go to their regulatory bodies (i.e., their PUCs) to gain approval.

As part of the Settlement, Core Program R&D areas were agreed to by all parties. These included:

- Enhanced Environmental Quality
- Lowered Operating and Maintenance Cost
- Enhanced Health & Safety
- Improved Gas System Integrity and Reliability
- Increased Efficiency of Use
- Increased Gas Supply from Emerging Resources.

Notably absent from this list were the "non-core" consumer options with an emphasis on load-building, like NGVs or cofiring of gas and coal in power plants.

And thus the FERC-approved GRI R&D program, in place since 1977, was brought to an orderly close. Budgets were reduced year-by-year, from $164 million in 1998, down to $60 million in 2003 and 2004 to zero in 2005 (see Figure 4).

Early Post-Settlement Activities to Fund Gas R&D

As the FERC funding mechanism wound down, the GRI Board looked for alternative funding approaches. Acquisition by another company or merger was one option. While many companies were reviewed as possible partners, the GRI Board, in concurrence with the IGT Board, agreed that

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[21] Netback pricing is the total cost that is connected to bringing natural gas to the marketplace and the revenues from all the products that are generated from it, and so it would not include the GRI surcharge.
[22] FERC Opinion Number 418, 1997
[23] FERC Docket RP-97-391-000 Stipulation & Agreement, January 1998

the two major research and technology development organizations serving the natural gas LDCs should combine into one. The merger took place in 2000.

Prior to the merger, GRI had been an R&D program management organization, like DOE, the New York State Energy Research and Development Authority (NYSERDA), or EPRI. After the merger, it was decided by the new Board that the new entity, now called Gas Technology Institute (GTI), would become a performing laboratory, like IGT was. This was a major shift in direction from GRI's program management role, and was not achieved overnight. However, GTI has now successfully developed 28 fully functioning R&D labs, primarily at its current headquarter offices (formerly IGT offices and labs) in Des Plaines, Illinois.[24] Other labs have been acquired or built more recently in other locations across the nation through acquisitions and DOE contracts. GTI was established as a not-for-profit 501(c)(3) corporation, as were GRI and IGT.

While FERC funding continued through 2003 and into 2004, a permanent "voluntary funding" mechanism was needed to support the new organization. Beginning in 1998, first GRI and then GTI sought funding from new sources. The California Energy Commission (CEC) and NYSERDA were approached for funding, as were Illinois sources, based on GTI's location.

The CEC, per AB 1890, had just received responsibility for a public interest R&D program of about $62.5 million per year from California electric ratepayers. GRI—and then GTI—participated in the California RD&D working group that helped build a strategic plan for what became, per SB90, the Public Interest Energy Research (PIER) Program. GRI—and then GTI—were able to bid competitively for financial support from the CEC, including PIER and other funding. GTI also bid on NYSERDA and Illinois Department of Commerce and Community Affairs (DCCA, later DCEO) funding.

However, a search for a way to garner funding from gas utilities continued. EPRI, since 1973, had been using a PUC-approved funding approach in the various states where electric LDCs were located. GTI decided to try that approach as well.

Starting in 1998, efforts got underway to find an approach to shift the difference (or Delta) between the declining FERC funding from the purchased gas adjustment (PGA) where most FERC surcharges lay, to base rates for gas LDCs. This was called the Delta Program, and was received with some favor, as it would not result in a rate increase, but simply shift the FERC surcharge to PUC-approved base rates.

By 2000, a number of companies had voluntarily applied for funding, and states had approved this shifting of funding from the PGA to base rates or funding the R&D directly within the PGA. These companies included Questar Gas in UT and WY, Alabama Gas, InterMountain Gas in ID, Atmos Energy in MS and KY, Northwest Natural Gas in WA, and some municipal gas companies.

Additionally, a major breakthrough occurred in New York in October 1998, when NYGAS supported a generic proceeding, eventually named the Millennium Program.[25] The NY Public Service Commission (PSC) issued a positive decision in January 2000, allowing funding of distribution-

[24] These labs include a Residential/Commercial End Use Lab, an Industrial End Use Lab, a Fuel Cell Lab, a Corrosion Lab, a Biological Lab, a FlexFuel Gasification Facility, an NGV Lab, a Plastic Pipe Lab, a Metal Pipe Lab, a Solar/CHP Lab, a Pipe "farm", a Distribution Equipment Test Lab, and, more recently, a Liquefaction Lab. Located in Texas, GTI also has in the Permian Basin a Hydraulic Fracture Test Site (HFTS), a kitchen test lab in California, and others.

[25] NY PSC Case 99-G-1369

related R&D, but indicating that end-use R&D would be considered on a case-by-case basis. The NY PSC approved the creation of an alternative funding mechanism to replace the existing funding and R&D by GRI. NYGAS called it “a voluntary state funding mechanism.” The jurisdictional companies included Brooklyn Union Gas (subsequently KeySpan, then National Grid), Consolidated Edison, Orange & Rockland, National Fuel Gas Distribution Company, Central Hudson Electric & Gas (E&G), New York State E&G, and Rochester G&E.

So, by early 2000, GRI had a voluntary funding mechanism established in eight states, mostly through movement of FERC-related PGA funds into base rates, with the notable exception of New York, where a generic proceeding achieved the same result. Approximately $5 million per year was collected by these companies, much of it going to GRI/GTI, but also funding NYGAS/NYSEARCH, some local universities, and other R&D entities.

Early 2000’s Efforts

From 1998 to 2002, gas-related, non-FERC R&D at GRI was conducted on a project-by-project basis, called GRI/GTI Select, with individual contracts negotiated by each participating party for each project. If multiple gas LDCs and multiple projects were involved, the negotiations could be lengthy.

In 2003, a major streamlining of collaborate R&D funding occurred. Operations Technology Development (OTD) was formed as a not-for-profit 501(c)(6) industry-led consortium. The OTD Board decided that GTI should manage OTD. Standard terms and conditions were developed and signed by all members. This led to a substantial reduction in negotiating time between OTD members themselves, and between them and GTI. Their number of customers, at 50 cents per customer, determines the funding level for each member, subject to PUC approval. The maximum annual cost is $750,000 per company, even for multistate companies.

Aside from a management fee (7.5%), zero funds are to be spent on R&D projects until the individual companies select the project(s) they wish to fund. This customer choice R&D program is very different than the GRI FERC-approved funding, where Board-level advisory bodies and technical PAGs debated the program balance between overall objectives and which projects to fund.

In the GRI program, a gas LDC participant that didn’t have any cast iron pipe might agree to fund cast iron replacement and repair R&D for “the good of the industry.” Under OTD’s flexible approach, if the LDC doesn’t have cast iron pipe, they could and would elect to not fund any cast iron R&D. Many gas LDCs appreciate this more customized approach.

With technical issues that span the country, and similar materials and technologies used in many gas systems, collaborative funding works really well. If just one company has a specific technical problem, obtaining full project funding might be more difficult, but the company could enlist other OTD members for support, ask GTI to look for cofunding from other sponsors such as PHMSA or NYSEARCH outside of OTD, or elect to fund the entire project on their own.

There are two primary gas industry committees within OTD. A Board-level committee made up of member company senior executives provides strategic direction and defines broad areas of gas industry concern. The Technical Project Committee (TPC) is composed of gas industry subject matter experts who define specific issues they would like OTD to perform R&D on, make the individual project selections, and allocate funding. In addition, there are ad hoc committees for each individual project, comprised of the TPC members (or their representatives) that are funding the effort.

GTI develops the research proposals. A stage-gate milestone process is used, so each proposal defines the R&D stage(s) to be funded. Rarely is full funding provided for a project all at once, so that progress and a go/no go decision can be reached by participants at each gate, or milestone. Funding decisions occur in real time at TPC meetings, since members receive the proposals in advance so that they can consult with others in their companies.

Because of the streamlined terms and conditions, the TPC member has the ability to actually authorize funds to be spent on individual projects, without having to talk to their company's legal staff. This speeds up the funding decision considerably and accelerates the project start date if members reach a decision to proceed and adequate funding for the project (and R&D stage) is allocated by OTD members.

Another unique feature of OTD is that royalties accrue to all OTD member companies in proportion to their funding, rather than to GTI. (If the background R&D was performed by GTI prior to OTD funding, then the royalty distribution would be proportionate to funding.) Royalties are put in the company hold account, to be later allocated by the company for further R&D, not returned to company ratepayers or shareholders.

OTD projects are divided up amongst program areas[26], but allocations are made on an individual project basis by each company. OTD members as of 2017 are shown in Figure 5.

Figure 5. OTD Members

In 2004, Utilization Technology Development (UTD) was established by gas LDCs to fund end-use efficiency R&D. Also an industry-led consortia, UTD operates on a similar basis, with both Board and TPC members, a customer choice project selection process, funding rates of 50 cents (initially

[26] Pipe & Leak Location, Pipe Materials Repair and Rehabilitation, Excavation & Site Restoration, Pipeline Integrity management and Automation, Operations Infrastructure Support, and Environmental Science & Forensic Chemistry

established at 40 cents) per each member company customer, and similar but not identical royalty arrangements. UTD funding maxes out at $350,000 per company, even for multistate companies.

UTD members as of 2017 are shown in Figure 6.

Figure 6. UTD Members

For OTD, all OTD members in good standing receive royalties; however, for UTD, the royalties are shared with only the direct funders of a project.

The sustaining Membership Program (SMP), a collaborative research program established by IGT, has been continued at GTI to focus on gas-related operations, environmental, or end-use early stage R&D. These projects, upon successful completion, can be funneled into OTD or UTD. Royalties for SMP belong to GTI. SMP funding also comes from ratepayers, but companies can elect to fund SMP directly or through their OTD and/or UTD dues. Efforts are underway to make this contribution from OTD and UTD more automatic. Funding is based on company (non-gas) revenues, but tops out for large companies at $100,000 per year. Project selection is similar to the old GRI approach, with the SMP Technical Guidance Committee choosing projects with an industry perspective rather than customer choice.

OTD annual funding = $10-15 million per year

UTD annual funding = $3-$4 million per year

SMP funding (not independent of OTD or UTD) = ~$2 million per year

These programs are all voluntary, as envisioned by the FERC. LDCs can drop out of the program at any time, and one or two have. But the vast majority of companies have been satisfied and stayed with the program, and have even sought funding via other states (see next section).

All FERC funding efforts came to a close in 2005, with funding ceasing by the end of 2004. All of GRI’s advisory bodies (AC, RCC, MGSAC, ITAC, and the PAGs) were disbanded before the end of

2000. GTI reestablished in 2000 a Board-level NARUC-appointed committee, the Public Interest Advisory Committee (PIAC), discussed in the next section.

Supply R&D is no longer funded by gas ratepayers. For a time, it was funded by a competitive bidding process under the Research Partnership for Sustainable Energy for America (RPSEA), using royalty trust funds from drilling on Federal lands, but that program ended in 2015. GTI's HFTS in the Permian Basin is a public-private collaboration funded by DOE's Office of Fossil Energy based on a competitive solicitation, and cofunded by producers and service companies.

Ironically, pipelines can still use the original FERC funding mechanism, via FPC 566, to fund transmission-related R&D. Pipeline companies fund most of their R&D through PRCI, and occasionally PRCI contracts projects through GTI labs. Some transmission-related projects are funded by LDCs through OTD, as many have higher-pressure transmission lines in their service territories. Many transmission-related projects are cofunding by PHMSA.

GTI tried to extend the FERC surcharge mechanism with a 2004 proposal to the FERC, but FERC would not accept it as they felt GRI and its successors were bound by the Stipulation and Agreement.[27]

Late 2000-2017 Efforts

As regulatory relations at GTI evolved, strategic changes were made in the approach to developing voluntary funding.

As mentioned above, GTI established a Board-level committee, PIAC, to replace the GRI AC. The purpose of the PIAC is to provide guidance to the GTI Board, executives, and senior staff on public interest issues and long-term trends that may potentially have impact on GTI, the gas industry, and consumers.

Per NARUC Charter, NARUC's President appoints Commissioner members from the NARUC Gas and Energy Resources and Environment (ERE) Committees. In addition, membership categories were created on PIAC for environmental representatives, economists, state and federal R&D program representatives, municipal utilities, academic/technical representatives, and consumer advocates (to be appointed by the National Association of State Utility Consumer Advocates [NASUCA]). Table 1 provides a list of current PIAC members. PIAC has been providing critical public sector (including PUC) input to GTI since 2000.

Table 1. GTI PIAC Members

Public Utility Commissioner Membership

The Honorable Bob Anthony, Chairman, Oklahoma Corporation Commission
The Honorable Kara Brighton, Commissioner, Wyoming Public Service Commission
The Honorable Julie Brown, Chairman, Florida Public Service Commission
The Honorable Diane Burman, Commissioner, New York Public Service Commission
The Honorable John Coleman, Jr., Commissioner, Pennsylvania Public Utility Commission
The Honorable Lamar Davis, Commissioner, Arkansas Public Service Commission
The Honorable Sherina Maye Edwards, Commissioner, Illinois Commerce Commission
The Honorable Julie Fedorchak, Chairman, North Dakota Public Service Commission
The Honorable Kristie Fiegen, Vice Chairman, South Dakota Public Utilities Commission

[27] FERC, Docket Number RP04-378-000, 2004

The Honorable Jim Huston, Commissioner, Indiana Utility Regulatory Commission
The Honorable Swain Whitfield, Vice Chairman, Public Service Commission of South Carolina
Consumer Advocate Membership
Dr. Belinda J. Kolb, Senior Rate Analyst, Office of Consumer Advocate, State of Wyoming
Economist Membership
Dr. Theodore R. Eck, Energy Economics Consultant
Academic/Technical Membership
Dr. Carl Blumstein, Director, California Institute for Energy and Environment
Mr. Gerald Braun, Director, Integrated Resources Network
Mr. Randy Knepper, Director of Safety, New Hampshire Public Utilities Commission (NAPSR rep.)
Mr. Steven Nadel, Executive Director, American Council for an Energy-Efficient Economy (ACEEE)
Federal/State R&D Agency Membership
Mr. Joseph Borowiec, Program Manager, Buildings R&D, New York State Energy Research and Development Authority (NYSERDA)
Mr. Christopher Freitas, Program Manager, Natural Gas R&D, U.S. Department of Energy
Environmental Membership
Mr. Howard A. Learner, Executive Director, Environmental Law and Policy Center
Ms. Elizabeth Noll, Legislative Director, Energy & Transportation Program, Natural Resources Defense Council
Municipal Membership
Mr. Wade Stinson, Associate General Manager - Operations, City Utilities of Springfield/American Public Gas Association Research Foundation (APGARF)
Mr. Charles S. Warrington, Jr., Managing Director & Executive Officer, Clearwater Gas System /APGARF

GTI actively supports gas LDCs in rate cases that proposed to include an R&D surcharge. This was a major change in direction, as neither GRI nor EPRI had actively participated in individual rate cases in individual states. GTI provides, if needed, an expert witness, detailed descriptions of proposed R&D projects, answers to discovery questions on the R&D program, and other support, such as a benefit/cost analysis. A list of states and company filings for voluntary recovery of R&D funds is shown in Table 2.

GTI continues the GRI practice of actively participating in regional and national NARUC meetings, through the NARUC Gas and ERE Committees or at general sessions. GTI committed to presenting to the Committees 2-3 times per year, as invited.

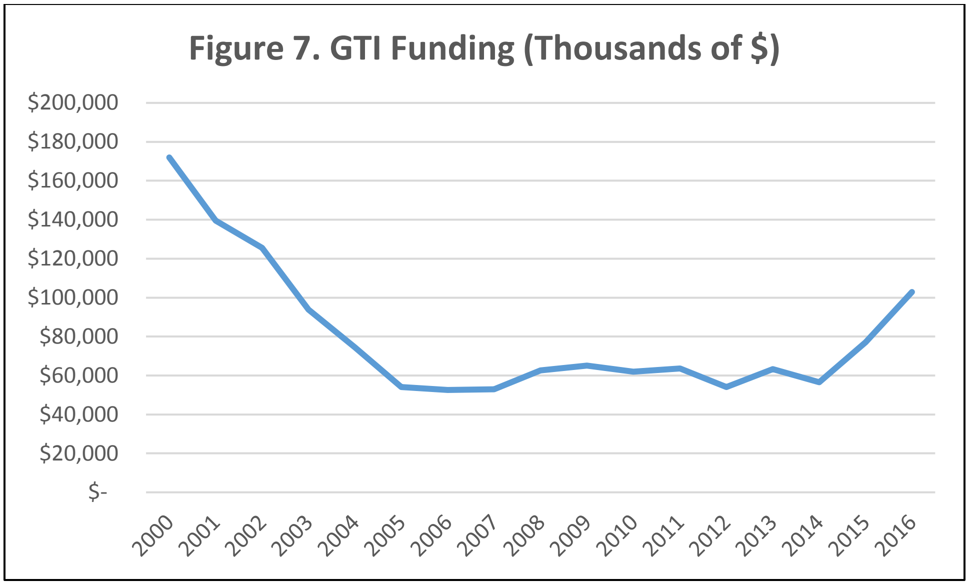
Table 2: Lists of States and Gas LDCs that have Approved Voluntary R&D Funding

Alabama: Alabama Gas - done through a purchased gas adjustment (GSA), (1998, docket no. not known)
Arizona: SW Gas (docket no. G-0115 1A-04-0876)
California: SoCal Gas and SDG&E (10-12-005 and 10-12-006), PG&E (2014, docket no. not known)
Colorado: Xcel Energy (2016, docket no. not known)
Delaware: Conectiv (2003, docket no. not known)
Florida: TECO (Docket No. 020384-GU, Order No. PSC-03-0038-FOF-GU and Docket No. 000003-GU)
Idaho: Avista and Intermountain Gas (Case No. INT-G-99-1 and Case No. AVU-G-99-2 Order No. 28189, respectively)
Illinois: Nicor (Docket # 04-0779), Atmos Energy (Docket No. 00-0228), Ameren (2015, docket no. not known)
Kentucky: West Kentucky Gas (Atmos Energy, KPSC Case No. 99-070), Columbia Gas of Kentucky (NiSource, Case No. 2002-00145), Delta Natural Gas (2004, docket number not known)
Louisiana: CenterPoint, Entergy, Atmos Energy, (Docket No. R-30479), generic proceeding

Maryland: WGL (Case No. 9322)
Minnesota: CenterPoint Minnegasco (Docket No. G008/GR-04-901)
Mississippi: Mississippi Valley Gas (Atmos Energy, MVG Co. Utility I.D. No. 123-0081-00)
Nevada: Southwest Gas (2010, docket no. not known)
New Hampshire: NiSource (Docket No. DG-01-182)
New Jersey: Public Service Electric & Gas (B.P.U.N.J. No. 13 Gas)
New Mexico: PNM (2005, docket number not known)
New York: Generic proceeding (Case No. 99-G-1369) with National Grid, New York State Electric & Gas, Consolidated Edison, Orange & Rockland, National Fuel Gas Distribution, and Hudson Electric & Gas; reinstatement of UTD by National Grid (2017) in a base rate case
North Carolina: Piedmont Natural Gas Company (Dockets No. G-9, G-21, and G-44)
Ohio: Duke Energy, (2014, docket no. not known)
Oklahoma: Oklahoma Natural Gas (Docket # PUD 200400610)
Oregon: NW Natural (2003, docket number not known), Avista (1998, docket no. not known)
Pennsylvania: National Fuel Gas Distribution Company (R-00049656.7), PECO, Columbia Gas of Pennsylvania (docket numbers not known)
South Carolina: Piedmont Natural Gas (Docket No. 2011-7-G, Case No. 2011-741) via O&M rider
Tennessee: Southern Co. Natural Gas Chattanooga Gas (2010, docket no. not known)
Texas: Atmos Energy (2011, docket number not known)
Utah: Questar (Docket No. 99-057-20)
Virginia: Atmos Energy (Case # PUE-2003-00507), Columbia Gas of Virginia (2017, docket number not known), WGL (2017)
Washington State: Purchased gas adjustments: Avista and Intermountain Gas
Wyoming: Questar (Docket No. 30010-GP-99-50, Record No. 5299)

GTI's revenues from its creation in 2000 until present day are shown in Figure 7. (Funding through 2004 includes FERC-approved funding.) GTI's funding had stabilized at $50-$60 million annually in 2005-2014. As part of this, OTD and UTD funding provided not only a base of $10-15 million per year, but served as the base for cofunding from DOE, CEC, NYSERDA, and other funding organizations. For instance, UTD dollars are leveraged at 4.5/1, OTD has a smaller leverage of about 1/1 ($1 brought in for every OTD dollar). Beyond 2014, GTI acquisitions[28] have substantially increased revenues, bringing the total revenue to over $100 million by 2016. It should be noted that, while energy related, not all is R&D and not all the R&D is natural gas R&D. Some energy efficiency deployment; evaluation, measurement and verification (EM&V), coal gasification, gas and electric kitchen appliances, and alternative power generation options are being pursued as well.

[28]On January 1, 2017 GTI International, Inc. (GTII) subsidiaries Fisher-Nickel, Inc., Davis Energy Group, Inc., and Bevilacqua-Knight, Inc. (BKi) combined to become a new company, Frontier Energy, Inc. Other subsidiaries include LocusView and CDH, with Aerojet Rocketdyne (ARI) merging with GTI.



Benefits of GRI/GTI R&D

After 40 years of R&D funding, GRI/GTI has a major portfolio of accomplishments. There have been many breakthroughs—some large, some small—all making a difference to gas consumers and the gas LDCs. As indicated, typical gas consumer benefit/cost ratios measured over five years of R&D costs and results ranged from 4/1 to 9/1.[29]

First and foremost, 30 years of unconventional gas R&D, culminating in the shale gas revolution, is saving gas consumers over $50 billion per year in gas costs. Major advances in coalbed methane and tight gas sands technologies have brought trillions of cubic feet of natural gas cost effectively to consumers. In the absence of adequate gas supply, consumers would have faced astronomical wellhead costs in excess of $10/MMBtu, as occurred in the early 2000s. In 2016, 48.4% of U.S. natural gas came from shale gas and oil resources, 15.8 Tcf. Over 2 Tcf came from coalbed methane.

In the end use area, the world's first high-efficiency furnace, the Lennox Pulse Combustion Furnace (now replaced by other models and with other manufacturers), has brought the consumer fully condensing 90%+ furnaces, revolutionizing the home heating market with a major furnace design change. From 50-75% of furnace sales in the northern tier of the U.S. are fully condensing units. Estimated consumer savings from high-efficiency furnaces are at least $1 billion per year. Similarly, 10 years of development and the recent commercialization of the Cannon Boiler Works Ultramizer condensing boiler has brought ultra-high efficiency furnaces to the commercial and small industrial boiler market. Boilers represent up to one-third of industrial gas loads, and the Ultramizer delivers 93% efficiency combined with very low emissions (NO_x < 5 ppm).

After 30 years, there is finally an engine-driven gas heat pump (GHP), with an equivalent heating efficiency of 160% on the market—the NextAire by IntelliChoice Energy.

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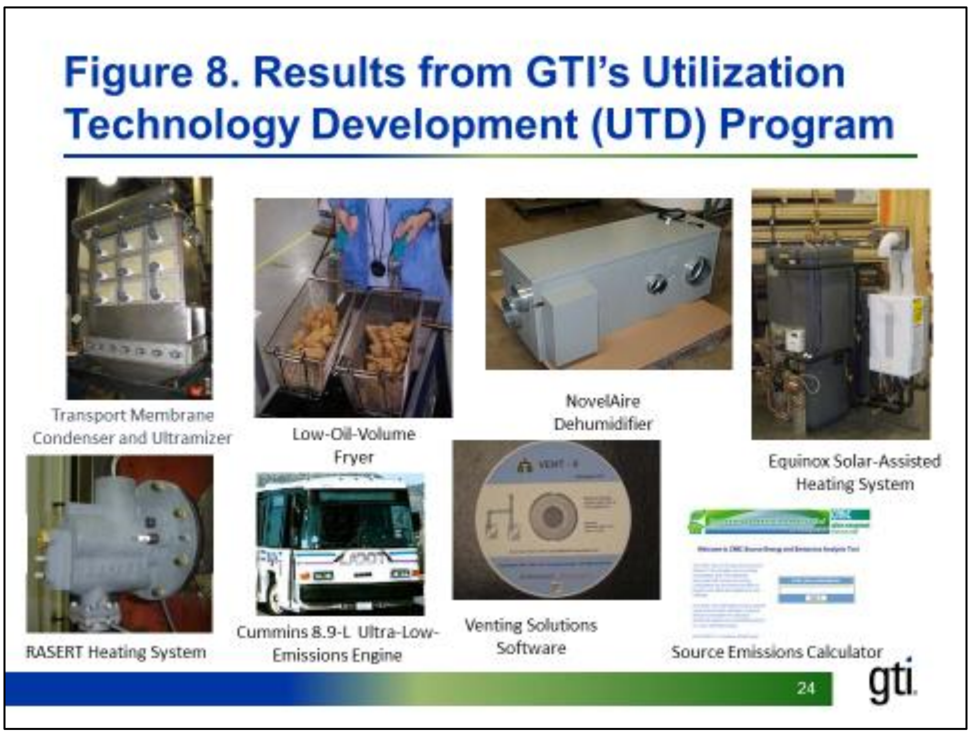
[29] See, for instance, "Benefits of GRI R&D Results that have been Placed into Commercial Use in 1997 through 2001," Athanasios D. Bournakis, University of Illinois at Chicago, May 2002, GRI-02/0074

Absorption GHP technologies are in development. The development and commercialization of 90%+ efficient tank-based (Vertex) and tankless water heaters was another notable advancement aided by research. An absorption GHP water heater (with equivalent efficiency of 138%) is in the latter stages of R&D. For the big-box store commercial market, the development and commercialization of condensing units by Munters for dedicated outdoor air systems provides the first (90% +) high-efficiency unit for this application.

In the NGV area, GRI/GTI has helped to develop and find commercializers for a variety of medium- and heavy-duty natural gas engines and compressed natural gas (CNG) components and systems. NGV engines developed and commercialized with GTI's assistance include the Cummins Westport (CW) 6.7L medium-duty engine, the CW 8.9L near zero emissions NGV engine for transit buses and refuse haulers, and the CW 11.9L heavy-duty engine for large trucks and buses. CNG components and systems include the 3M HyperComp lightweight CNG cylinders, the BRC FuelMaker PHIL compact home CNG fueling system, and the Ultimate CNG FuelMule for mobile refueling.

In the commercial cooking market, GTI-developed and commercialized products include the Frymaster low-oil-volume fryer, Royal Range Energy Star Frymaster, Montague high-efficiency broilers, Manitowoc Energy Star conveyor oven, Market Forge countertop steamer, and the Avantec Combi-oven.

Figure 8 shows a sampling of UTD R&D technologies brought to the marketplace.



With over 600,000 miles of plastic gas mains in the U.S. unable to be located when the tracer wire is inoperable, the plastic pipe locator provides a critical technology to the gas industry. This GTI-developed technology, brought to market by Sensit Technologies, took decades of R&D to perfect.

In the 1980s, horizontal boring was introduced to the gas operations area by GRI. Today, GTI technology has introduced field-based GPS locator systems and bar code technology to make gas assets placed in the ground traceable and trackable, providing manufacturing and materials specifications and more, even down to the level of identifying who fused the pipe. Figures 9 and 10 illustrate OTD technologies that have been commercialized.

Figure 9. Operations Technology Development (OTD) Market Impact (1)

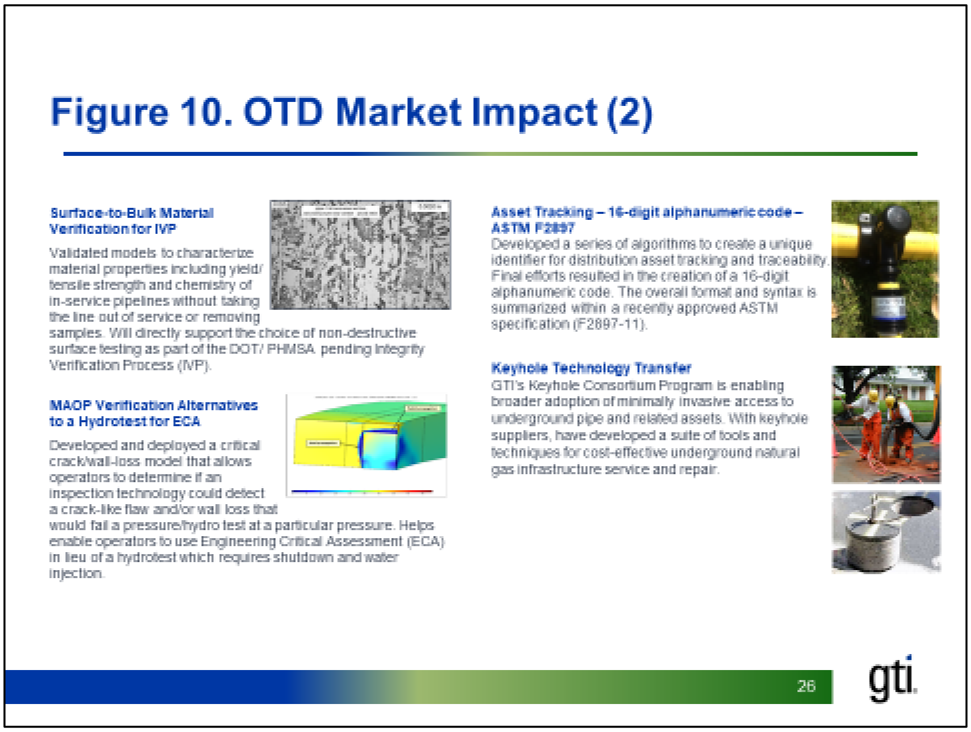


Figure 10. OTD Market Impact (2)

This R&D was not accomplished by GRI/GTI alone. Critical partners were LDCs and municipal gas companies, as shown in Figures 4 and 5. Federal and state agencies—including DOE and PHMSA, as well as CEC, NYSERDA, Illinois DCEO, and Minnesota Department of Commerce at the state level—were important funders and cofunders. Of course, research contractors, manufacturers, service companies, producers, and gas pipeline were all critical participants in the research.

DOE's Office of Fossil Energy, in particular, funded critical R&D in natural gas supply in the 1980s and 1990s, and GTI's Hydraulic Fracture Test Site (HFTS) in the 2010s, where understanding of hydraulic fracturing is being taken to a new level. DOE Energy Efficiency and Renewable Energy (EERE)-funded projects, many in partnership with UTD, resulted in the successful development and commercialization of the NextAire and IntelliChoice engine-driven GHPs with equivalent heating efficiency of 160%; the Vertex tank-based (90%+ efficient) fully condensing water heater; and the Ultramizer (93% efficient) condensing furnace. Their support today continues development of the Stone Mountain GHP water heater (equivalent efficiency of 138%).

Would all of this technology have made it to the marketplace without GTI and its partners and cofunders? No one can know for sure at what point a party from somewhere along the technology line might have stepped up to develop the technology and taken it to market. However, it might have happened decades later.

Where would the U.S. be today without the shale gas revolution? Possibly paying $10/MMBtu at the wellhead. Without the high-efficiency furnace, 80% efficient furnaces might still abound in the country today since there might not have been an incentive for an individual manufacturer to develop the unit.

It is often questioned whether manufacturers would have pursued this R&D on their own. For gas operations equipment, no manufacturer would have spent 30 years and tens of millions of dollars working on a plastic pipe locator, to sell 100 or so a year. Most appliance manufacturers sell both gas and electric equipment, so their initiative to develop higher efficiency gas equipment that exceeds codes and standards is low. And many of the small and medium-size appliance manufacturers have no R&D shop of their own.

Large E&P companies or gas field service companies might have done some of the gas shale research on their own. But the R&D would have been proprietary to their own company, and not spread throughout the industry and the country, delivering such broad-based benefits to gas consumers.

The cost of natural gas R&D has been appreciable, but the benefits to consumers and industry have been much higher. The costs to the nation of not performing the R&D would be incalculable, in terms of energy costs, resiliency, integrity, and national defense. The R&D has enabled natural gas to be an energy source not just for today, but for our children and grandchildren.

Acknowledgements

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Appendix C6-3

ADVISORY COMMITTEE ON INNOVATION, REPORT TO THE CHAIR OF THE ONTARIO ENERGY BOARD

Advisory Committee on Innovation

Report to the Chair of the Ontario Energy Board

Actions the OEB can take to advance innovation in Ontario's energy sector

November, 2018

Introduction

Consumer choices for energy services are changing, not just here in Ontario but around the world. Whether driven primarily by policy choice, advanced technology, customer expectations or emerging business models, the traditional means of supplying, delivering and using energy is in the midst of an important transition.

Emerging distributed technologies are providing customers with an increased ability to determine how their energy is provided and how they use it. Flexible demand, small distributed generation, fuel switching, energy storage, software solutions, advanced power electronics, and increasingly economic information and communication technologies are also providing utilities with new means to serve their customers.

Options for responding to growth in demand and maintaining reliable service, for example, now extend beyond the largely capital-intensive infrastructure development that has been the hallmark of energy service provision for decades. Today's energy consumers have a range of options to meet their reliability or adequacy needs, including a combination of the distribution utility, the customer's own assets and third party service providers. If the regulation of utility planning and investment decisions is not updated to consider and accommodate these new customer options when it makes sense to do so, utility customers may miss out on opportunities for better and more efficient service.

No one can say exactly how fast or to what extent transition will take place or what the eventual market structure will look like and it would be a mistake to try to predict a specific outcome. But few deny that change is happening and that distributors, whose role may be to adopt innovation as well as to provide the platform to enable others to do so, will be among those most affected.

Broad Actions to Support Innovation

The following broad actions should help to support innovation in energy services:

- Provide a transparent and level playing field by clarifying expectations and requirements regarding obligations between parties and towards customers
- Remove disincentives to innovative solutions by changing how utilities are remunerated, and introducing more systematic methods of valuation and pricing
- Encourage market-based solutions and customer choice by making more detailed and timely information available to sector participants
- Embrace simplified regulation by adopting simple and timely ways to allow for experimentation

While distributed energy resources (DER) and fuel switching are a relatively new influence in the energy sector here and abroad, they are not the only form of innovation. Innovation is much broader; it is implementing something fresh – either new or improved – to create value. Innovation can be transformative and effect fundamental change in a sector – in business models and in energy services. Innovation can also be incremental and achieve efficiency gains and cost savings for a utility or a customer. Innovation in regulation can spur transformative and incremental innovation in the sectors it regulates. Regulators, utilities and their customers engage in both types of innovation.

This Advisory Committee on Innovation was asked by the Chair of the Ontario Energy Board (OEB) to identify actions the regulator could take to create an environment to support innovation that brings value to customers.[1]

The Committee notes that the regulatory framework currently in place is not broken. However, it is not clear how well it will serve the future. Furthermore, it is unclear that existing policies that support innovation are being used in an optimal fashion, such as cost recovery for conservation activities that defer capital, or the availability of project-specific incentives. Finally, it is also unclear whether the current regulatory framework will enable customers to fully realize emerging opportunities to benefit from better and more efficient services made possible by evolving technology and business models.

The following broad actions should help to support innovation in energy services:

- **Provide a transparent and level playing field** by clarifying expectations and requirements regarding obligations between parties and towards customers
- **Remove disincentives to innovative solutions** by changing how utilities are remunerated, and introducing more systematic methods of valuation and pricing
- **Encourage market-based solutions and customer choice** by making more detailed and timely information available to sector participants
- **Embrace simplified regulation** by adopting simple and timely ways to allow for experimentation

The Committee discussed a broad range of issues, including some it understands the OEB does not have direct influence over. Two issues in particular the Committee discussed are critical to successful sector transformation – how people can adapt to change and how capital markets may respond to change. The former has to do with workforce development and business transformation – a key cultural issue considered globally to be an important

[1] The Committee's work and mandate are distinct from those of the Ontario Energy Board Modernization Review Panel. The Panel is an advisory body convened by the Government of Ontario to consider governance and the operational framework of the OEB, whereas the Committee's work focuses on innovation and supporting regulatory reforms.

enabler of innovation and one that applies across the spectrum of business, consumers, policy makers and regulators. The latter has to do with how markets perceive risk in regulation. A concern is that uncertainty regarding regulatory reform can negatively impact the way utilities fare in capital markets and can also impact how attractive the energy sector is to investors. A thoughtful and transparent process of regulatory change can actually alleviate risk of sector disruption. The OEB needs to take these broader cultural and market issues into consideration when implementing regulatory reform.

The Committee has focused its attention primarily on innovation and reforms to the regulation of the electricity distribution sector. However, the broad actions identified may extend beyond electricity distribution as opportunities for change arise in other areas that the OEB currently regulates, including gas distribution and storage, electricity transmission, generation, and the IESO-administered markets. Also, the Committee notes structural differences that exist between the electricity and gas sectors may offer insights into how regulatory regimes impact the ability to innovate.

The Committee believes its recommended actions are well suited to serve as a springboard for discussions at OEB consultations on the development of policies needed to support innovation in the sector, including how the recommendations in this report can apply to the gas sector. This is important if there is further convergence of these sectors in providing energy services to customers, for example, through fuel switching. As a general matter, the Board has recognized the value of symmetry in the economic regulation of electricity and gas distribution and that value may continue to apply when the Board considers how its current regulatory approaches may impede innovation.

In the consultations that address these recommendations, the Committee is confident that the business issues and actions it has identified can be more deeply examined in the Ontario context, and that policy options will be informed by jurisdictional review, empirical analyses, and the perspectives of stakeholders. And, of course, the OEB will be guided by its statutory objectives. The Committee believes, given the scope and complexity of the issues to be addressed, full sector engagement is required.

This report is structured as follows: a summary of recommendations precedes a more detailed discussion of each one. Examples of reforms underway in other jurisdictions are not endorsements; they are included to illustrate alternatives and potential lessons learned that may inform the OEB's consideration when it develops an approach suitable for Ontario. The report ends with thoughts on engagement and the sequencing of recommended actions.

The Committee is pleased to provide its recommendations to the Chair of the OEB.

This paper represents the advice of the Committee as a whole to the Chair of the OEB. It is not a consensus report or meant to represent the position or opinions of individual Committee members or their organizations. Accordingly, the positions and opinions of members and their organizations may not be reflected in the report, which is without prejudice.

Recommendations

1. Provide a Transparent and Level Playing Field

Consistent rules of engagement provide predictability and transparency to parties about their rights and responsibilities when engaging in various activities. To facilitate growth in new service arrangements that will deliver greatest value for consumers these concepts must be extended to and embrace new players in the marketplace. The OEB should further promote innovation through the following actions:

A. Improve the transparency and consistency of the distribution system connection process and clarify cost responsibilities to reduce uncertainty for DER proponents, utilities and consumers

B. Establish clear rules for DER integration into distribution systems, addressing technical matters including information, visibility, management and control to, among other things, protect the reliable and safe operation of the distribution system, and optimize the planning and management of resources and assets

C. Establish guidelines for commercial arrangements governing performance of non-traditional resources so utilities and others can rely upon them as alternatives to traditional system investment

D. Reexamine regulatory restrictions on utility business activities and review the separation of regulated and competitive services in light of new technologies and service expectations

Provide a Transparent and Level Playing Field

1A. Improve the transparency and consistency of the distribution system connection process and clarify cost responsibilities to reduce uncertainty for DER proponents, utilities and consumers

The OEB's framework around distribution system cost responsibility for connections aims to minimize cross-subsidies among consumers. Under current rules, which set out the process and timelines for connecting generators, utilities have significant discretion over connection requirements. Allowing utilities a degree of judgement is appropriate given utilities' responsibility to maintain the safety and reliability of their systems and that varying system configurations require different technical solutions.

However, consistency within and among utilities can make it less cumbersome for service providers to do business in Ontario. Transparency about how connection costs are determined can create more certainty for DER and other projects. It can also improve project development timelines. A process that encourages collaboration between utilities and proponents on configuration alternatives should support better outcomes.

Renewing the framework for connection processes and cost responsibility at the distribution level with a view to enhancing consistency and transparency, and considering its applicability to all forms of DERs, should be positive for all participants. A beneficial feature of the framework would be a timely and accessible process to resolve disputes between any interconnecting party and a utility.

1B. Establish clear rules for DER integration into distribution systems, addressing technical matters including information, visibility, management and control to, among other things, protect the reliable and safe operation of the distribution system, and optimize the planning and management of resources and assets

Distribution networks are part of a complex and dynamic system of supply, transport, and consumption of electricity. Utilities are responsible for providing a reliable delivery service and are expected to deliver that service efficiently. DERs on the distribution network beyond some level of penetration can create challenges to meeting those obligations and expectations.

Utilities can and do establish the means to protect their systems from adverse safety and reliability effects through automated protections and through utility control of isolation devices. For facilities located behind a customers' meter, utilities have little visibility let alone control of the output of the facilities. In some circumstances utilities simply limit how much supply can be connected to their network. If a utility has little or no visibility of a facility's operation and has no capability to manage it, whether directly, or through market signals, it has little option but to use these blunt instruments. These approaches will ensure reliability but do not take full advantage of the capability of distributed energy resources to be used to their potential in optimizing the operation of the distribution network and the broader system of which it is a part.

> *The California Public Utilities Commission provided guidance to the sector on storage providing multiple services to different entities or jurisdictions. The guidance addresses many issues related to the commercial development of storage, including the dependability of the services.*
>
> *California Public Utilities Commission. (January 2018). Decision on Multiple-Use Application Issues*

There are various ways that give a utility visibility and the ability to manage the output of any DER connected to its system to meet reliability obligations and optimize distribution assets as well as the DER. Options such as explicit regulatory obligations, facilitation of bilateral commercial arrangements, implementation of advanced distribution energy management systems, and development of new distribution-level markets, should be considered by the OEB. To the extent that DERs impact the integrated power system, new tools must be developed in concert with the distributor, DER proponent, the transmitter and the IESO.

1C. Establish guidelines for commercial arrangements governing performance of non-traditional resources so utilities and others can rely upon them as alternatives to traditional system investment

New technologies and business models create the opportunity for utility reliability and service quality obligations to be met using assets other than poles and wires, or by purchasing services.

If utilities are going to rely on other service providers or their customers services that displace distribution network investments, they will need to be assured that those services will be available when needed. Clear requirements for providing that assurance and consequences of not doing so will be needed.

Guidelines could pertain to a range of issues such as management and control, and consumer protection. To the extent that these can be standardized, it will give certainty to service providers and customers. It should also help overcome the challenges associated with diverse capabilities among utilities.

1D. Reexamine regulatory restrictions on utility business activities and review the separation of regulated and competitive services in light of new technologies and service expectations

Key questions in any discussion of the transformation underway in the energy sector are which activities need to be regulated, which should be competitive, and who may engage in each.

Customer needs are increasingly being able to be met by various technologies and service providers. Standard power quality from the grid may not always be sufficient for some customers, whereas others might prefer to pay less for a lower level of power quality. As utility customers take control of their energy bills and invest in their own solutions for reliability and power quality, the lines between regulated and non-regulated services are blurring.

The challenge for the regulator is to balance two important considerations. On one hand, the regulator must continue to ensure that monopoly service providers do not undermine competitive markets. Similarly, regulation should not create artificial monopolies, such as by deeming competitive services to be core distribution activities. On the other hand, the basic level of universal service, which is a social good, must continue to be available and broadly funded in order to provide a safeguard against erosion in service quality and cost performance for those who cannot self-supply.

Restrictions on regulated business activities have limited a utility's ability to offer new and differentiated regulated services. Unduly limiting the activities that utilities can engage in may impede the development of the most cost effective solutions in the future. The traditional regulatory view of universal reliability and service obligations of utilities may need to be redefined so that utilities can offer different services to different customers in ways that are more affordable, of greater value, or more innovative. Exploring this issue might also involve consideration of whether any regulatory obligations need to apply to entities who engage in distribution services but are currently exempt from OEB regulation.

> *Other regulators are turning their minds to this issue. For example, New York's Public Service Commission is establishing a process to differentiate competitive and regulated activities to determine how to treat revenue streams associated with facilitating a distribution-level market.*
>
> *New York Public Service Commission. (May 2016). Order Adopting a Ratemaking And Utility Revenue Model Policy Framework 14-M-010*

Recommendations

2. Remove Disincentives to Innovative Solutions

Putting nontraditional alternatives on an equal footing with traditional utility solutions can support pursuit of least-cost solutions with greatest value for consumers. To achieve this, the OEB should:

A. Remunerate utilities to make them indifferent to conventional or alternative solutions, including when other parties own and provide the alternative solution. Considerations will include, among other things, meaningful incentives and moving away from traditional rate base regulation

B. Establish an empirical evaluation methodology for cost-benefit comparison so all proposals are evaluated on a fair and consistent basis. Elements such as the value of optionality (i.e., the benefit of having options down the road), flexibility, location, time, resiliency, optimizing existing assets, and externalities as appropriate should be considered

C. Establish a way to ensure DERs can be compensated for their services commensurate with their value while paying their appropriate share of system costs. The approach should recognize new revenue streams which may be aggregated and allow shared cost recovery

D. Consider timely funding mechanisms to encourage utility innovation that provides near term customer benefits

Remove Disincentives to Innovative Solutions

2A. Remunerate utilities to make them indifferent to conventional or alternative solutions, including when other parties own and provide the alternative solution. Considerations will include, among other things, meaningful incentives and moving away from traditional rate base regulation

Utilities should be encouraging innovative solutions, including DERs, to meet their system needs when they are cost effective to do so. However, some utilities say, under the current revenue model, that they are not rewarded equally for their own versus alternate solutions. This arises from the fact that utilities earn a rate of return on capital but not on operating expenses. Some innovative solutions involve operating rather than capital expenditures – for example, a contract for demand-response to relieve congestion. Another example, from other sectors that have undergone similar transformations, is contracting for "software as a service" and data-driven solutions rather than making large investments in computer hardware. Other utilities say that this does not impact their decision-making and noted that the Board has several regulatory instruments that constrain capital investment, such as extensive prudential review and earnings sharing.

Pursuing least-cost solutions financed through operating expense may also be inhibited by price cap incentive regulation, which drives utilities to achieve efficiencies that lower their operating costs.

> *There are a range of approaches to achieving this, from targeted, benefit-sharing structures to more fundamental changes to conventional utility regulation. The UK's Office of Gas and Electricity Markets has adopted a "TOTEX" approach which includes the concept of allowing a return on total expenditures. The California Public Utilities Commission is piloting specific incentives to drive certain behaviours, for example, by allowing utilities to earn a profit margin on the value of contracts with third party DER providers.*
>
> *Advanced Energy Economy Institute. (January, 2018). Utility Earnings in a Service-Oriented World*

The OEB expects utilities to employ rigorous asset management processes to identify, pace and prioritize their investments. Without a change in the model for remuneration there is limited incentive to change from the past pattern despite the availability of new options that might provide the best long-term value for customers.

Removing any incentive for the utility to prefer one kind of spending over another should also provide customers and service providers more confidence that innovative solutions will be considered equally in the utility's planning process. The OEB should assess the range of options on their merits in a manner that considers both benefits and potential risks.

A key regulatory consideration will be how best to allocate the benefits of a third party solution between a utility and its customers. This will be particularly important when the solution involves the utility procuring the services of a third party that displaces an equivalent or more expensive investment by the utility.

2B. Establish an empirical evaluation methodology for cost-benefit comparison so all proposals are evaluated on a fair and consistent basis. Elements such as the value of optionality (i.e., the benefit of having options down the road), flexibility, location, time, resiliency, optimizing existing assets, and externalities as appropriate should be considered

One of the reasons utilities may not pursue innovative solutions is that developing a business case and defending it before the regulator and intervenors is more challenging and involves more uncertainty than continuing with the status quo. The business case for typical capital investments is tried and true; utilities have experience assessing asset-based options and defending them in an OEB hearing.

> *Common evaluation methods have been established elsewhere. A notable example is New York's direction to utilities to develop Benefit-Cost Analysis Handbooks setting out common methodologies for evaluating alternatives.*
>
> *New York Public Service Commission. (January 2016). Order Establishing the Benefit Cost Analysis Framework*

Innovative solutions may offer benefits that conventional solutions do not. Benefits such as optionality need to be captured to reveal alternative solutions that deliver long-term value, especially given that demand may be increasingly difficult to predict. For example, a distribution line amortized over its typical 45-year service life may appear less expensive than a battery amortized over 10 years. However, if the line is stranded in 10 years because demand is not what it was predicted to be, then the battery may have been the better investment. The flexibility to avoid stranding is a benefit that needs to be captured. At the same time, the Committee recognizes benefits such as these may not have been previously considered in an OEB hearing, and they may be challenged and tested more aggressively as a result, creating greater regulatory uncertainty.

Establishing a common evaluation method that accounts for all benefits associated with any particular solution will help put innovative solutions on equal footing with their traditional counterparts. It will also provide regulatory predictability when utilities bring forward innovative solutions since they would not have to justify the benefits included in their business case and how they were determined. It will aid the planning process by ensuring consideration can be given to all of the attributes of various alternatives.

2C. Establish a way to ensure DERs can be compensated for their services commensurate with their value while paying their appropriate share of system costs. The approach should recognize new revenue streams which may be aggregated and allow shared cost recovery

DERs can provide a variety of services to customers and utilities. For example, a storage solution can provide reliability assurance for a customer, a means of avoiding network investment for a distributor or a transmitter, and ancillary services for the system operator. Currently, some services are not valued and rewarded, particularly at the distribution level.

Today, DERs can be paid to provide services directly to customers. There are also well-established rules for services provided to IESO-administered markets. There are no such rules at the distribution level. Providing clarity and consistency on compensating DERs for their services, including appropriate valuation, could support growth of these types of arrangements. Distributors would then have a broader range of solutions to help them optimize their systems. Capacity relief, voltage regulation, and loss mitigation are examples of specific services that could be purchased from DERs.

> *Other regulators are adopting a wide range of approaches to address this issue. New York's platform service provider model is intended to address monetization of DER services. In this model, utility revenue may become more transaction-based rather than asset-based. At the other end of the spectrum, jurisdictions such as Hawaii and Nevada are looking at basing net-metering tariffs on the value provided, rather than on the retail cost of electricity.*
>
> *New York Public Service Commission. (May 2016). Order Adopting a Ratemaking and Utility Revenue Model Policy Framework 14-M-0101*

Furthermore, some of the services DERs can provide to others in the market require the distribution system for their delivery, yet there are limited ways (i.e., through the approval of a new specific service charge) to compensate distributors for facilitating these services.

2D. Consider timely funding mechanisms to encourage utility innovation that provides near term customer benefits

Currently, utility proposals for new and innovative technologies or business models are made through the rate application process. The large majority of utility costs to be covered by rates are for serving customers using established technologies. Any requests for funding through rates of new approaches are typically small in comparison.

Jurisdictions such as California, New York and the United Kingdom have reduced barriers and used consistent ratepayer funding models to drive change.

In the UK, three sources of funding are available to gas and electric utilities for innovative projects: a utility allowance, as a percent of revenue, for small projects related to their own networks; a pooled fund for research, development and demonstration of new technologies; and a pooled fund to help utilities transition a proven innovation into business as usual. Access to the latter two funds are on a competitive basis.

Office of Gas and Electricity Markets. (December 2017). RIIO Electricity Distribution Annual Report 2016-17

Innovation can entail a higher than normal risk that a proposal will fail to deliver benefits to consumers. There is a concern that the rate-setting process may not be the most effective venue for exploring bold new approaches. This may hamper proposals from being brought forward.

Gas and electric utilities can accelerate the cost-effective commercialization of innovations. Allowing utilities a relatively small amount of funding, collected through rates but separate from normal business operation and deployed with an efficient level of oversight may be an effective means of encouraging breakthrough approaches. Utilities often have the scale, reputation or markets to provide a launch pad for introducing innovative products.

Recommendations

3. Encourage Market-Based Solutions and Customer Choice

Information transparency is key to developing and deploying new market-based solutions. It expands the options for utilities to consider in their service offerings and enables informed consumer choice. In order to facilitate better access to information, the OEB should:

A. Require utilities to publish information about the characteristics and capabilities of their systems to enhance transparency of distribution system needs and capabilities within the market

B. Encourage cost-effective investment by utilities in monitoring and control capabilities to the extent that these enabling investments will help them efficiently manage a more dynamic distribution system

Encourage Market-Based Solutions and Customer Choice

3A. Require utilities to publish information about the characteristics and capabilities of their systems to enhance transparency of distribution system needs and capabilities within the market

In order to develop innovative solutions for utilities the market must know what they need. If a basic level of information about distribution system needs is available – currently there is no requirement or incentive to do so – the market can respond.

Transparency of distribution system characteristics and capabilities can also support efficient customer- and market-led solution deployment. The value of resources can be quite different depending on where they are located on the network and when they are used. Factors such as how easily new resources can be accommodated in a given area (sometimes referred to as "hosting capacity") and opportunities to sell utilities services located to relieve capacity constraints can inform both consumer investment decisions and the development of market services.

Revealing distribution system needs and capabilities to the market can generate value for consumers in two ways. First, there is value in broadening the range of options considered by a utility to help them identify least-cost solutions with long-term value. Second, there is value in revealing more opportunities for consumer and market-led investment.

This being said, there are a number of considerations that the Board should consider in determining what data should be provided and who should have access to it. These considerations include safety, privacy, security and commercial sensitivity.

In New York, each utility is required to publish a map identifying areas where higher project compensation is available to meet an acute need. Zones, capacity caps, and values are approved by the Public Service Commission.

In Ontario, bulk system needs are revealed each quarter as the IESO publishes its 18-month outlook describing zonal demand and supply characteristics, system capability of interfaces between zones, and energy flow on those interfaces. Market information is available to identify constraints on the system.

New York State Energy Research & Development Authority. (October, 2017). Summary of Value of Distributed Energy Resources

Independent Electricity System Operator. (October, 2018). 18-Month Outlook

The Committee believes the market may value more granular distribution system information, beyond a basic level to be made available to all. Other service providers may be willing to pay for information beyond the basic level to help them develop service offerings. Currently there is limited information available about the injections or withdrawals of energy and even less about other attributes like voltage and momentary service interruptions. Where information is available, it is often on a timescale (e.g., monthly, daily, hourly) that is too long to be useful. This additional level of information may be a new value-added, user-pay utility service offering and could be an example of a differentiated utility service.

An important factor to consider – whether basic or more granular information is provided – will be ensuring privacy and security measures are central to the design of an approach for making information available.

3B. Encourage cost-effective investment by utilities in monitoring and control capabilities to the extent that these enabling investments will help them efficiently manage a more dynamic distribution system

Utilities install monitoring and control equipment to be able to know what is happening on their system and to be able to take action to isolate problems and restore service to customers. As new technologies have begun to connect to their networks and to their customers' facilities, managing the reliable operation of their systems has become more complex. At some level of penetration of DERs, utilities will not be able to effectively plan and reliably operate their systems if they do not have visibility of and the ability to manage all facilities that are using or impacting their systems. This could result in legitimate denials of connection or limitations on dispatch for reliability reasons. It could also prevent new resources from being managed in a way that optimizes their functionality to the benefit of the system

Eventually, if enough new resources are connected to distribution systems, they will have to be dynamically managed similar to the bulk system. We may need a distribution system operator(s) with many of the capabilities of the IESO. If a true retail market develops for competitive services, the capabilities of the distribution system operator will be even more important. Ideally, the installation of monitoring and management equipment will precede the need, thereby facilitating cost effective deployment of DERs. Therefore, it needs to be considered early in the planning process.

Monitoring and control equipment paired with intelligent analytics can maximize capabilities. This is a key learning from the telecom sector – with the advent of cellular technology was the need for investment in advanced software and data-driven solutions, particularly big data analytics, as an alternative to traditional hardware.

Supportive regulatory guidance could be developed to increase utilities' confidence to propose these enabling investments. Progressive improvements in monitoring and management capability are an important part of realizing the full benefits of energy sector transformation. Furthermore, these enabling investments can also serve multiple future designs for the sector, including potential for transactive markets at the distribution level.

Recommendations

4. Embrace Simplified Regulation

Regulatory processes serve an important purpose but their complexity and pace is not conducive to deployment of innovation. Consumers, utilities and innovators in the sector need a simple and timely way of trying things out and learning from their experience. Regulatory simplicity will result in better pathways for innovation. In order to embrace simplified regulation, the OEB should:

A. Provide a means by which both utilities and unregulated entities are encouraged to discuss specific regulatory obstacles with the OEB, in order to allow near-term deployment of innovations while longer-term regulatory reforms are implemented

B. Review the information the OEB collects to ensure it is used to evaluate performance in the sector – specifically whether utilities, other service providers and regulation itself are benefitting customers

C. Explore the use of self-executing processes that use transparent, pre-approved criteria to allow streamlined regulatory review

D. Further examine OEB decision timelines to determine whether they can be shortened without compromising the effectiveness of stakeholder participation

Embrace Simplified Regulation

4A. Provide a means by which both utilities and unregulated entities are encouraged to discuss specific regulatory obstacles with the OEB, in order to allow near-term deployment of innovations while longer-term regulatory reforms are implemented

It is unclear whether the OEB's outcomes-based approach to regulation has advanced innovation in the sector to the extent it was intended. The complexity of utility filings and the adversarial nature of OEB hearings may be an obstacle to innovation and experimentation by consumers, utilities, and innovators.

Consumers, utilities and innovators in the sector need a simple and timely way of trying things out. This can be done by creating a venue in which proponents – whether regulated utilities or competitive service providers -- can bring forward innovative projects, identify regulatory constraints and illustrate the benefits if a particular regulatory barrier were addressed. It would enable the OEB to 'pilot' innovative regulatory approaches. Such a forum, commonly called a 'regulatory sandbox' in some jurisdictions, may reveal opportunities for proponents to proceed without further regulatory review or intervention, or afford the opportunity for temporary relief of regulatory requirements for a trial period.

Setting aside conventional regulation and allowing utilities to use a regulatory sandbox will be a key modernizing tool that utilities can use to streamline adoption of innovation. This is crucial to reducing any barriers to innovation in conventional regulation. A sandbox may also help the OEB to ensure that current enabling policies (e.g., conservation and demand management allowances and infrastructure investment incentives), are effective and encourage utilities to take full advantage of them. Clarity and simplicity in processes are the essential elements for this approach to be a success. Development of a simplified framework can help overcome speed and scale issues allowing flexibility to do what is best for customers and quickly implement innovative technologies.

> *In the UK, the Office of Gas and Electricity Markets has implemented a "regulatory sandbox" to enable innovators to trial business products, services and models that cannot operate under existing regulations. What it calls "fast, frank feedback" is available to assess whether a proposal could operate under the current regulatory framework. If regulatory barriers exist, innovators can then apply for trial regulatory treatments to support their proposal.*
>
> *Office of Gas and Electricity Markets. (October 2017). Regulatory Sandbox Window 2 Guidance*

4B. Review the information the OEB collects to ensure it is used to evaluate performance in the sector – specifically whether utilities, other service providers and regulation itself are benefitting customers

Information about utility operations and performance is a cornerstone of performance-based regulation. While seemingly burdensome, it has the potential to make regulation less intrusive than traditional cost of service style regulation, which scrutinizes utilities' spending and decision-making. This less intrusive approach would require a commitment by hearing panels to ensure that hearings do not simply replicate cost of service reviews and that decisions are focused on the evaluation of performance against objective performance standards.

The information that the OEB collects to support its regulation could also serve market development. In other recommendations, the Committee identifies the need for better information sharing. To the extent that the OEB is already collecting the information, efficiencies can be achieved if the information were made public. It could be synthesized into a useful Ontario energy sector resource and made publicly accessible in a user-friendly way.

> *In the United States, the development of sophisticated benchmarking models by energy regulators and utilities has been enabled by data that has been gathered over the years by the Federal Energy Regulatory Commission.*
>
> *Federal Energy Regulatory Commission. (September 2018). Form 1 - Electric Utility Annual Report*

The OEB should periodically review its reporting requirements and eliminate any that do not meaningfully contribute to its oversight of the sectors.

4C. Explore the use of self-executing processes that use transparent, pre-approved criteria to allow streamlined regulatory review

Recommended enhancements to regulation described in this report should facilitate streamlined approvals. Once utilities choose from a broader range of solutions that are valued and rewarded in a consistent manner, less granular scrutiny of investment proposals should be needed. The OEB should take this a step further by establishing a streamlined, self-executing process.

Using this approach, proposals selected and planned in accordance with prescribed criteria would require no further regulatory approval to proceed. Any after-the-fact review of utility performance would focus on learning from experience in the interests of continuous improvement rather than on a hindsight critique of what a utility could have done differently. For instance, the OEB could set standards for a distributor's comparison of in-house options with external options. Any distributor following that process would meet the requirements of prudence without further review. This approach should facilitate more innovation during a multi-year rate term, and would enhance the OEB's outcomes-based approach to regulation.

4D. Further examine OEB decision timelines to determine whether they can be shortened without compromising the effectiveness of stakeholder participation

The current length of many rate cases is not consistent with innovation. Within the time it takes for a rate case to be adjudicated, much can change in the sector outside of a regulated utility. Utilities have an important role to play in enabling and adapting to innovation to create value for consumers, either directly through delivering energy more efficiently, or indirectly by enabling new innovative services offered by other service providers. The regulator has an important role to ensure those they regulate are prudent with ratepayer dollars and that they uphold their obligation to serve all customers at a reasonable cost.

The Committee notes that the OEB is in the midst of a review of its adjudicative model with a view to introducing proportionate regulatory reviews. To the extent that lengthy regulatory approval processes hinder the deployment of innovation in Ontario, the OEB should consider whether and how its regulatory processes can be shortened.

Engagement and Sequencing

The Advisory Committee on Innovation was asked by the Chair of the OEB to identify actions the regulator could take to create an environment to support innovation that brings value to customers.

The broad actions described in this report should help to support cost-effective innovation in energy services. A rules-based approach to regulatory approval should provide greater transparency and certainty in the sector. Changing how utilities are remunerated should encourage them to select from a broader range of choices to serve their customers. Making information available in the market should spur development of more energy services. Simplified regulation that supports utilities, innovators, and customers should accelerate sector innovation. The recommended actions can accommodate a range of possible futures.

The scope of the Committee's recommended actions suggests a need for multiple policy development streams that coordinate and accommodate timely and appropriate deliberation of regulatory reforms. The actions are well suited to serve as a springboard for discussions at OEB consultations. The Committee encourages all sector participants to engage with the OEB in these consultations.

The Committee was also asked for its help on prioritizing and sequencing of actions. Some actions can proceed independently, while others are intrinsically linked and would benefit from a coordinated approach. For example, work to improve the connection process and work to make distribution system characteristics available can proceed quickly and in parallel. Progress on these fronts can inform work on commercial arrangements, DER integration and compensation. At the same time, looking at how utilities are remunerated, while complex and thus likely to proceed in a measured way, can be initiated quickly and independently. This may also be the case for developing an empirical evaluation method to compare alternatives. Furthermore, while implementing a regulatory sandbox can get underway soon, examination of funding mechanisms could inform the evolution of the sandbox. This illustrates the complexity and potential interrelationships between the issues and actions.

As a next step, the Committee suggests that the OEB host a stakeholder event (perhaps along the lines of a FERC technical conference) to get broader input on subsequent OEB work, including prioritizing and sequencing of actions. Figure 1 on the next page illustrates the Committee's thoughts on sequencing and an indicative timeline.

To help the Committee understand the potential impacts of its recommendations on the OEB's regulatory framework, it endeavored to map each proposed action against key elements of the OEB's regulatory framework. Table 1 summarizes potential regulatory touchpoints for OEB consideration.

Figure 1: Recommendations - Indicative Timeline

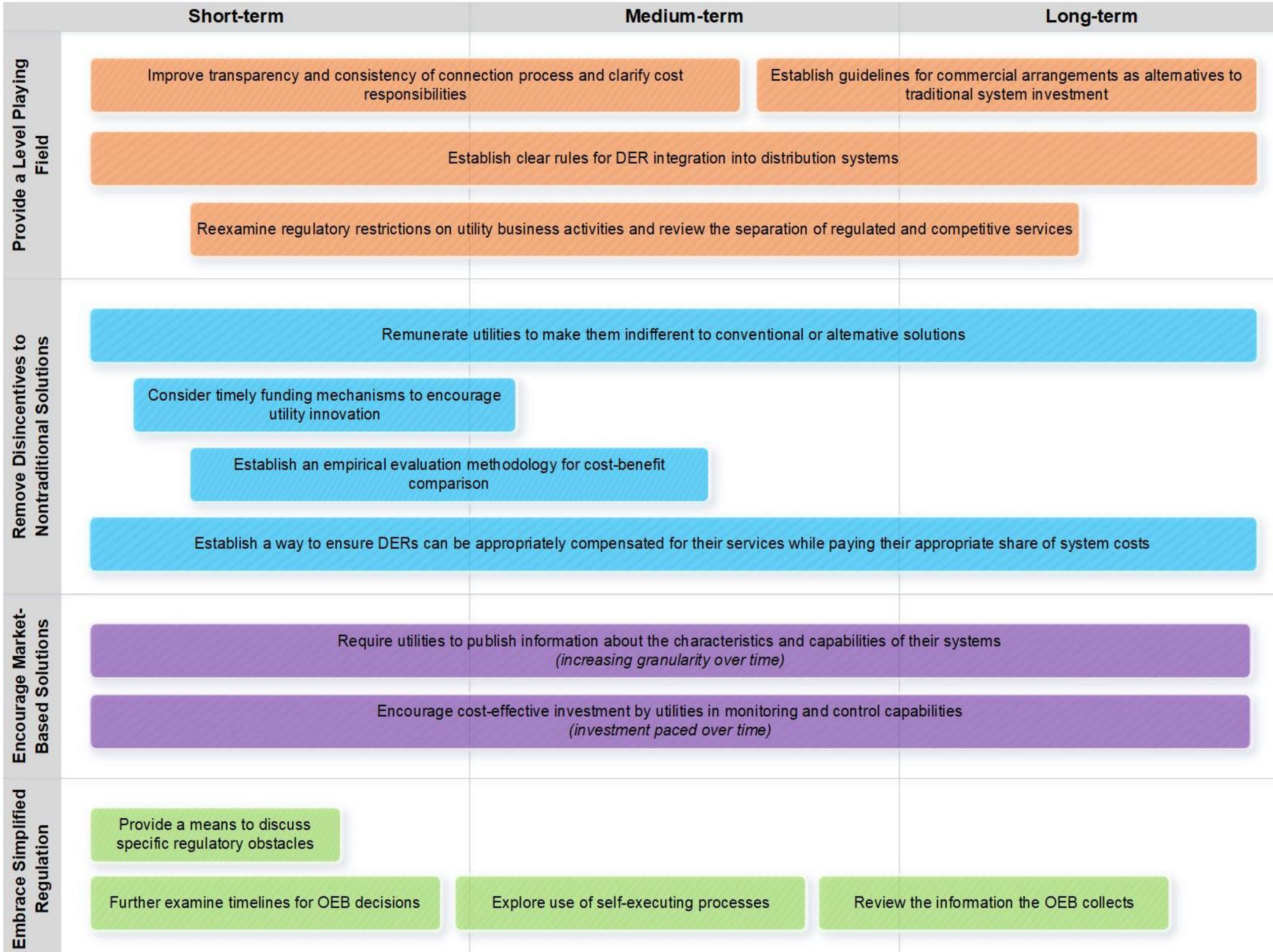

Table 1: Regulatory Touchpoints

	Recommended Actions	Licencing	Codes & Rules	Guidelines	Rate Regulation	Service Quality	Performance Monitoring	Audit	Compliance	Decision-Making
Level Playing Field	Improve transparency and consistency of connection process and cost responsibility		●				●	●	●	
	Establish clear rules for DER integration into distribution systems		●				●	●	●	
	Establish guidelines for commercial arrangements as alternatives to traditional system investment			●						
	Reexamine regulatory restrictions on utility business activities and separation of regulated and competitive services	●	●	●				●	●	
Remove Disincentives	Remunerate utilities to make them indifferent to conventional or alternative solutions			●	●		●			
	Establish empirical evaluation methodology so all proposals are evaluated on a fair and consistent basis			●						
	Ensure DERs can be compensated for their services while paying their appropriate share of system costs		●	●						
	Consider timely funding mechanisms to encourage utility innovation			●	●		●	●		
Market- Solutions	Require utilities to publish information about the characteristics and capabilities of their systems		●	●		●	●	●	●	
	Encourage cost-effective investment by utilities in monitoring and control capabilities			●		●	●			
Simplified Regulation	Provide a means by which both utilities and unregulated entities can discuss specific regulatory obstacles with the OEB			●						●
	Review the information the OEB collects to ensure it is used to evaluation performance in the sector						●			
	Use self-executing processes that use transparent, pre-approved criteria to allow streamlined regulatory review			●						●
	Further examine OEB decision timelines to determine whether they can be shortened			●						●

Appendices

Committee Membership

Brian Bentz - President and CEO, Alectra Inc.

A J Goulding - President, London Economics International LLC

Anthony Haines - President and CEO, Toronto Hydro Corp.

Cynthia Hansen - Executive Vice President, Utilities & Power Operations, Enbridge Inc.

Krista Jones - Managing Director, Work and Learning, MaRS Discovery District

Nicole Martin - Senior Director, Standard & Poor's Global Ratings

Paul Murphy - Chair Advisory Board, Advanced Energy Centre at MaRS

Jason Sparaga / Andrew Clark - Co-Founders and Co-CEOs, Spark Power Corp.

George Vegh - Counsel, McCarthy Tétrault

Adam White - Founder and CEO, Powerconsumer Inc.

Joshua Wong - President and CEO, Opus One Solutions

Committee Process

The Committee held a series of discussions over the last eight months structured around the following themes; new services, value and pricing, planning, and remuneration. Early meetings focused on identifying and describing business issues – particularly issues utilities, innovators, consumers and the regulator face when pursuing innovation. Later meetings focused on identifying potential actions the regulator could take to address those issues.

Committee members engaged in open discussions supported by material prepared by OEB staff and by presentations by committee members. While Committee discussions were assisted by external studies and reports, particularly those from MIT and Mowat, the Committee drew heavily on the practical experience and knowledge of its members. Primary research was not carried out. All materials prepared by OEB staff and other reference materials are listed below, as are the summary notes of the Committee discussions.

Links to Committee Materials

Terms of Reference

Committee Member Profiles

Meeting Materials

This paper represents the advice of the Committee as a whole to the Chair of the OEB. It is not a consensus report or meant to represent the position or opinions of individual Committee members or their organizations. Accordingly, the positions and opinions of members and their organizations may not be reflected in the report, which is without prejudice.

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Appendix C6-4

MAIN INNOVATION ACTIVITIES

MAIN INNOVATION ACTIVITIES

This appendix describes the Innovation Fund's main innovative activities including the likely technology readiness levels (TRL).

1.1 *BLENDING HYDROGEN [TRL-3 TO TRL-6]*

FEI plans to investigate the feasibility of blending hydrogen into its natural gas delivery system, providing access to a clean and sustainable energy source. Blending hydrogen with natural gas using the existing natural gas pipeline network could be an effective means of delivery of lower carbon energy, potentially connecting hydrogen sources to end users with relatively little significant additional investment in infrastructure. FortisBC Energy Inc. (FEI) will also investigate the potential to deliver renewably sourced hydrogen and methanized hydrogen, a synthetic equivalent to natural gas methane, using its natural gas delivery system. Other related opportunities FEI and FortisBC Inc. (FBC) (collectively FortisBC) is assessing include power-to-gas technologies that bridge the traditional electrical power grid and natural gas delivery system.

As noted above, FEI is planning to undertake pilot projects to allow FEI to explore the introduction of hydrogen into the natural gas delivery system. FEI intends to initiate two hydrogen injection pilot projects in 2019 . Should the technologies that allow hydrogen to be blended into the conventional natural gas distribution system prove to be technically and commercially viable (including safety and operational considerations) and acceptable to customers and stakeholders, FEI proposes that it would then come forward with an application for funding to support a more extensive deployment of hydrogen production and integration technologies.

Integrating renewable energy resources in this way could provide a green source of hydrogen that would enable FEI to further reduce GHG emissions associated with B.C.'s energy infrastructure.

1.2 *RENEWABLE NATURAL GAS [TRL-2 TO TRL-6]*

With its abundance in British Columbia, wood waste as a feedstock for RNG offers considerable potential. There is a significant opportunity for FEI to unlock this potential by supporting third-party development activities in the Province's wood waste feedstock. To evaluate this opportunity, FEI plans to undertake a project to produce RNG using wood waste as a feedstock.

The first phase of this project will address two areas. First, work will be done to identify optimal locations for securing a source of biomass and for connecting to the natural gas infrastructure in B.C. with a preference for FEI-owned and operated locations. Second, FEI would fund third-party research into tar cracking, pyrocatalytic hydrogenation, optimizing methanation catalysts, and other research avenues. This work would be done with private organizations already operating in B.C. (i.e., G4, FP Innovations and Nexterra) and by engaging research labs at UBC and UNBC already working on this technology. The focus will be on promising technology innovation that can directly address key challenges. The work will begin with a thorough technology scan and literature review to leverage any existing work being done around the world.

In the second phase, pilot equipment and technology will be needed to run a biomass-to-RNG facility. This would include support for technology demonstrations for activities such as methanation catalysts and carbon sequestration. Towards the end of this phase, a methanation reactor will be piloted on an already existing wood gasification system. Both UBC and UNBC operate small demonstration gasification systems. Engaging with one or both of these universities would be an ideal way to test methanation technology on a pilot scale.

1.3 *CARBON CAPTURE [TRL-2 TO TRL-6]*

Carbon capture is the process of capturing waste carbon dioxide and either storing it in an underground geological formation or to use that captured carbon dioxide to make other substances such as plastics, concrete and even biofuel. GHG emissions can be dramatically reduced through the utilization of carbon capture technologies in conjunction with end-use applications in both the built environment and industrial processes. FEI is exploring those end-use carbon capture technologies and is currently conducting a small-scale pilot with Clean 02 (a manufacturer of an end-use carbon capture device called Carbonix) to test and demonstrate energy efficiency and GHG reductions of up to 10 units. Clean 02 claims that the Carbonix unit reduces energy costs by increasing hot water efficiency through heat recovery as well as reducing greenhouse gas emissions by capturing and converting flue gas emission to a by-product. The carbon capture process creates a soda ash or a pot ash by-product which is then collected and sold by Clean 02 to the open market under a commodity profit sharing agreement with the building owner. Since this particular technology may both save both energy as well as creating a by-product using captured carbon dioxide, FEI considers it both a DSM and a non-DSM activity. Funding for costs such as M&V equipment to measure energy savings and incentives for the unit are eligible to receive DSM funds from the Innovative Technology program area while costs pertaining to measuring emission reductions and by-product production were covered from O&M. FEI believes additional Non-DSM funds will be required to explore and research carbon capture technologies similar to Clean 02 as well as supporting the commercialization of the technology category.

1.4 *NON-DSM CONSUMER END USE TECHNOLOGIES AND SYSTEMS [TRL-4 TO TRL-8]*

Improvement through innovation is at the forefront in how FortisBC interacts with its customers. In this regard, FortisBC has consistently worked with customers to meet their energy requirements. FortisBC has strong relationships with HVAC contractors through the Trade Ally program, and builders, developers, architects and engineers with our sales teams, and manufacturers and retailers. Often when working with builders and developers, a need is expressed for a heating or energy solution that is not commonly used or for a solution that is not yet developed. Some of those solutions may be eligible to receive DSM funding but others that don't meet the cost effectiveness test, program eligibility requirements or meet the DSM definition may be covered from the O&M budget or not at all. In these situations, FortisBC works with manufacturers, retailers, and HVAC contractors to devise a workable energy solution for the developer.

An example of such a technology is Combined Heat and Power technology that utilizes natural gas to generate electricity and supply heat. Although these units can already be operating at efficiencies of 75 percent or higher, FortisBC is interested in furthering development of more efficient CHP units. However, CHP units are generally ineligible for DSM funding since the majority of installations are in new applications where natural gas use may actually increase. Despite this, FortisBC believes it is important to continue researching efficiency improvements in this technology.

Keeping in mind that FortisBC expects the existing gas distribution pipelines to be carrying a product that is increasingly clean, it is important to continue researching both gas and electricity end-use technologies that are not currently eligible to receive DSM funding but have the potential to expand efficient, affordable gas and electricity end-uses in the future for the benefit of its customers.

1.5 *NATURAL GAS FOR TRANSPORTATION (NGT) [TRL-3 TO TRL-6]*

Natural gas in the form of CNG or LNG end-use technologies, is a cost-effective transportation fuel to replace the diesel used in road, marine, rail and off-road applications, while also reducing GHG emissions. In B.C, and in North America generally, there is an abundance of low-cost, relatively easy-to-access natural gas commodity resource, which means that NGT fuel offerings have a price advantage over petroleum fuels.

In order to maximize the adoption of CNG and LNG uses for transportation, FEI plans to investigate a number of innovative technologies. The following is a discussion of some of the RD&D activities FEI plans to be involved in.

1. Canadian Standards Association (CSA) Compressed Natural Gas Tank Technology

   The CSA is in the process of evaluating different CNG tank technologies that would enable higher filling pressures, which would increase the amount of fuel that a vehicle could carry on board, thus increasing operating range.

   The development of this innovation would impact the following key components:

   - Fuelling infrastructure configuration: higher compression capacity
   - CNG vehicle fuel storage configurations
   - Development of codes and standards to ensure consistency and applicability of such codes/standards across industry

2. Adsorbed Natural Gas Tank Technology

Adsorbed natural gas (ANG) process enables the filling of CNG fuel tanks at a much lower temperature and pressure (<1,000 psi for ANG, as opposed to 3,600 psi for traditional CNG tanks) through an Activated Charcoal acting as an adsorbent material with high surface area that can be used in ANG storage tanks. This results in much lower fueling station capital required to enable fueling for ANG tanks because the compressor capacity is greatly reduced. Currently, researchers are developing new adsorbents with higher adsorption ratio to optimize this process.

The development of this innovation would impact the following:

- Fueling infrastructure modifications required to enable ANG fueling
- Vehicle modifications to tanks and rail configurations
- Development of codes and standards will be required for ANG tanks

Developing ANG would enable a more efficient utilization of on-vehicle space for fueling tanks as ANG tanks are square or rectangular in shape, while traditional CNG tanks are spherical. Additionally, ANG enables much smaller compressor capacity to achieve the same fuel capacity as traditional CNG fueling. As a result, the cost of ANG enabled vehicles would be lower than traditional CNG tanks due to a reduced need for high pressure tankage. ANG could help unlock the light-duty vehicle market as ANG tanks would enable customers to fuel their vehicles by tapping directly into the utility pipeline/meter at home without the need for high capacity compression equipment.

3. Reduce fugitive emissions in fueling procedures from CNG fueling stations (includes methane slip during combustion in dual-fuel applications)

There is a need to understand the potential fugitive methane emissions that could occur during compression and fueling of CNG vehicles from our CNG stations. Presently, any gas that is not dispensed into the vehicle during fueling is not recovered and is vented to atmosphere via a vent line located at the top of the CNG dispenser. CNG compressor technology also needs to evolve to reduce the amount of fugitive emissions that occur during the compressor cycle of the CNG gas dispensing chain. Presently, FEI believes that methane slip does occur during the compressor cycle (i.e. compressing pipeline gas up to 3,600 psi) due to leakage at the compressor seals, but quantification is required to better understand the total impact.

Potential solutions could be explored to mitigate the fugitive emissions if material enough to justify the investment in mitigating measures, but quantification is required first. Potential mitigating solutions could be recovery of vented gas and transferred back into the dispensing line for future CNG transfers. In terms of reducing methane slip at the compressor cycle stage, FEI can work with original equipment manufacturers (IMW and ANGI predominately) to understand the impact of slippage and potential mitigating solutions.

4. Mobile CNG fueling capability

   Technologies that enable the fueling of CNG trucks using mobile CNG fueling equipment would be a game changing development for the on-road trucking segment. For fast-fill applications and regardless of the number of trucks, the capital requirement to provide fast-fill capability can be prohibitively high due to the amount of compression equipment required.

1.6 *HYDROGEN FOR TRANSPORTATION [TRL-2 TO TRL-4]*

Hydrogen has been the "fuel of the future" for many years and recently seems to be gaining traction. Disruptive companies like Tesla, emission regulations, and increased consumer awareness have pushed the automotive industry into a period of transition and have contributed to the increased focus on use of hydrogen as a clean transportation fuel source.

Hydrogen can be produced from diverse feed stocks such as from renewable energy sources like wind, solar, and hydroelectric and from other energy sources like nuclear energy, and fossil fuels. Different procedures can be employed to create hydrogen like chemical, electrochemical and biological process technologies. Compressed hydrogen has 200 times the energy density than lithium-ion batteries and 2.9 times more per kg than diesel. The combination of a hydrogen fuel cell and compressed hydrogen cylinders provide an electrical current that can power electric motors. Other cleaner technologies are limited by the energy density, storage, efficiency in converting energy into motion, and well-to-wheel emissions. As indicated, combustion or use of hydrogen in fuel cell vehicles results only in water vapor emissions.

The Capital Regional District (CRD) is currently replacing eight internal combustion engine vehicles with six fuel cell electric vehicles (EV) and two battery EVs for testing and studies. The CRD is targeting to replace up to 100 internal combustion engine vehicles with zero emissions alternatives as part of its fleet renewal. The hydrogen cars will be on the road this fall refueling at the HTEC/Shell station. For this initiative, the CRD received funding from a number of sources including the Green Municipal Fund, Western Economic Diversification Canada's WINN program, BC Ministry of Energy and Mines (MEMPR) Clean Vehicle Program and Low Carbon Fuel Regulations.

There is the potential for FEI to supply energy to this emerging market by providing fueling infrastructure to anchor tenants such as municipalities and commercial accounts, utilizing FEI's existing infrastructure.

FEI will continue to monitor developments in the hydrogen for transportation sector and look for RD&D opportunities that would complement investments in hydrogen blending and advance development for the benefit of customers.

1.7 *ELECTRIC VEHICLES (EV) AND CHARGING STATIONS [TRL-4 TO TRL-6]*

FortisBC supports EV charging infrastructure expansion, and recognizes the important role that the utility can play in promoting a local market transformation. Transition to EVs will support government GHG reduction targets, particularly since 96 percent of FBC's electric resource supply is from low carbon renewable sources including hydroelectricity. Personal transportation is currently responsible for approximately 13 percent of B.C.'s greenhouse gas emissions. The potential GHG reductions associated with the electrification of vehicles are substantial.

FBC's efforts are focused on advancing the development of EV charging to support adoption of EVs. Range anxiety has been identified as a key social barrier to EV adoption. It is acknowledged that electrifying highway corridors, and connecting urban regions with EV charging infrastructure will address a key concern for prospective EV drivers, that being their freedom of movement and ability to travel with their EV without concern for access to charging infrastructure. Research compiled by the University of British Columbia Transportation Infrastructure & Public Space Lab (TIPS Lab) finds that "*Locating each station strategically within the introduction of the broader network is key to the success of the charging infrastructure and the overall adoption of EVs.*"[1].

FBC's focus is to support the expansion of EV charging infrastructure recognizing the role that the utility can play in supporting a local market transformation while establishing a network that will result in numerous regional co-benefits, such as tourism and economic development. FBC's efforts will provide the infrastructure necessary to catalyze the adoption of EVs in B.C.'s Southern Interior, helping to facilitate the achievement of the provincial objective of a low carbon transportation network.

Currently, there are eight Level 3 DC fast-charging stations installed in FBC's electric service territory, with another twenty planned for installation between 2018 and 2019. Incremental funding is required to support the operation of the EV stations. Achieving these plans will depend in part on the outcome of an EV Charging Service Inquiry currently being conducted by the BCUC.

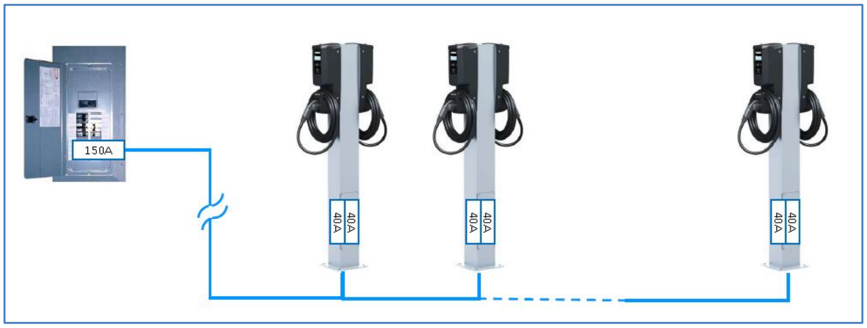
Following is discussion of some RD&D opportunities to support the development of the EV charging infrastructure in B.C.

1.8 *DYNAMIC LOAD CONTROL RESEARCH - RD&D STAGE*

FBC is interested in researching the use of dynamic load control systems to manage multiple Level 2 charging stations, and reduce overall installation costs by allowing multiple stations to use a single electric circuit.

[1] Electric Vehicle Fast Charging Infrastructure. TIPS Lab, University of British Columbia. May 2014

Figure A:C6-4-1: Dynamic Load Control Systems



1.9 *RETURN TO BASE CHARGING SOLUTIONS PILOT - RD&D STAGE*

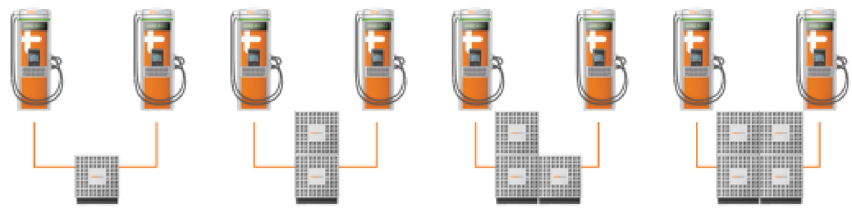
FBC is interested in piloting commercial vehicle/return to base charging solutions. There is currently considerable interest in fleet electrification opportunities. FBC is seeking opportunities to participate in future pilots of return-to-base charging infrastructure, including any transit-related opportunities.

Figure A:C6-4-2: Base Charging Solutions

1.10 *INNOVATIVE DCFC ARCHITECTURES PILOT - RD&D STAGE*

FBC is also interested in piloting DC Fast Charging installations with a modular design to allow increases in station capacity to accommodate increases in vehicle charging rates, as well as alternate station architectures for DC fast charging (e.g., central rectification for multiple charging ports).

Figure A:C6-4-3: DC Fast Charging



Example Configurations	A	B	C	D
Maximum power/port (kW)	125	250	375	500
Simultaneous power/port (kW)	62.5	125	187	250

1.11 *DEVELOPING DIGITAL NATURAL GAS FEEDSTOCK [TRL-4 TO TRL-8]*

FEI wants to gain a better understanding of 'Digital Feedstock' and, in particular, the barriers to broad-based adoption of digital feedstock as a basis for natural gas trading.

Digital Feedstock refers to a collection of technologies and practices that would allow for more diverse, granular and verifiable measurements of natural gas characteristics and the subsequent facilitation of a market for these characteristics. This would allow natural gas, which is currently highly commodified, in the sense of being treated the same across producers, to be a more differentiated product. Currently, there is only one characteristic of natural gas that is measured and traded: energy content (in MMBtu or GJ). However, natural gas produced by different plants can vary on a number of other dimensions that customers might care about. A primary one is the GHG content of a given unit of natural gas, which can vary both from the natural properties of gas in specific locations as well as from the energy-intensity and energy-efficiency of the plant that produces the gas. Buyers of natural gas including industrial users, residential consumers, and investors may well care about the GHG content and be willing to pay higher prices for 'cleaner' gas. Another as-yet untraded characteristic that varies across producers is the ethane content of natural gas, which can affect the Wobbe index and may be important information for transmitters and industrial users whose equipment may be affected.

Allowing for trading on these additional dimensions first requires data collection at the plant level. It then also requires a trading platform, possibly enabled by secure private or public ledger technology such as blockchain that can capture, verify, and disseminate this additional data about each unit of gas supplied to the market. Finally, it requires market participants to be willing to adopt or participate in this enhanced platform-based marketplace.

RD&D investments in this technology will be focused on implementing demonstrations projects that would demonstrate to stakeholders, gas producers and gas purchasers how well the technology works and allow better assessment of the business and environmental benefits.

1.12 *REDUCING FUGITIVE EMISSIONS [TRL-4 TO TRL-6]*

According to the BC Ministry of Environment[2], emissions in the energy sector come from three main energy sub-sectors: 1) stationary combustion sources such as boilers, turbines, engines, heaters; 2) transport such as road vehicles and marine and jet engines; and 3) fugitive emissions. Fugitive emissions are defined as "unintentional emissions from the processing, transmission and storage of fossil fuels."

With its large network of distribution and transmission pipeline used for transporting natural gas throughout the province to customers, FEI has undertaken a number of initiatives to reduce the level of fugitive methane emissions from its system. The activities include:

- Perform leak detection and repair at compressor stations;
- Develop a fugitive emissions management plan for LNG;
- Supporting BC One Call and "Call Before You Dig" to reduce the number of third party line hits and reduce the amount of potential escaped gas from punctured pipe;
- Conduct pipe surveys (i.e., aerial infrared inspection of transmission line to identify leaks, distribution line regular inspection); and
- Inline inspection (i.e., pigging) of transmission pipeline.

Reducing fugitive methane emissions can also be accomplished by improving reporting methods. For example, FEI has over a million gas meter sets in the Province where there may be fugitive emissions that are not measured with readings. Instead, FEI uses an industry factor to estimate the methane loss from the meter sets. Improvement in reporting methods can help to understand where fugitive emissions are occurring and where opportunities exist to reduce emissions.

In this area, FEI has taken steps to improve its fugitive methane emissions reporting including:

- Update to the residential meter set fugitive emission factor;
- Update to the industrial meter set fugitive emission factor;
- Update to the buried pipe fugitive emission factor; and
- Development of a FEI emission factor based on design for gate stations.

In addition to its existing activities, FEI is evaluating RD&D activities to help reduce fugitive methane emission. With the innovation funding, FEI intends to invest in an optical gas imaging device, investigate welding options for residential meter sets, use new methane technology on vehicles to increase the frequency of leak detection on distribution pipelines, pursue

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[2] BC Environmental Reporting government website - http://www.env.gov.bc.ca/soe/indicators/sustainability/ghg-emissions.html

decommissioning of high bleed pneumatic devices and conduct additional studies looking to improve our estimates on GHG emissions.

1.13 *NGIF [TRL-2 TO TRL-8]*

FEI is a founding member of the Canadian Gas Association's Natural Gas Innovation Fund (NGIF).

NGIF partners include natural gas utilities in Canada, provincial entities, as well as upstream partners such as pipelines and natural gas production. With respect to utility-like projects, NGIF invests in technologies such as carbon capture, energy efficiency, heat and power generation, intelligent systems, methane capture, natural gas generation including RNG, and H2 production.

NGIF will be a vehicle for FEI to invest in innovation and leverage participation by other utilities. The NGIF provides the benefit of coordinating innovative technology RD&D across all Canadian utilities to minimize duplication of effort and leverage the funding of the utilities participating. This enables FEI to focus its other RD&D activities of benefit to its customers to address challenges and opportunities unique to B.C. or that would remain otherwise undeveloped.

For FEI, funding required will depend on available pilot opportunities.

Appendix C7

FBC POWER SUPPLY INCENTIVE

FBC POWER SUPPLY INCENTIVE

1. INTRODUCTION

In this Appendix, FortisBC Inc. (FBC or the Company) proposes a Power Supply Incentive (PSI) to encourage FBC to increase efficiency, reduce costs, and enhance performance in the area of power supply, over and above what is reasonably expected in the normal stewardship of FBC's business.

As described in FBC's Long-Term Electric Resource Plan (LTERP), FBC currently has sufficient resources to meet its annual energy requirements and peak demand forecast through 2024.[1] These resources, which are described in Section 2.1 of this Appendix, provide a reliable and secure supply to meet FBC load requirements. These resources also represent a significant cost to FBC's customers. For example, in 2019 FBC's power supply portfolio, which includes Power Purchase Expense (PPE), wheeling and water fees, is forecast at $161 million, which is equal to 43 percent of the Company's 2019 revenue requirement.[2]

FBC has opportunities to reduce PPE by accessing the wholesale electricity markets and displacing its higher cost contractual power purchases with cheaper market purchases, and selling surplus capacity through active portfolio optimization. The wholesale electricity marketplace, however, is complex and dynamic. As a result, recognizing and taking advantage of opportunities to mitigate power purchase costs requires vigilance in monitoring developments, and having policies and strategies in place to create value when opportunities arise. FBC must also ensure that these activities do not compromise security or reliability of supply for customers.

As discussed in Section 1.1 of this Appendix, over the past twenty years, the BCUC has at times approved incentive mechanisms that support FBC's efforts to mitigate PPE for the benefit of customers. An incentive program further aligns the interests of the utility and its employees, who are responsible for maximizing this mitigation benefit, with the interests of customers, who benefits from the lower net power costs. Other benefits of incentive mechanisms include the following:

- they can encourage utilities to maintain, or improve, relevant performance areas;
- they allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes; and

[1] See FortisBC Inc.'s 2016 Long Term Electric Resource Plan and Long Term Demand Side Management Plan, Decision pages 14,15 and Order G-117-18,
[2] Forecast Power Purchase Expense 2019, Annual Review for 2019 Rates, Page 33

- they provide utilities with greater incentives to achieve desired outcomes and tie utilities' profits more to performance than to capital investments.[3]

FBC is therefore requesting approval of a PSI to encourage the Company to increase efficiency, reduce costs, and enhance performance in the area of power supply. As discussed in Section 1.2, the proposed PSI is based on sound objectives and guiding principles as previously articulated by the BCUC.

As explained in Section 3.1 of this Appendix, FBC's proposed PSI will determine the reduction in PPE achieved by FBC's optimization activities, which is referred to as the Eligible Mitigation Benefit, and will create a Benefit Sharing Mechanism to apportion the benefits reasonably between customers and the Company. As described in Section 3.2 of this Appendix, FBC is proposing that the first $7.5 million of any reduction in PPE as a result of optimization activity will be to the benefit of customers, with the remaining reduction apportioned 90 percent to customers and 10 percent to the Company.

FBC believes that the PSI will result in savings for customers over and above what would otherwise be achieved, and respectfully requests approval of the PSI for the term of the MRP.

1.1 *REGULATORY HISTORY OF FBC'S PPE INCENTIVES*

The BCUC has approved various sharing mechanisms for variances between forecast and actual PPE over time. This section provides a review of these sharing mechanisms and the treatment of variances in PPE since 1996.

- From 1996 to 1998[4], FBC received all of the benefit of market opportunities that were not included at the time of rate setting.
- In 1999[5], a power purchase incentive mechanism, called the Market Incentive Mechanism (MIM), was introduced in response to customer concerns. The MIM shared benefits arising from displacing BC Hydro supply with market purchases. FBC's share was all of the first $0.2 million, 50 percent of the next $0.4 million, and 25 percent of amounts over $0.6 million. FBC's share was capped at $0.5 million.
- From 2000[6] to 2005, the MIM continued with slight changes. FBC's share was 35 percent of the first $1.0 million and 25 percent of amounts over $1.0 with no cap.
- In 2006[7], no incentive mechanism was in place. 100 percent of the PPE variance was flowed through to the customers.

[3] Appendix C8, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*.
[4] WKP Revenue Requirements Negotiated Settlement, Order G-73-96
[5] Preliminary 1999 Revenue Requirements and Incentive Mechanism Review Application, Order G-123-98
[6] Revenue Requirements 2000-2002 and Incentive Mechanism Review, Order G-134-99

- Under the 2007 to 2011 PBR[8], the PPE variance was shared 50 percent to customers and 50 percent to the Company through the ROE sharing mechanism applicable during the period.
- From 2012 to 2013[9], no incentive mechanism was in place and 100 percent of the PPE variances, positive or negative, were again flowed through to customers.
- The 2014-2019 PBR Plan[10] continued to treat all variances in PPE, including those due to optimization activities, as a flow through, with all variances to the account of customers.

FBC believes that returning to a sharing mechanism will encourage the Company to increase efficiency, reduce costs, and enhance performance with respect to its power supply portfolio management, and the proposed PSI creates a reasonable and transparent incentive that will work well under varying and dynamic market conditions.

1.2 *OBJECTIVES AND GUIDING PRINCIPLES OF THE PSI*

The objectives of FBC's proposed PSI are as follows:

1. **Alignment of Interests**: The PSI should encourage FBC to optimize resource use within its portfolio, and create significant benefits to the customer in doing so.
2. **Supply security**: The PSI should discourage any activity that might adversely affect the security of supply or total PPE.
3. **Fair and Reasonable Incentives**: The PSI should be structured to encourage optimization activities and reward substantial exertions by the Company.
4. **Simplicity**: The PSI should be structured in such a way that it minimizes administrative effort in the context of the other three objectives.

FBC's proposed PSI satisfies the four objectives above. By implementing the PSI, the interests of customers and the Company will become further aligned. FBC's customers can gain increased certainty that FBC is undertaking all reasonable measures to reduce PPE, and that FBC is continuing to ensure that the appropriate resources are in place in order to manage PPE effectively, while continuing to pursue overall productivity gains within the Company. Furthermore, the PSI will encourage FBC to seek out new mitigation activities in an attempt to

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7 An Application by FortisBC Inc. for Approval of 2005 Revenue Requirements, 2005-2024 System Development Plan and 2005 Resource Plan, Order G-52-05

8 2006 Revenue Requirements Application, Order G-58-06

9 An Application by FortisBC Inc. for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan, Order G-110-12

10 Multi-Year Performance Based Ratemaking Plan for 2014 through 2018, Order G-139-14

increase the optimization benefit, while continuing to ensure security of supply. FBC believes that the proposed PSI strikes the necessary balance such that these objectives will be met.

In 2011, in Order G-26-11, the BCUC identified eight Guiding Principles to help develop an incentive plan for FortisBC Energy Inc. FBC believes that these principles are appropriate to consider in the development of the PSI. The following table shows the principles and how they relate to FBC's PSI.

Table C7-1: BCUC Guiding Principles in Relation to FBC's PSI

Order G-26-11 Guiding Principles	FBC PSI
1. The incentive program must demonstratively deliver value to ratepayers and reward ongoing innovation and true value added over and above what is reasonably expected in the normal stewardship of TGI's business.	FBC's optimization activities deliver significant value to FBC customers. The PSI will incent FBC to increase value over and above what is otherwise expected by providing sharing of benefits above the first $7.5 million of any reduction in PPE.
2. Execution of the incentive program must not put the prudently planned gas supply portfolio at risk nor promote a departure from prudent gas supply management for core customer's requirements.	The PSI does not encourage activities that would increase power supply risks. FBC will continue to file an Annual Electric Contracting Plan to meet customer demand and optimize its portfolio in the short-term as discussed in Section 3.4.
3. The incentive plan should fairly and appropriately align ratepayer and shareholder interests.	The Benefit Sharing Mechanism under the PSI ensures that the ratepayer and shareholder interests are aligned, as the Company and the customer will share in the value added by FBC above the first $7.5 million of any reduction in PPE.
4. There should not be an upper limit on TGI's potential to earn an incentive but there must be a test of reasonableness and the amount earned must be justified.	The PSI does not have an upper limit. The proposed Company share of 10 percent above the first $7.5 million of any reduction in PPE is reasonable and justified given the significant value added to ratepayers.
5. The incentive program should apply to all mitigation activities that use commodity supply resources that represent a cost and risk to ratepayers (i.e. gas supply, storage, transportation).	The PSI fully encompasses all FBC's power supply resources that represent a cost and risk to FBC's customers as discussed in Section 2.
6. The incentive plan should reward TGI for its innovation rather than for opportunities that arise from events that impact the industry in general (e.g. hurricanes).	Under the PSI, FBC is incented to seek innovation and increase PPE mitigation beyond general industry events, as there is no sharing on the first $7.5 million of any reduction in PPE.
7. Any incremental administrative costs must be considered and charged against the benefits of the plan.	FBC will deduct any incremental administration costs from the plan as discussed in Section 3.1.
8. The incentive payment should be the smallest amount required to obtain the desired core customer benefit.	The sharing under the proposed PSI is 10 percent of savings above the first $7.5 million of any reduction in PPE. FBC considers this to be the minimal amount required to provide an incentive to the Company to achieve value over and above what would otherwise be expected.

2. OVERVIEW OF POWER SUPPLY RESOURCES AND OPTIMIZATION ACTIVITIES

2.1 *FBC SUPPLY-SIDE RESOURCES AND RELATED AGREEMENTS*

FBC uses a combination of Company-owned generation entitlements, firm contracted supply and market purchases to meet its load requirements. The Company's firm resources consist of:

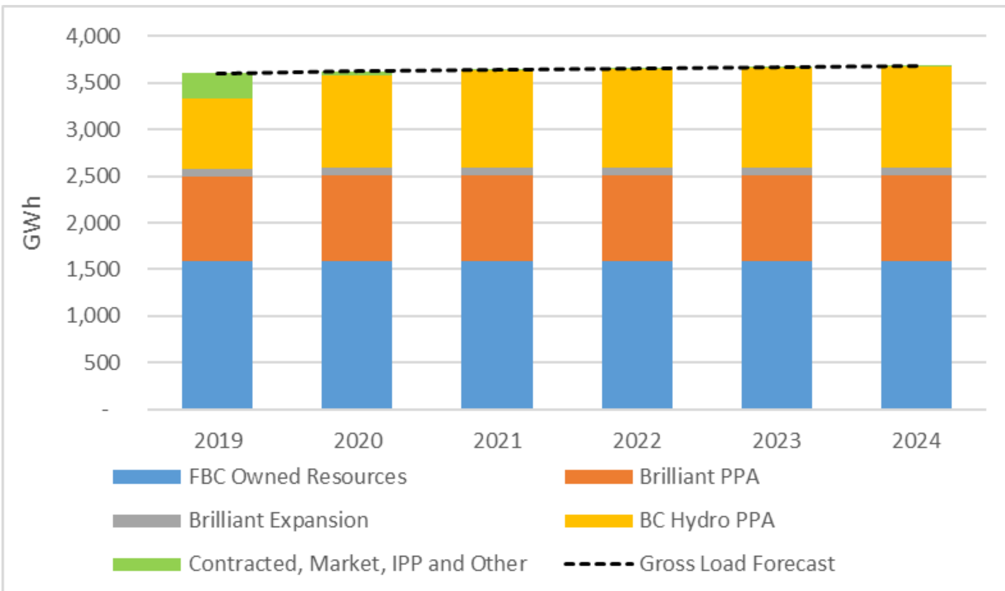
1. Canal Plant Agreement (CPA) entitlements associated with the generation facilities owned by FBC.
2. The Brilliant Power Purchase Agreement (BPPA), a 125 MW contract (Order E-7-96), and an amendment to the BPPA which reflects the purchase of 20 MW of Brilliant Upgrade power (Letter L-57-00) and the 5 MW Brilliant Tailrace Capacity agreement (Order E-17-01);
3. An agreement with the Columbia Power Corporation and the Brilliant Expansion Power Corporation (Order E-17-17) for an average of 33 MW;
4. A power purchase agreement (PPA) with BC Hydro (a 200 MW contract) under BC Hydro Rate Schedule 3808 (RS 3808) (Order G-60-14);
5. The Waneta Expansion Capacity Purchase Agreement (WAX CAPA), which is a 40-year purchase agreement with the Waneta Expansion Limited Partnership for capacity entitlements under the CPA (Orders E-29-10 and E-15-12);
6. The Residual Capacity Agreement (RCA) with BC Hydro which is a ten-year agreement for FBC to sell to BC Hydro 50 MW of capacity that FBC has purchased under the WAX CAPA (Order G-161-14).
7. The Capacity and Energy Purchase and Sale Agreement (CEPSA) (February 17, 2015) (Order E-10-15) between Powerex and FBC, whereby FBC purchases all of its market energy requirements from Powerex and sells any surplus capacity that may be available after meeting its load requirements to Powerex, in each case at market based prices. The CEPSA can expire as early as September 30, 2020 but can be extended through 2025 on an annual basis upon mutual agreement of the parties.
8. A number of small Independent Power Producer (IPP) contracts.
9. A number of energy supply contracts completed under the CEPSA, and approved by the BCUC.

Over the past few years, FBC has undergone significant changes to its portfolio and related agreements, including a new PPA with BC Hydro and associated agreements becoming effective July 1, 2014, the addition of WAX CAPA to the portfolio on April 2, 2015, and the implementation of the CEPSA on May 1, 2015 with Powerex. FBC expects that there will be no major changes to its supply-side resources and related agreements through 2024 as as discussed in the Company's most recently filed LTERP, aside from the potential expiration of the CEPSA, which will have no impact on the calculation of the Eligible Mitigation Benefit or Benefit Sharing Mechanism (see Section 3 below). The PSI will also ensure that the interests of the Company and the customer are aligned for any potential renewal, or lack thereof, of the current CEPSA.

2.2 *FBC POWER SUPPLY OPTIMIZATION ACTIVITIES*

At this time, the Company currently has long-term firm resources that can supply all of its forecast annual energy and capacity requirements. Figure A:C7-1 below shows how FBC's long-term firm resources will be used to supply its forecast gross load for 2019 through 2024.

Figure C7-1: 2019 - 2024 FBC Gross Load and Energy Resources (GWh)



The Company can mitigate its PPE using several different methods:

1. PPA Energy Displacements:

   FBC can displace energy under the BC Hydro PPA using lower priced long-term forward and real-time market purchases. The BC Hydro PPA provides the Company with flexibility to participate in the market when conditions are favourable. In order to maximize value by using the wholesale market, ongoing and substantial diligence, effort, and support from the Company is required. Because some energy purchases are made to also displace PPA capacity, they can also result in PPA capacity savings.

2. PPA Capacity Displacements:

   FBC can also displace capacity under the BC Hydro PPA using lower priced long-term forward and real-time market purchases. The amount of PPA Capacity paid by FBC in any given month is the greater of the amount used in the month, 75% of the peak demand in the previous 11 months, and 50% of the Contract Demand of 200 MW. By using market purchases to avoid PPA capacity purchases, FBC can create mitigation benefit in the current month, and also in the subsequent months. Savings can arise from any of these three factors, each discussed separately below:

a. PPA Capacity Required for Energy

If FBC did not rely on market energy, in many cases it would have to increase its PPA capacity take in order to bring in sufficient energy under the PPA, thereby increasing the capacity monthly billing amount.

b. PPA Capacity Required to meet Peak Demand

FBC further avoids PPA capacity purchases by purchasing market energy on peak hours, reducing peak demand requirements.

c. PPA Capacity Ratchet Savings

If FBC were to purchase all of its peak demand requirements from the PPA, it would create higher PPA billing demand in that month, and FBC would be required to pay a minimum PPA take of 75 percent of that new peak billing demand over the next 11 months. For example, if FBC took 200 MW of PPA capacity in a month, the minimum billing amount for the subsequent eleven months would be 150 MW. FBC would not be able to reduce the PPA billing demand below 150 MW during the eleven-month period, which would limit the potential mitigation benefit that can be achieved.

The total value of PPA capacity displacements is calculated based on the highest amount of PPA that would have been required in each month for either energy requirements, to meet peak demand, or due to the PPA capacity billing ratchet, and comparing that to the actual PPA billing capacity in that month.

3. Surplus Sales:

The Company can also mitigate its PPE by releasing surplus WAX capacity on a day-ahead basis to Powerex under the CEPSA agreement. FBC is required to pay for all of the available capacity under the WAX CAPA, but has the ability to sell surplus capacity when it is not being used to meet FBC load.

Additionally, rather than just releasing any remaining unused capacity to Powerex under the CEPSA, FBC may optimize its hourly resources such that it creates additional surplus capacity that can be sold under that agreement. By using methods like purchasing additional spot market power or increasing hourly PPA purchases, FBC can increase its volume of capacity released under the CEPSA when market conditions are favorable to do so.

There is a high degree of complexity in the pricing and use of these resources, and optimizing the combination of resources is one way that FBC mitigates PPE. All of these activities are linked, and the optimal balance between them is adjusted on an hourly basis. It requires a significant level of effort to produce the best results.

3. POWER SUPPLY INCENTIVE BENEFIT SHARING PLAN

3.1 *CALCULATION OF ELIGIBLE MITIGATION BENEFIT*

An essential requirement of the PSI is to provide a transparent methodology for reviewing FBC's performance that works well under dynamic and varying market conditions. The calculation of the Eligible Mitigation Benefit is the starting point for this methodology, as it determines the total value that will be eligible for sharing between the Company and customers. The Eligible Mitigation Benefit is as follows:

- **Calculation of the Eligible Mitigation Benefit:** The Eligible Mitigation Benefit will calculate the value added by FBC as a result of its PPE optimization activities using "Eligible Resources", net of "Incremental Costs". The Eligible Mitigation Benefit will be determined by comparing FBC's actual cost of supply to FBC's cost of supply if FBC did not undertake any optimization activities with its Eligible Resources, including executing market purchases and selling surplus capacity, less any Incremental Costs. In other words, the Eligible Mitigation Benefit will be calculated by comparing FBC's actual PPE to the calculated PPE under a passive strategy in which FBC did not engage in any active optimization activity, and solely relied on its firm contracted resources to meet load.[11] FBC is not suggesting that the passive strategy is something that would occur in absence of the PSI; rather, FBC is using the calculated passive strategy PPE as a floor from which to calculate Eligible Mitigation Benefit. The calculation of the Eligible Mitigation Benefit will be based on actual load data as determined after the fact, thus removing any reductions that would have occurred only due to reduced load, and limiting the Eligible Mitigation Benefit only to savings achieved as a result of FBC's optimization activities using Eligible Resources.
- **Eligible Resources:** All market contracts and surplus sales that are less than five years in term will be considered Eligible Resources and included in the calculation of Eligible Mitigation Benefit. Eligible Resources include wholesale market arrangements and surplus sales, including any revenue under the CEPSA with Powerex, or successor agreement. FBC's wholesale market purchases already in place would be included in the Eligible Mitigation Benefit as they require active monitoring and optimization in order to ensure the maximum benefit is achieved.

[11] The Eligible Mitigation Benefit will not be calculated by comparing actual to the forecast PPE for rate setting purposes. When forecasting PPE for rate setting, use of the various resources is based on forecast load and not all market purchases for the year have been executed. The Eligible Mitigation Benefit takes actual load into account, along with all mitigation activities over the course of the year.

- **Incremental Costs:** To create the PPE mitigation, FBC may incur additional costs, such as the cost of short-term wheeling reservations from BC Hydro, wheeling costs on Teck Metal's Ltd. 71 Line and/or additional market research information from third parties. The value of Eligible Mitigation Benefit for which FBC receives an incentive is the market savings net of these Incremental Costs. At this time, the only Incremental Costs will be short-term wheeling reservations from BC Hydro and wheeling costs on 71 Line, which will be included as an offset to the Eligible Mitigation Benefit.

As described above, the calculation of Eligible Mitigation Benefit fully accounts for FBC's current optimization activities. As indicated in Section 1.1, one of the objectives of the PSI is to encourage FBC to seek out additional new optimization activities. Should FBC engage in any new optimization activities, they would be included in the calculation of Eligible Mitigation Benefit provided they meet the definition of Eligible Resources as described above. The detailed calculation and description of the activities will be included in FBC's annual reporting to the BCUC, as discussed in Section 3.3 below.

Additionally, should FBC engage in any new activities or expand existing activities that require a material increase in administration costs, the costs will be included as an offset to Eligible Mitigation Benefit.

3.2 *CALCULATION OF THE BENEFIT SHARING MECHANISM*

The Benefit Sharing Mechanism should ensure that the optimization activities undertaken by the Company provide significant value to FBC's customers, a reasonable benefit to the Company, and are adequate to meet the objectives of the PSI as discussed in Section 1.2 above.

FBC recommends that the sharing mechanism should allocate the first $7.5 million in benefits to customers, and allocate any benefit beyond that with 90 percent going to the customer and 10 percent to the Company.

This provides FBC with a framework that will ensure that the customer receives the majority of the mitigation benefits, while rewarding FBC for the value added above what is reasonably expected in the normal course of business. FBC will be incented to focus on core optimization activities and to be innovative in looking at new optimization opportunities that meet the objectives of the PSI.

3.3 *PSI REPORTING*

Within 60 days of the end of each year, FBC will submit a confidential report to the BCUC, with notice to interveners, outlining its calculation of total Eligible Mitigation Benefit and the calculation of the Benefit Sharing Mechanism, as well as a summary of market conditions, optimization activities and any security of supply issues completed during the year. This will include any new optimization activities.

FBC will include a forecast of the incentive in its annual review applications; the final Benefit Sharing Mechanism amount will be trued up in the subsequent year. Also, the Benefit Sharing Mechanism and the PSI will be calculated as part of Targeted Incentives (see Section C8.2.7), separate from the earnings sharing mechanism of FBC's MRP.

This reporting mechanism will provide the BCUC with a means of overseeing FBC's power supply optimization activities by enabling the BCUC to review relevant information and to measure performance.

3.4 RELATION TO THE AECP AND REVENUE REQUIREMENT APPLICATIONS

The existence of the PSI will not result in any changes in FBC's PPE forecasting, AECP processes or its filing of Energy Supply Contracts. FBC will continue to file an AECP to outline FBC's plan for optimizing its portfolio in the short-term and FBC's proposed Annual Energy Nomination under the BC Hydro PPA, highlighting any new optimization activities that FBC will be undertaking. FBC will continue to forecast all current PPE mitigation in its regular forecast of PPE as part of annual rate setting (and may include other anticipated optimization activity for rate setting, as appropriate).

3.5 CONCLUSION

FBC's power supply portfolio represents is a significant component of FBC's revenue requirement, and requires a significant effort to optimize. The proposed PSI will encourage the Company to increase efficiency, reduce costs, and enhance performance in power supply. The PSI has been designed to ensure the objectives, as detailed in Section 1.2 above, are met, including:

1. **Alignment of Interests**: The plan encourages FBC to optimize its portfolio, and creates significant benefits to the customer in doing so. The plan will ensure FBC continues to dedicate appropriate resources to the management of the power supply portfolio, while continuing to look for overall productivity gains in the Company.
2. **Supply security**: The plan discourages any activity that might adversely affect the security of supply or total PPE.
3. **Fair and Reasonable Incentives**: The plan is structured to encourage optimization activities and to reward new substantial exertions by the Company. The PSI results in a reasonable benefit to the Company while obtaining the desired customer benefit.
4. **Simplicity**: The plan is structured in such a way that it minimizes administrative effort, including allowing the BCUC and interveners to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.

The PSI represents an evolution of FBC's long history with power purchase incentives, and creates a reasonable and transparent incentive that will work well under varying and dynamic market conditions.

Appendix C8

UTILITY PERFORMANCE INCENTIVE MECHANISMS

Utility Performance Incentive Mechanisms

A Handbook for Regulators

Prepared for the Western Interstate Energy Board

March 9, 2015

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The views presented in this report are those of the authors and do not necessarily represent those of the project management team or reviewers. All errors are our own.

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EXECUTIVE SUMMARY

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms. Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources.

Whether performance incentive mechanisms are added onto traditional ratemaking practices, included as part of performance-based regulation (PBR) plans, or considered as a central element of new regulatory and utility business models, they can be used to help improve utility performance. As with all regulatory mechanisms, they should be designed thoughtfully and they should build off of lessons learned from past practices.

Advantages of Performance Incentives

Utility performance metrics and incentives can serve as a valuable tool for regulators for various reasons:

- They help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized, or well understood.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals. In the absence of performance metrics and incentives, utilities have little incentive or guidance for achieving policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

Potential Pitfalls of Performance Incentive Mechanisms

As with all regulatory mechanisms, the success of performance incentive mechanisms is very much dependent upon their design and implementation. Experience to date has shown that there are many potential pitfalls that regulators should be aware of:

> Disproportionate rewards (or penalties). Performance incentive mechanisms can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.
>
> Unintended consequences. Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.
>
> Regulatory burden. Performance incentive mechanisms can be costly, time-consuming, or a distraction from more important activities for all parties involved. If this burden becomes too great, it can undermine the value of performance incentive mechanisms.
>
> Uncertainty. Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. In addition, significant and frequent changes to performance incentive mechanisms create uncertainty for utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.
>
> Gaming and manipulation. Every performance incentive mechanism carries the risk that utilities will game the system or manipulate results.

In most cases, these pitfalls can be managed through sound design and implementation of performance metrics and incentives. They can also be mitigated by ongoing evaluation of and improvements to the incentive mechanisms. Chapter 6 presents a more detailed discussion of these pitfalls and recommendations for how to avoid them.

Performance Incentives Can Be Used in Any Regulatory Context

One of the advantages of performance metrics and incentives is that they can be used in any regulatory context. However, it is critical that performance metrics and incentives be specifically tailored to the existing (or anticipated) regulatory context in each state, to ensure that they adequately complement and balance the financial incentives provided by that regulatory context.

> In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance; to address areas

where regulators see opportunities for greater efficiencies or reduced costs; and to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.

In a state with performance-based regulation, performance metrics and incentives might be especially important to prevent the degradation of service as a result of pressures to reduce costs, and to complement the existing regulatory incentives, such as those provided by price (or revenue) caps, fixed periods between rate cases, and cost trackers.

In a state developing new regulatory and utility models, performance metrics and incentives might be especially important to re-direct utility management priorities toward desired performance outcomes, and shift the source of utility revenues away from capital investments and toward those desired outcomes.

In any state, performance metrics and incentives can be used to promote resources that are not supported or encouraged by the existing regulatory system, such as energy efficiency and renewable resources.

In any state, performance metrics and incentives can be used to provide guidance on how utilities can meet state regulatory policy goals, such as improving reliability and resiliency, empowering customers to reduce bills, or minimizing the cost of complying with the EPA Clean Power Plan.

In any state, performance metrics and incentives can be used to encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the existing regulatory system, such as distributed generation, grid modernization, storage technologies, or practices to support electric vehicles.

Key Principles and Recommendations

Based on our review of the literature and the lessons learned from various jurisdictions, we provide numerous recommendations and principles for designing effective performance metrics and incentive mechanisms. These are summarized in the table below.

Table 1. Key Principles and Recommendations

Regulatory Contexts **(Chapter 2)**	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics **(Chapter 3)**	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets **(Chapter 4)**	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties **(Chapter 5)**	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

Questions for Regulators

Regulators may wish to ask several questions to help inform their decisions on whether and how to proceed with performance metrics and incentives:

- How well does the existing regulatory framework support utility performance?
- How well does the existing regulatory framework support state energy goals?
- What are the policy options available to improve utility performance?
- Are industry, technology, customer, or market conditions expected to change?
- Does the commission wish to articulate specific, desired performance outcomes? If so, in what performance areas?
- Does the commission prefer to oversee utility expenses and investments after the fact (e.g., through rate cases and prudence reviews), or to guide performance outcomes before investments are made?

Implementation Steps

Once a determination has been made to implement performance metrics or incentive mechanisms, the following steps can be implemented. These can be implemented incrementally to allow for each step to inform the subsequent step, or they can be implemented all at once.

1. Articulate goals**.** The first step is to identify and articulate regulatory policy goals. These goals should help inform choices of performance areas, targets, and penalties.
2. Assess current incentives**.** Next it is critical to understand the financial incentives created by the current or anticipated regulatory context.
3. Identify performance areas that warrant performance metrics**.** Performance metrics may be warranted for traditional performance areas or new and emerging areas.
4. Establish performance metric reporting requirements**.** Review performance reports to monitor those areas identified above, to identify any performance areas that may require targets.
5. Establish performance targets, as needed**.** Establish targets to provide utilities with clear messages regarding the level of performance expected by regulators. Review results to determine whether any performance areas warrant rewards or penalties.
6. Establish penalties and rewards, as needed. Establish rewards or penalties to provide direct financial incentives for maintaining or improving performance.
7. Evaluate, improve, repeat. The effectiveness of the mechanisms should be monitored and evaluated on a regular basis to determine whether there is a need for improvement.

1. INTRODUCTION

Purpose and Overview

This report describes how regulators can guide utility performance through the use of performance incentive mechanisms (sometimes abbreviated here as PIMs). Regulators have used these mechanisms for many years to address traditional performance areas such as reliability, safety, and energy efficiency. In recent years, these mechanisms have also received increased attention due to regulatory concerns over resilience, utilities' ability to respond to technological change, and the expanding opportunities for distributed energy resources. The ultimate objective of performance metrics and incentives is to better align utility regulatory and financial incentives with the public interest.

In the following chapters, we identify many of the metrics and performance incentives that regulators have used to monitor and evaluate utility performance, as well as emerging metrics and incentives that are being discussed in jurisdictions facing new issues and challenges, such as integration of renewable and distributed energy resources.[1] We provide a set of principles and recommendations for regulators, based on our review of the large amount of literature on these topics and the lessons learned from the case studies that we reviewed. Our research is primarily focused on electric utilities, but we have included some metrics specific to natural gas utilities as well.

This handbook builds off of a Western Interstate Energy Board report titled *New Regulatory Models* (Aggarwal and Burgess 2014).[2] That report provides a number of examples of how performance standards have been used by regulators.

Industry Changes and Pressures

Traditional cost-of-service regulation was originally designed in an era of significantly increasing sales and decreasing marginal costs, where the primary decisions required by utilities were related to how much and what type of generation and transmission to build to meet growing customer demand, and where the main goal was to ensure just and reasonable rates. The conditions currently facing the utility industry have changed considerably, for instance:

- Retail sales are increasing at much lower levels than in the past, and some utilities are experiencing declining sales. Sales may drop even further as customers adopt more demand-side measures, especially energy efficiency, distributed generation, and storage technologies.

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[1] In fact, even where utility commissions have not implemented specific utility standards, utilities already comply with a variety of industry standards set by organizations such as the Institute of Electrical and Electronics Engineers (IEEE), the Occupational Safety and Health Administration (OSHA), the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), the Financial Accounting Standards Board, and the Environmental Protection Agency (EPA).

[2] The Phase I report is available here: http://westernenergyboard.org/wp-content/uploads/2014/03/SPSC-CREPC_NewRegulatoryModels.pdf

On the other hand, electric vehicles and other forms of electrification could lead to increased sales.

- Many utilities are facing the need to replace aging infrastructure, which may require significant capital investments that will not necessarily lead to reduced costs or increased sales.
- Utilities have many more options to choose from, in terms of generation, transmission, and distribution technologies, as well as more ways to address customer needs through resources on the customer side of the meter (including energy efficiency, demand response, distributed generation, automated metering technologies, and customer-facing smart grid options).
- Regulators have established a variety of public policy goals beyond simply maintaining just and reasonable rates. These include goals related to consumer protection, promoting competitive markets, encouraging and implementing demand-side resources, encouraging and implementing renewable resources, improving responses to major outages, and meeting carbon and other environmental constraints.

Some states are finding that traditional cost-of-service regulation may not provide utilities with the financial incentives to respond effectively to all of these developments. In some cases, traditional regulatory practices may provide financial incentives that hinder utilities from addressing these challenges. Consequently, performance metrics and incentives may provide an opportunity to better align utility incentives with evolving regulatory goals and the public interest in general.

Performance Metrics and Incentive Mechanisms

In this report we focus on both performance incentive mechanisms that use financial rewards and penalties to encourage utilities to meet specific targets, as well as performance metrics for simply monitoring and reporting utility performance. The relationship between the steps to implement these regulatory tools is shown in Figure 1 below.

Figure 1. Performance Incentive Mechanisms vs. Performance Metrics

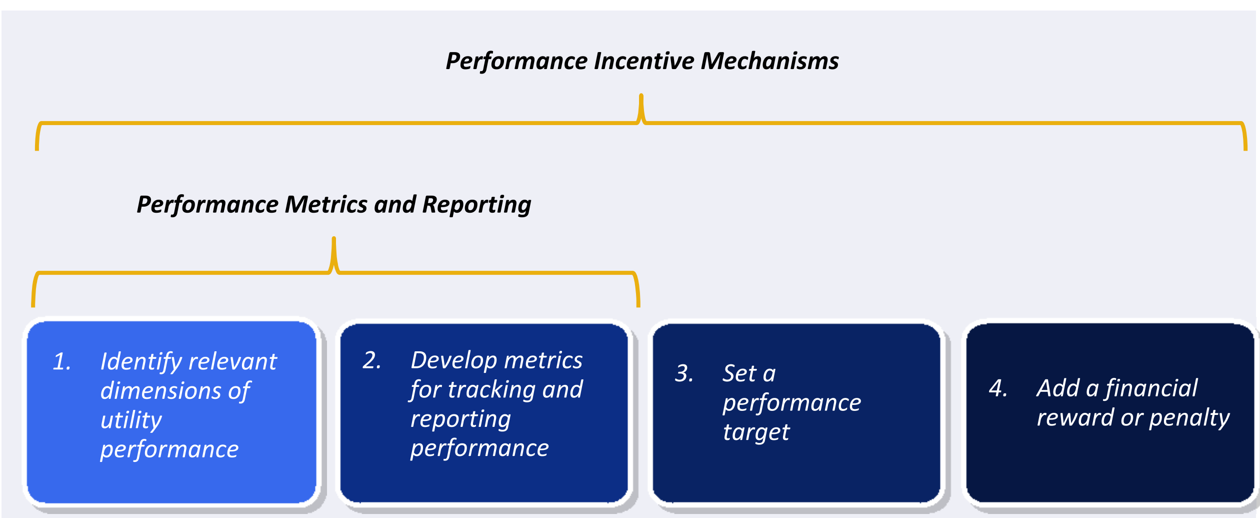

Figure 1 also highlights the various components involved in creating performance metrics and incentives.

These steps can be taken incrementally over time until the desired level of incentives is reached. First, performance metrics and reporting can be established to monitor utility performance. Second, specific performance targets can be set to provide a clear signal regarding the level of performance that is expected of a utility. Finally, financial rewards and penalties can be applied to increase the utility's motivation to achieve the performance targets. This incremental approach allows regulators and utilities to learn from each step before designing and implementing the next step. It also enables regulators to review utility performance without implementing financial rewards or penalties where such incentives are not necessary.

Alternatively, these four steps can be applied all at once, in the form of performance incentive mechanisms. This would be appropriate in those cases where regulators (a) have performance areas, metrics, and goals in mind, and (b) recognize the need for rewards and penalties.

Advantages of Performance Metrics and Incentive Mechanisms

Utility performance metrics and incentives can serve as a valuable tool for regulators for various reasons. For example:

- They help to make regulatory goals and incentives explicit. All regulatory models provide financial incentives that influence utility performance, but many such incentives are not always explicit, recognized, or well understood.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.
- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals. In the absence of performance metrics and incentives, utilities have little incentive or guidance for achieving policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

2. Regulatory Context

Evolving Regulatory Contexts

As Peter Bradford noted in the book *Regulatory Incentives for Demand-Side Management*: "All ratemaking is incentive ratemaking. It rewards some patterns of conduct and deters others" (Bradford 1992). In other words, every regulatory environment contains a variety of financial incentives that will affect utility performance. In designing performance metrics and incentive mechanisms, it is critical to first understand the incentives that existing under the existing regulatory environment.

There is currently a wide variety of regulatory systems across the United States, as each state has adopted different regulatory mechanisms over time to address its own needs. However, it is useful to discuss three categories of regulatory contexts for the purpose of describing how performance incentives might fit into each. These categories include: cost-of-service (COS) regulation, performance-based regulation (PBR), and new regulatory models. These regulatory contexts are summarized in Table 2 and discussed below.

It is important to emphasize that these three categories are simplistic, by design, relative to the many variations of regulatory elements in use today. Few states fall clearly into one category or another. The purpose of this table is simply to identify the key distinguishing features among these three frequently-discussed categories.

Table 2. Three Categories of Regulatory Systems

Regulatory Element	Cost of Service Regulation	Performance-Based Regulation	New Regulatory Models Proposed to Date
Basis for initial rates	Based on cost-of-service studies using a test year	Based on cost-of-service studies using a test year	Would likely be based on cost-of-service studies; may be influenced by utility business plans
Frequency of rate cases	Utilities apply for rate cases as needed or required, typically to recover large capital investments or revenue attrition	Pre-determined, fixed period of time (e.g., five years) to encourage efficient management and operations	Pre-determined, fixed period of time (e.g., eight years) to encourage efficient management and operations
Base rate adjustments between rate cases	Generally none	Price cap modified to account for factors such as inflation and productivity	Price cap may be modified to allow for inflation, productivity, or costs included in utility business plans
Cost trackers	Generally limited to costs beyond utility control	May include trackers for capital costs not easily accounted for in the price cap	Would likely include trackers for capital costs identified in utility business plans
Prudency reviews	Generally applied after the fact, where excessive costs become obvious	Applied after the fact, in cases where excessive costs become obvious	Applied after the fact; would likely be limited, based on utility business plans
Resource Planning	Option to include integrated resource planning	Option to include integrated resource planning	Strategic business plans would be used to inform cost trackers and adjustments between rate cases
Revenue regulation	Option to implement a decoupling mechanism	Option to include a revenue cap, instead of a price cap	Would likely include a revenue cap, instead of a price cap
Performance Incentive Mechanisms	Focus on areas of poor performance or opportunities for improvement	Focus on areas that may experience service degradation in response to pressure to reduce costs	Designed to create incentives to achieve a broad set of desired outcomes

Traditional Cost-Of-Service Regulation

Traditional cost-of-service regulation is characterized by the following elements:

1. Base rates are set in a rate case, typically based on known and measurable costs identified in a test year (historical, future, or a hybrid).

2. Frequency of rate cases, which typically occur at the request of the utility for the purpose of recovering major capital expenditures or addressing revenue attrition. Commissions generally have the authority to request that a utility file a rate case, but this rarely occurs in practice.

3. Base rates generally remain constant until the next rate case.

4. Cost trackers and rate riders may be applied to some costs that are partly or wholly beyond a utility's control.

5. A utility's allowed return on equity is set by the commission in a rate case, and this return is earned on all investments that are placed into the utility's rate base. Actual profits may deviate from the allowed return on equity, depending upon many factors both within and outside a utility's control.

6. Prudency reviews are used retrospectively (after the investment has occurred) to ensure costs are reasonable. Cost disallowances as a result of prudency reviews are rarely applied, and then only in cases of egregious mismanagement or cost overruns.

There are several significant, widely-recognized financial incentives underlying traditional cost-of-service regulation. The most significant incentives include the following:

Capital expenditures. When a utility's rate of return is greater than the cost of borrowing, utilities have a financial incentive to maximize their capital expenditures in order to increase rate base and thereby increase profits. This is often referred to as the Averch-Johnson effect. In theory, prudency reviews can mitigate some of the incentive to maximize capital expenditures. However, in practice prudency reviews and disallowances are rare, burdensome, and are mostly applied to large capital expenditures.

Sales. Traditional cost-of-service regulation creates an incentive for a utility to maximize sales in order to increase profits. Whenever a utility's short-term marginal costs are lower than its average costs (i.e., the costs embedded in rates), then it can increase profits by increasing sales. This "throughput incentive" poses a significant financial disincentive to utilities with regard to energy efficiency and distributed generation. This incentive to increase sales, combined with the utility focus on capital expenditures, significantly undermines utility motivation to apply least-cost planning principles and to develop the most cost-effective balance of supply-side and demand-side resources. As a consequence, customers must cover significantly higher energy costs than necessary.

Regulatory lag. Regulatory lag refers to the period between rate cases when the utility is incurring costs, but rates have not yet been adjusted to recover these outlays. Some industry observers claim that regulatory lag provides utilities with incentives for efficient management and cost control, because utilities are able to benefit from any cost savings that they create between rate cases. On the other hand, regulatory lag can pose financial challenges for a utility, causing it to apply for rate cases more frequently. In general, the incentive created by regulatory lag depends upon whether the utility's average costs are decreasing or increasing relative to revenues (Costello 2014).

Risk. Under traditional cost-of-service regulation, utilities are generally permitted to recover all capital costs, with a profit. This certainty of cost recovery provides little incentive to reduce risks associated with major capital expenditures—expenditures that can involve considerable uncertainty and risk (Binz et al. 2012). Cost trackers and rate riders further eliminate risks to the utilities by shifting all of the risks associated with such costs to customers. For example, fuel adjustment charges can reduce incentives for the utility to optimize its generation portfolio to account for the risk of fuel cost increases.

Innovation. There is little incentive for utilities to adopt innovative practices, technologies, or resources under traditional cost-of-service regulation. Utilities have considerable certainty that regulators will allow them to recover costs of prudently incurred investments in conventional projects, but much less certainty about being allowed to recover costs associated with innovative practices and technologies with uncertain results.

Many states continue to rely upon some form of cost-of-service regulation, even in states that have restructured their electricity markets. Regulators in these states frequently employ a variety of tools to improve the alignment of regulatory incentives with the public interest, such as revenue decoupling, forward-looking costs on some items, and performance incentive mechanisms.

Performance incentive mechanisms under traditional cost-of-service regulation typically have been developed to improve service or reduce costs, for example, reliability, power plant performance, cost of renewable generation, or O&M costs. Some states have developed performance incentive mechanisms to support specific resource goals, such as increasing renewable energy generation, energy efficiency savings, and resource diversity.

Performance-Based Regulation

Performance-based regulation (PBR) was introduced in the US electric sector in the 1980s and became popular in the 1990s as an alternative to cost-of-service regulation, particularly in states that introduced retail competition (Sappington et al. 2001). One of the goals of PBR was to improve upon the financial incentives provided under traditional cost-of-service regulation, and to provide incentives more focused on operational efficiency and cost reduction.

Performance-based regulation is characterized by the following elements:

1. The time period between rate cases is fixed at the outset of each period, and is designed to be long enough to provide the utility with incentives to reduce operating costs and keep the operational savings between rate cases.

2. A price cap (or a revenue cap) is used to set prices for a fixed period of time.

3. Automatic adjustments to the price (or revenue) cap may be established to account for expected cost changes between rate cases. These frequently include automatic increases to account for inflation, coupled with automatic reductions to encourage productivity improvements. Many states adopted the "RPI – X" formula, where RPI is the retail price index and "X" is a productivity factor.

4. Trackers may be established to allow the utility to recover certain types of costs outside of the price (or revenue) cap, typically costs that are volatile and beyond a utility's control. Some states also allow trackers for major capital expenditures, because these costs are large and lumpy, and may therefore be difficult to accommodate in a fixed price (or revenue) cap.

5. Performance incentives are applied for key aspects of customer service, in order to ensure that utilities do not allow service to degrade in their pursuit of reduced costs and greater efficiencies.

6. Earnings sharing mechanisms are established to ensure that the utility's earned profits are neither excessive nor insufficient.

There are many different variations of PBR used in the United States today, incorporating different forms of the elements listed above.[3] The WIEB report *New Regulatory Models* referenced above provides several examples (Aggarwal and Burgess 2014). Also, there are many terms used to describe different combinations of these elements. The term "alternative ratemaking" is sometimes used synonymously with PBR. Some states use the term "multi-year rate plan" to refer to rates that are set for a fixed period of time, with automatic adjustments and cost trackers between rate cases. Such multi-year rate plans may or may not include performance incentives.

In theory, PBR is intended to provide more direct financial incentives for utilities to reduce costs, without heavy-handed, ongoing oversight from regulators. The key to this incentive is the fixed period between rate cases. If the utility succeeds in keeping its costs below its allowed revenues, it can keep the excess revenues. Capital investments made during the period should lead to reduced operations and maintenance costs, which would accrue to the utility until the next rate case.

In practice, there are many incentives embedded in PBR mechanisms, with various implications:

- The fixed period between rate cases should provide utilities with an incentive to reduce operating costs. However, the impact of this incentive depends upon the length of time between rate cases, where relatively shorter periods will result in more muted incentives.

- The productivity factor should provide an incentive to increase productivity. However, establishing the right productivity factor can be difficult, particularly when (a) there are few comparable peer utilities for comparison purposes; (b) utilities need to replace aging infrastructure; (c) utilities (or the industry) are in a period of rapid transition, in terms of markets, technologies, or operations; and (d) historical costs and practices are not a good indication of what future costs and practices will be.

- Placing certain types of costs into trackers eliminates the utility's incentive to optimize those costs and transfers the risks associated with those costs to ratepayers.

- If major capital expenditures are recovered through a fully reconciling cost tracker, utilities have little incentive to ensure that those costs are planned and managed as efficiently as possible. In such a case, it may be important to design a major capital cost tracker so as to provide such

[3] For a relatively recent survey, see Lowry, Makos, and Waschbusch 2013.

incentives, for example by establishing a mechanism that requires the utility to absorb a significant portion of any cost overruns.

- If major capital expenditures are not recovered through a cost tracker, it can become much more challenging to establish a price (or revenue) cap and a productivity index that provides cost control incentives while allowing the utility to adequately recover capital costs and protect consumers.[4]
- Performance incentives can be useful to prevent service degradation in light of pressures to reduce costs, or to improve performance in some areas. However, performance incentives must be designed carefully to achieve the desired results. The effective design of performance incentives is discussed throughout later chapters of this report.

In recent years, several PBR investigations have attempted to address some of the challenges associated with the incentives and implications listed above.[5] In addition, many of these issues have been investigated and addressed by Ofgem, the electricity and gas regulator in the United Kingdom, the first regulator to apply PBR to electricity utilities, and the creator of the model upon which many US PBR designs were based. After several decades of experience with PBR, Ofgem has significantly modified its PBR mechanism. The new mechanism being developed in the UK is referred to as RIIO (Revenues = Inputs + Incentives + Outcomes), and is discussed in some detail in Appendix A.

New Regulatory Models

In many states, electricity load growth has slowed significantly due to many factors, including increased use of distributed energy resources (DER) such as energy efficiency and distributed generation. At the same time, the electric industry is experiencing many forces that frequently increase costs, including: the need to replace aging infrastructure, increased transmission needs, requirements to reduce environmental impacts, and pressure to modernize the electric grid. Combined, these factors are simultaneously increasing the need for utility capital expenditures while reducing the revenue from sales growth they have historically relied upon. Traditional cost-of-service regulation and traditional PBR mechanisms may be ill-equipped to handle these challenges, and may not provide utilities with the incentives or the regulatory guidance needed to address them.

Some jurisdictions and stakeholders have begun to investigate new regulatory and utility business models to address the limitations of the current systems.[6] Several proposals in these contexts focus on

[4] See, for example, Direct Testimony of Tim Woolf before the Maine Public Utilities Commission in Docket No. 2013-168, *Central Maine Power Request for Approval of an Alternative Rate Plan (ARP 2014)*, December 12, 2013.

[5] See, for example, Maine Public Utilities Commission Docket No. 2013-168 and Hawaii Public Utilities Commission Docket No. 2013-0141.

[6] See, for example, the New York Public Service Commission Case Number 14-M-0101, *Reforming the Energy Vision*; Hawaii Public Utilities Commission, Decision and Order No. 32052, Exhibit A: *Commission's Inclinations on the Future of Hawaii's Electric Utilities,* and Hawaii Public Utilities Commission Docket 2013-0141; e21 Initiative 2014; GTM Research 2015; and Lehr 2013.

PBR mechanisms, with the overall goal of creating financial incentives that are based more on performance and less on recovery of costs.[7]

These proposals include several modifications to the way that PBR is currently applied in the United States. For example:

1. Expand the types of performance metrics applied to utilities to include emerging performance areas such as system efficiency, customer engagement, network support services, or environmental goals (see Section 3.2). This is intended to provide regulatory guidance and financial incentives regarding the variety of outcomes that are important for delivering quality service and meeting state energy policy goals.

2. Shift the financial incentive away from investments in rate base and towards achieving performance goals. This can be accomplished by reducing the portion of revenue requirements that a utility recovers from rate base, and comparably increasing the portion of revenue requirements that can be recovered from performance metrics.[8]

3. Establish longer periods between rate cases. This is intended to increase the magnitude of the financial incentive to increase productivity and reduce costs between rate cases.

4. Provide more up-front guidance from regulators and stakeholders with regard to future major capital expenditures. This is intended to provide utilities with greater flexibility and incentive to adopt innovative and emerging technologies and practices.

Many of these modifications are consistent with those that have been adopted recently in the UK RIIO model, suggesting that the lessons learned from the UK PBR experience may be relevant to the new regulatory and utility business models being considered in the United States. This is discussed in more detail in Appendix A.

Some states have already established performance metrics or incentive mechanisms to address emerging performance areas, such as customer retail choice, grid modernization, and distributed generation interconnections. Examples and further discussion of metrics and incentives to address these emerging areas are provided in Chapter 3.

Performance Metrics and Incentives Can Be Applied in Any Regulatory Context

One of the advantages of performance metrics and incentives is that they can be used in any regulatory context. However, it is critical that performance metrics and incentives be specifically tailored to the

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[7] See, for example, Energy Industry Working Group 2014; Malkin and Centolella 2014; Blue Planet Foundation 2014; e21 Initiative 2014; Massachusetts Grid Modernization Steering Committee 2013.

[8] For example, under RIIO, the British distribution utilities face rewards and penalties of approximately five percent of their base distribution revenues (CEPA LLP 2013).

existing (or anticipated) regulatory context in each state, to ensure that they adequately complement and balance the financial incentives provided by that regulatory context.

> In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance, or areas where regulators see opportunities for greater efficiencies or reduced costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.

> In a state with performance-based regulation, performance metrics and incentives might be especially important to prevent the degradation of service as a result pressures to reduce costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as those provided by price (or revenue) caps, fixed periods between rate cases and cost trackers.

> In a state developing new regulatory and utility models, performance metrics and incentives might be especially important to re-direct utility management priorities toward desired performance outcomes, and shift the source of utility revenues away from capital investments and toward those desired outcomes. Performance metrics should be applied to the priority performance areas, and performance incentives should be designed to complement, offset, or mitigate existing financial incentives.

> In any state, performance metrics and incentives can be used to promote resources that are not supported or encouraged by the existing regulatory system, such as energy efficiency and renewable resources.

> In any state, performance metrics and incentives can be used to provide guidance on how utilities can meet state regulatory policy goals, such as improving reliability and resiliency, empowering customers to reduce bills, or minimizing the cost of complying with the EPA Clean Power Plan.

> In any state, performance metrics and incentives can be used to encourage utilities to investigate and adopt innovative technologies that are not otherwise supported by the existing regulatory system, such as distributed generation, grid modernization, storage technologies, or practices to support electric vehicles.

3. PERFORMANCE METRICS

3.1. Introduction

There are significant advantages of establishing performance metrics—even without administering financial incentives. Reporting utility performance facilitates regulatory oversight and encourages utilities to strive for better performance, as subpar performance is likely to result in negative public response and greater regulatory scrutiny. Implementing tracking and reporting metrics is straight-forward and low risk. It can be designed to present little administrative burden on either regulators or utilities, while providing valuable information.

3.2. Performance Dimensions That May Warrant Metrics

Performance incentive mechanisms have historically been used to help achieve traditional goals of reliable, safe, and low-cost utility service. Today, new incentives are being proposed to attain a whole new set of energy policy objectives, such as environmental quality, fuel diversity, fast-responding resources, and customer empowerment, to name a few.

For example, states throughout the West are facing stricter environmental standards for criteria air pollutants, water use, and carbon emissions, and many states are experiencing rapid growth in rooftop solar PV.[9] In response to these new regulations and the growth of distributed generation, utilities are investing billions of dollars in new renewable energy capacity[10] and transmission and distribution infrastructure (including smart grid technologies), and will need to procure significant amounts of resources to accommodate variations in net load (including demand response, advanced wind and solar control technologies, and storage).[11]

To ensure that utilities are operating efficiently and meeting energy policy goals, regulators may wish to track a variety of dimensions of utility performance, and possibly also implement financial rewards or penalties in areas where additional incentive is needed. The figure below highlights a variety of dimensions of utility performance that may warrant tracking and reporting or incentives. Performance dimensions generally fall into three categories: traditional goals, new business models, and environmental goals. Some aspects of utility performance have been important in more than one area;

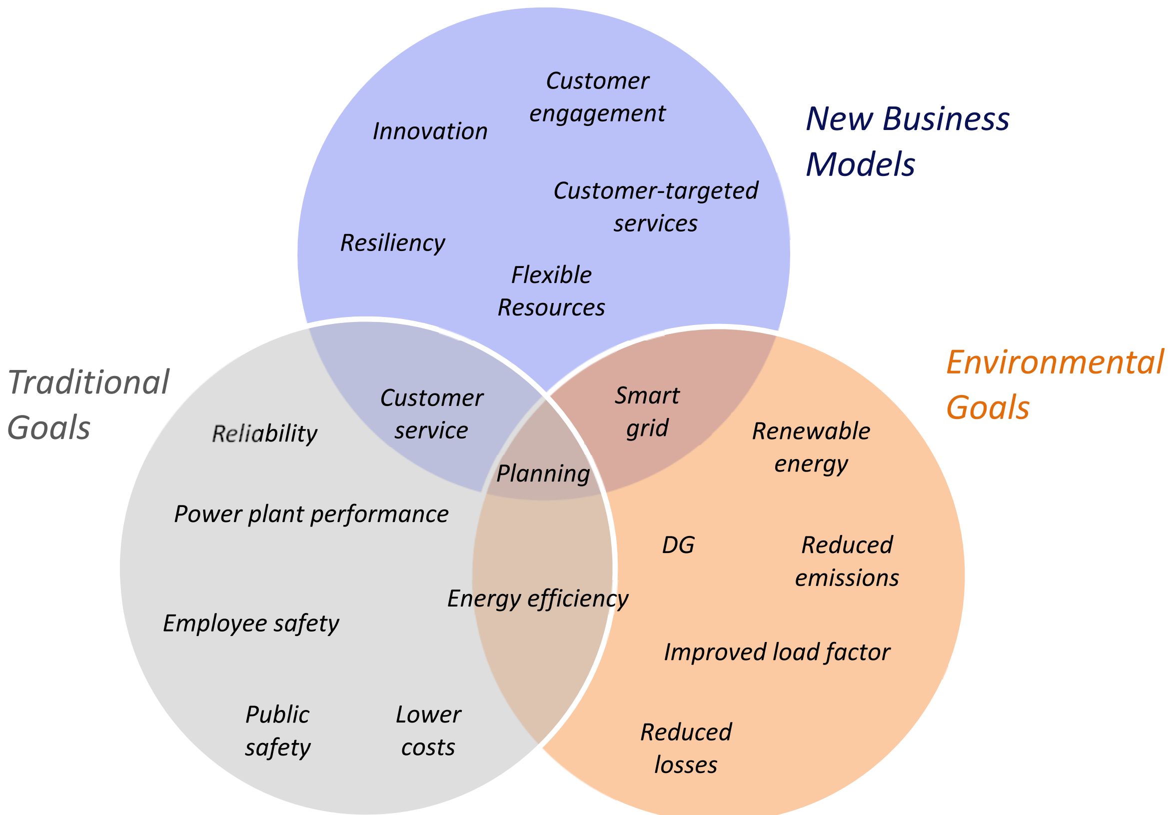
[9] Residential installations of PV are expanding at a rate of more than 50 percent year-over-year, with California, Arizona, and Colorado among the top states (SEIA/GTM Research 2013).

[10] The Western Electricity Coordinating Council (WECC) predicts that renewable resources in the West (excluding conventional hydro) will produce nearly 17 percent of the region's energy by 2022 (WECC Staff 2013).

[11] During certain times of the year, total system load net of solar and wind changes rapidly producing an effect known as the "duck curve." These very fast changes to net load (total load minus the output of variable resources) require fast-ramping resources to mitigate reliability impacts caused by the sudden appearance or departure of variable energy resources (Lazar 2014).

for example, successful implementation of cost-effective energy efficiency can reduce emissions associated with fossil generation (an environmental benefit) and defer or avoid new generation, capacity, transmission, and distribution resources, resulting in cost savings (a traditional focus of utility performance regulation). Planning has a critical role in informing regulatory outcomes across all three areas, and thus it takes a central location in the Venn diagram below.

Figure 2. Dimensions of Utility Performance That May Warrant Tracking or Incentives



Traditional Performance Areas

Several aspects of utility performance have a long history of being tracked and reported to state utility commissions, federal regulatory agencies, or otherwise made publicly available. These traditional performance areas are reliability, safety, customer satisfaction, power plant performance, and costs; as indicated in Table 3.

Metrics for monitoring these traditional performance areas are generally well developed, and the data readily available. Where standard metric definitions exist and have been adopted by utilities, regulators may wish to track and compare performance across utilities within a state or across the region. (However, peer group comparisons may not be appropriate for the determination of rewards and penalties without controlling for differences among utilities. This is discussed in greater detail in later sections.)

Table 3. Traditional Performance Areas

Performance Dimension	Purpose
Reliability	To indicate the extent to which service is reliable and interruptions are remedied quickly
Employee Safety	To ensure that employees are not subjected to excessive risks
Public Safety	To ensure that the public is not subjected to excessive risks
Customer Satisfaction	To ensure that the utility is providing adequate levels of customer service
Plant Performance	To indicate the performance of specific generation resources
Costs	To indicate the cost of supply side resources

Innovative and Emerging Performance Areas

In order to address evolving industry challenges, regulators are beginning to focus attention on new aspects of utility performance, including overall system efficiency such as system load factor, use per customer, etc.; customer engagement (including tools to empower customers to better manage their bills); network support services; environmental impacts; and clean energy goals. Examples of these emerging performance areas and metrics for tracking them are provided in Table 4.

Table 4. Emerging Performance Areas

Performance Dimension	Purpose
System Efficiency	To indicate the extent to which the utility system as a whole is being operated more efficiently
Customer Empowerment	To indicate the extent to which customers are participating in demand-side programs or installing demand-side resources
Network Support Services	To indicate the extent to which customers and third-party service providers have access to networks
Environmental Goals	To indicate the extent to which the utility and its customers are reducing environmental impacts, particularly related to climate change

3.3. Defining Metrics

Simply defined, a metric is a standard of measurement. In assessing utility performance, metrics play a central role in enabling regulators to determine how well a utility is performing in the areas of interest. Defining a metric typically involves the following:

- Specific data definitions
- A precise formula used to quantify each metric

- Data collection and analysis practices and techniques, including identification of the entity responsible for collecting and reporting the data
- Requirements for measurement and reporting
- Verification techniques and entity responsible for verifying data

For example, a common metric for measuring reliability is the sustained average interruption duration index, SAIDI. The data include the average number of utility customers and the number of sustained outages, and may or may not exclude outages from major storms. However, to employ this metric, the definition of both a "sustained outage" and "major storm" needs to be clarified, the frequency of measurement (e.g., annual or quarterly) defined, and a verification process established.

Table 5 through Table 10 contain metrics for traditional performance areas that regulators may find useful for measuring utility performance, including metrics for reliability, employee safety, public safety, customer satisfaction, plant performance, and costs. Table 11 through Table 14 contain metrics for emerging performance areas, including system efficiency, customer engagement, network support services, and environmental goals.

These tables are intended to cover a wide range of issues of importance to regulators, but do not exhaust the universe of metrics that regulators may wish to consider. Nor are these metrics necessarily the "best" means of measuring performance in a certain area. The first step in determining which metrics will best serve the needs of a particular state is to articulate the policy goals that the state wishes to achieve. Regulators should then design metrics that are capable of accurately and reliably measuring progress toward these goals. The metrics includes in the tables below (and their formulas) provide examples of existing or potential metrics that could be implemented, but may not necessarily suit a particular jurisdiction's needs.

Examples of Innovative Performance Metrics

As the electric industry transforms, new metrics are being proposed to measure how well utilities meet evolving customer needs. Many of these existing or proposed performance metrics are described in more detail in the appendix, including:

- *Peak load reductions (Illinois)*
- *Stakeholder engagement (Illinois, Hawaii)*
- *Customers accessing energy usage portals (Illinois)*
- *Effective resource planning (Hawaii)*
- *System load factor (Illinois)*
- *Line loss reductions (UK, Illinois)*
- *Distributed generation interconnections (UK, Illinois, Hawaii)*
- *Cost of renewable energy (California)*
- *Carbon intensity (Hawaii)*
- *Renewable energy curtailments (Hawaii)*

See Appendix A for detailed case studies describing some of these metrics and performance incentive mechanisms.

Table 5. Reliability Performance Metrics

Metric	Purpose	Metric Formula
System Average Interruption Duration Index (SAIDI)	Indicator of sustained interruptions experienced by customers	Total customer minutes of sustained interruptions / total number of customers
System Average Interruption Frequency Index (SAIFI)	Indication of how many interruptions are experienced by customers	Total number of customer interruptions / total number of customers
Customer Average Interruption Duration Index (CAIDI)	Indicator of the length of interruptions experienced by customers	Total minutes of sustained customer interruptions / total number of interruptions
Momentary Average Interruption Frequency Index (MAIFI)	Indicator of momentary interruptions experienced by customers	Total number of momentary customer interruptions per year / total number of customers
Power quality	Indicator of voltage changes, which can cause damage to end use equipment and frequency deviations	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker; CPS 1 and 2 that measure frequency excursions

Table 6. Employee Safety Performance Metrics

Metric	Purpose	Metric Formula
Total Case Rate (TCR)	Indicator of employee injuries, fatalities, and productivity losses due to work-related incidents	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000) / Employee hours worked[12]
Days Away, Restricted, and Transfer (DART) case rate	Indicator of employee injuries, restrictions, and productivity losses due to work-related incidents	(Number of work-related days away from work and job transfers or restrictions due to work accidents times 200,000) / Employee hours worked
Days Away From Work (DAFWII) case rate	Indicator of employee injuries and productivity losses due to work-related incidents	(Number of work-related days away from work due to work accidents times 200,000) / Employee hours worked

Table 7. Public Safety Performance Metrics

Metric	Purpose	Metric Formula
Incidents, injuries, and fatalities (electric)	Indicator of incidents, injuries, and fatalities associated contact with the electric system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity
Emergency response time (electric)	Indicator of speed of response to emergency situations involving the electric system	Percent of electric emergency responses within 60 minutes each year
Incidents, injuries, and fatalities (gas)	Indicator of incidents, injuries, and fatalities associated with the gas system by members of the public	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause
Emergency response time (gas)	Indicator of speed of response to emergency situations involving the gas system	Average minutes for gas emergency response
Leak repair performance (gas)	Indicator of speed of response to non-emergency situations involving the gas system	Average days for repair of minor and non-hazardous leaks

12 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). (U.S. BLS 2013)

Table 8. Customer Satisfaction Performance Metrics

Metric	Purpose	Metric Formula
Call center answer speed	Indicator of customer ease of contacting utility	Percentage of calls answered within 30 seconds
Transaction surveys	Indicator of how well the utility is meeting customer needs based on recent contact with utility	Percentage of customers satisfied with their recent transaction with the utility
Customer complaints	Indicator of how well the utility is meeting customer needs	Formal complaints to commission (per 1,000 customers) over a set period. May also track complaints resolved.
Order fulfillment	Indicator of response time to service requests and outages	Speed with which orders for service installation and termination, outage responses, and meter re-reading are fulfilled
Missed appointments	Indicator of how well the utility is meeting customer needs	Percentage of appointments not met for meter replacements, inspections, or any other appointments in which the customer is required to be on the premises
Avoided shutoffs and reconnections	Indicator of efficient provision of services to low income customers	Disconnects and reconnections avoided by customer percentage of income payment plans or other means
Residential customer satisfaction	Indicator of how well the utility is meeting the needs of residential customers	Electric Utility Residential Customer Satisfaction index, Gas Utility Residential Customer Satisfaction index
Business customer satisfaction	Indicator of how well the utility is meeting the needs of business customers	Electric Utility Business Customer Satisfaction index, Gas Utility Business Customer Satisfaction index

Table 9. Plant Performance Metrics

Metric	Purpose	Metric Formula
Fuel usage	Indication of the fuel consumption by specific generation resources	Quantity of fuel burned
Heat rate	Indication of the efficiency of specific generation resources	Average BTU per kWh net generation
Capacity factor	Indication of actual generation by a specific resource	Average energy generated for a period / energy that could be generated at full nameplate capacity

Table 10. Cost Performance Metrics

Metric	Purpose	Metric Formula
Capacity costs	Indicator of costs of peak consumption	Cost per kW of installed capacity
Total energy costs	Indicator of costs of all hours consumption	Expenses per net kWh
Fuel cost	Indicator of costs of fuel input	Average cost of fuel per kWh net gen and per Million BTU; total fuel costs
Effective resource planning*	Indicator of efficacy, breadth, and reasonableness of resource planning process	Numerous metrics regarding incorporation of stakeholder input, consideration of all relevant resources, use of appropriate assumptions and modeling tools, etc.
Cost-Effective Alternative Resources*	Indicator of system savings through use of cost-effective alternatives to traditional infrastructure	$/MW cost of alternative portfolio relative to the $/MW cost of traditional investment

**See Appendix A, New York and Hawaii case studies, for more information on these metrics.*

Table 11. System Efficiency Performance Metrics

Metric	Purpose	Metric Formula
Load factor	Indication of improvement in system and customer load factors over time	Sector average load / sector peak load
		Monthly system average load / monthly system peak load
Usage per customer	Indication of customers' energy consumption changes over time	Sector sales / sector number of customers
Aggregate Power Plant Efficiency	Indication of the efficiency and availability of supply-side generation resources in total	System average BTU per kWh net generation (heat rate)
		Equivalent Forced Outage Rate (EFOR) = Equivalent Forced Outage Hours / (Period Hours – Equivalent Scheduled Outage Hours)
		EFORd: variant of EFOR, measuring the probability that units will not meet generating requirements demand periods because of forced outages or derates
		Weighted equivalent availability factor: over a given operating period, the capacity-weighted average fraction of time in which a fleet of generating units is available without any outages and equipment or seasonal deratings
Flexible Resources	Indication of the capacity of supply side resources to quickly respond to changes in net load	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)
System losses (electric)	Indication of reductions in losses over time	Total electricity losses / MWh generation, excluding station use
System losses (gas)	Indication of reductions in gas losses over time	Total gas losses / total sales

Table 12. Customer Engagement Performance Metrics

Metric	Purpose	Metric Formula
Energy efficiency (EE)	Indication of participation, energy and demand savings, and cost effectiveness of EE programs	Percent of customers per year
		Annual and lifecycle energy savings
		Annual and lifecycle peak demand savings (MW)
		Program costs per MWh energy saved
Demand response (DR)	Indication of participation and actual deployment of DR resources	Percent of customers per year
		Number of customers enrolled
		MWh of DR provided over past year
		Potential and actual peak demand savings (MW)
Distributed generation (DG)	Indication of the technologies, capacity, and rate of DG installations, and whether net metering policies are supporting DG growth	Number of installations per year
		Net metering installed capacity (MW)
		Net metering MWh sold back to utility
		Net metering number of customers
		MW installed by type (PV, CHP, small wind, etc.)
Energy storage	Indication of the technologies, capacity, and rate of customer-sited storage installations and their availability to support the grid	Number of installations per year
		MW installed by type (thermal, chemical, etc.)
		Percent of customers with storage technologies enrolled in demand response programs
Electric vehicles (EVs)	Indication of customer adoption of EVs and their availability to support the grid	Number of additions per year
		Percent customers with EVs enrolled in DR programs
Information availability	Indicator of customers' ability to access their usage information	Number of customers able to access daily usage data via a web portal
		Percent of customers with access to hourly or sub-hourly usage data via web
Time-varying rates	Indication of saturation of time-varying rates	Number of customers on time-varying rates

Table 13. Network Support Services Metrics

Metric	Purpose	Metric Formula
Advanced metering capabilities	Indication of metering functionality	Number of customers with AMI and AMR
		Energy served through AMI
Interconnect-ion support	Indication of DG installation support	Average days for customer interconnection
		Customer satisfaction with interconnect process
Third-party access	Indication of network access by third-party vendors	Open and interoperable smart grid infrastructure that facilitates third-party devices
		Third-party vendor satisfaction with utility interaction
Provision of customer data	Indication of customer access to relevant data	Customers able to authorize third-party access electronically
		Percent of customers who have authorized third-party access
		Third-party data access at same granularity and speed as customers

Table 14. Environmental Goals Performance Metrics

Metric	Purpose	Metric Formula
SO_2 Emissions	High-level indicator of emissions	Tons
Average NOx Rate	High-level indicator of emissions	lbs/MMBtu
CO_2 emissions	High-level indicator of emissions	Tons CO_2
Carbon intensity	Indicator of carbon emissions that accounts for changes in customers	Tons CO_2 / customer
System carbon emission rate	Indicator of carbon emissions that accounts for volume of generation	Tons CO_2 / MWh sold
Clean Power Plan (CPP) emission rate	Indicator of compliance with EPA's CPP	lbs CO_2 from fossil generators / (Fossil Fuel Generation (MWh) + 5.8% Nuclear Generation (MWh) + Renewable Generation (MWh) + Cumulative Energy Efficiency (MWh))
Fossil carbon emission rate	Indicator of carbon emissions accounting for improved efficiency and dispatch of fossil resources	Tons CO_2 / MWh fossil generation
Fossil generation	Indication of reduction in fossil fuel use	Fossil MWh percent of total generation
Renewable generation	Indicator of development of renewable power	Renewable percent of total generation

3.4. Design Principles

The following design principles should be considered when establishing performance metrics. Metrics should be:

1. Tied to the policy goal
2. Clearly defined
3. Able to be quantified using reasonably available data
4. Sufficiently objective and free from external influences
5. Easily interpreted
6. Easily verified

These principles are discussed in more detail below.

Metrics Should be Tied to Policy Goals

To be useful, metrics should help stakeholders understand the degree to which policy goals are being achieved. Too often, metrics report data without conferring useful information. For example, if a policy goal is to improve the system load factor by reducing peak demand, it is not meaningful to simply report the number of customers enrolled in a demand response program, as this provides no information regarding whether these customers actually reduced demand, and by how much, during peak periods. To be useful, a metric should reflect whether or not the underlying policy goal is being met; e.g., whether peak demand has decreased over the prior year.

Metric Definitions Should be Unambiguous

How a metric is calculated should be defined in a way that leaves little ambiguity regarding precisely what data are included and excluded, the units of measurement, the frequency of measurement, and the methods used to analyze and report it. Failure to do so may impair meaningful comparisons of performance across years or utilities, while potentially increasing contention during proceedings (see Nevada case study in sidebar).

Where possible, metrics should be defined in a manner consistent with national or regional standards and definitions in order to facilitate comparisons across utilities. However, regulators should not be constrained by these definitions; similar metrics that report slightly different data may be more useful for determining whether utilities are achieving a policy goal. In such cases, data under both the standard definition and the jurisdiction-specific definition could be reported.

Careful attention to metric definitions is necessary to simplify data review, ensure that metrics will be reported consistently over time, and enable meaningful comparisons. The specificity required for data definitions should not be underestimated. For example, although there exists a common industry standard for measuring and reporting reliability performance, few utilities adhere to this standard.[13] Thus standard metrics such as System Average Interruption Duration Index (SAIDI) are actually often reported in different ways, with definitions of "major events" or the length of a "sustained interruption" varying across utilities and jurisdictions. In fact, sometimes these metrics are reported inconsistently even within a jurisdiction.[14]

Metrics Should be Able to be Quantified Using Reasonably Available Data

Data that are not readily available may be costly to collect. Making use of existing industry standards and generally available data can ease administrative burdens to regulators and utilities alike, and, where appropriate, can facilitate benchmarking utility performance against others. Fortunately, a large amount of data is already reported by utilities to the Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), the Environmental Protection Agency (EPA), the North American Electric Reliability Corporation (NERC), and other entities. Specific data sources for many of the metrics presented in Tables 4 and 5 are provided in Appendix B.

Fuel Diversity in Nevada

Per Nevada administrative code NAC 704.9484, the Public Utilities Commission can grant critical facility (CF) status for the purpose of protecting reliability; promoting resource diversity; developing renewable energy resources; fulfilling specific statutory mandates; or promoting retail price stability. Owners of CFs may be granted special ratemaking treatment (e.g., deferral of incremental O&M costs) or other incentives (return on equity adder for the facility, or including construction work in progress in rates).

The criteria used to evaluate whether a facility meets the criteria for CF status have not been explicitly defined, however. This has resulted in ambiguity for resource developers, contentious proceedings, and uncertainty regarding whether policy goals are being achieved.

By 2010, all approved requests for CF status involved construction of gas-fired generation resources, leading to concerns about over-reliance on gas. Clearly articulated goals, metrics, and targets could have helped to avoid this over-investment in a single resource and reduced the litigation associated with related proceedings.

For more information, see PUC order dated July 28, 2010 in Docket Nos. 10-02009. 10-03022. and 10-03023.

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[13] The Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-2003 is intended to increase consistency among utility reliability reporting practices, but adoption of the standard is voluntary. Many utilities report reliability metrics (such as SAIDI and SAIFI) using somewhat different data definitions (Eto and LaCommare 2009).

[14] For example, the Maryland PSC staff noted that "the Maryland utilities have not been consistent with their treatment of planned outages when reporting reliability metrics to the Commission. The investor-owned utilities report reliability metrics excluding planned outages and the cooperatives report reliability metrics including planned outages" (MD PSC Staff 2011, 6).

Metrics Should Be Sufficiently Objective and Largely Free from Exogenous Influences

Regulators may wish to track many metrics in order to better understand what is happening in their state's electric system. However, not all of these metrics are good indicators of utility performance. To evaluate how utilities themselves are performing, and particularly to administer penalties or rewards, the metrics chosen should be sufficiently objective and free from exogenous influences. Otherwise, factors that the utility has no control over can influence the results, obscuring the role that utility management played in the outcome.

For example, average customer bills can be a tempting metric to use to evaluate utility efficiency. However, average bills are impacted by numerous factors, ranging from fossil fuel prices, costs of steel and other commodities, weather, and the economy. These exogenous factors prevent average bills from serving as a sufficiently objective metric.

Objectivity does not necessarily mean that all data must be purely quantitative or measured using physical units. For example, customer satisfaction surveys can be designed to be sufficiently objective through the use of specific, targeted survey questions (see sidebar). Surveys can be conducted in phases over time so that no single event (e.g., a storm related outage) has too strong of an influence on the results.

Customer Survey Results as an Objective Metric

A number of states require utilities to report customer satisfaction survey results. In Massachusetts, poor customer satisfaction survey scores may lead to substantial financial penalties. The application of penalties to survey results was recently opposed by many Massachusetts utilities, who argued that surveys are too subjective. However, the Massachusetts Department of Public Utilities reaffirmed that surveys can provide sufficiently objective information, if designed and administered well.

To enhance the quality of information collected in the surveys, the Massachusetts survey was modified from a more general question regarding customer satisfaction to very specific questions about whether customers' issues were resolved after the first contact with the utility, and how easy it was to conduct business with the utility. The specificity of these questions helps to control for the influence of other factors (such as electricity rates or media coverage) on customers' responses.

See DPU Order dated July 11, 2014, Investigation by the DPU on Its Own Motion Regarding the Department's Service Quality Guidelines, D.P.U. 12-120-B

Metrics Should Be Easily Interpreted

Metrics that are readily interpreted generally provide stakeholders with a better understanding of utility performance. To improve interpretability, metrics should exclude the effects of factors outside of the utility's control to the extent possible. For example, a metric that measures the time required to interconnect distributed generation could be limited to include only the time from when the application is deemed complete to the time when the application is approved. This definition would thereby exclude any delays due to customer inaction.

Another means of improving interpretability is to use per-unit metrics to facilitate comparison across time and across utilities. Examples include percentages (e.g., percentage line losses), per-kWh (e.g., average emissions per kWh of generation), and per-customer (e.g., O&M costs per customer). For example, if the objective is to increase utility efficiency by reducing costs, a metric based on O&M costs per customer may be more informative than total O&M costs, as the number of customers may change over time.

Metrics Should be Verifiable

Data validity and reliability is essential for ensuring that utility performance is being accurately measured. For this reason, external verification of performance data is often relied upon, and the metrics chosen should lend themselves to such verification.

Where commissions have implemented performance tracking and reporting, commission staff frequently review and verify data, but independent third-party evaluators are also used, particularly when financial rewards or penalties are at stake. Greater use of third-party evaluators may help to prevent performance incentive gaming, such as that which occurred in California in the 1990s-2000s (see sidebar).

The use of straight-forward data collection and analysis techniques should be used where possible, as it improves transparency, enabling regulators and other stakeholders to more easily determine the data's accuracy. This makes manipulation of data more difficult and reduces the costs of oversight, as there is less need to hire specialized consultants (Costello 2010). In contrast, metrics that require complex data collection or analysis techniques make review and interpretation more difficult while increasing costs.

Gaming of Performance Incentive Mechanisms in California

In the late 1990s and early 2000s, Southern California Edison operated under a PBR plan with performance incentive mechanisms for customer satisfaction (as measured through surveys) and employee health and safety. The problems with the customer survey were many, but the most serious instances arose when utility employees sometimes falsified customer contact information to screen out customer interactions that might result in negative customer satisfaction surveys.

The employee health and safety performance mechanism was similarly problematic. Not only did the incentive mechanism actually discourage workers from reporting injuries in order to avoid jeopardizing safety incentive compensation for their group, but some supervisors participated in or encouraged under-reporting of data. Methods used to disguise injuries and avoid internal reporting included: employee self-treatment; treatment by personal physicians rather than the company doctor; and timecard coding of lost time as sick days or vacation. See Appendix A for further details.

3.5. Dashboards for Data Reporting

To be useful, performance metric data must be presented in an easily accessible, up to date, and properly contextualized manner. Without context, such as comparison of current performance to historical trends or benchmarks, utility performance data convey little meaningful information to regulators and stakeholders. Similarly, when performance statistics are not aggregated in a central location, but are provided only in filings made in various dockets on different reporting cycles, it becomes difficult and time-consuming to develop a holistic view of utility performance across multiple dimensions.

Data dashboards provide a means of collecting utility performance information in a central location and presenting the data in a transparent and meaningful way. A designated website—hosted either by the utility or the commission—provides a useful forum for displaying performance information, ideally through both interactive graphs and downloadable data. Dashboards allow data to be compared across years and between utilities. If a performance target is set, the dashboards enable all users to quickly determine whether the utility is meeting or failing to achieve the targets. Data dashboards should complement, rather than be a substitute for, prudency reviews.

Dashboards should be:

- **Accessible:** Performance data should be presented in a publicly-accessible manner, such as on a designated website, and should include a means for downloading the underlying data.

- **Contextualized:** Performance targets, historical performance data, peer performance, and explanations of any major events that impacted performance should be included in the data presentation.

- **Clear and concise:** Performance should be presented in graphs that are clear and easily interpreted. An explanation of how the metric is calculated should also be included. Highly technical terms should be adequately defined or avoided.

- **Comprehensive:** The dashboard website should provide data and graphs for all aspects of utility performance that the commission wishes to monitor.

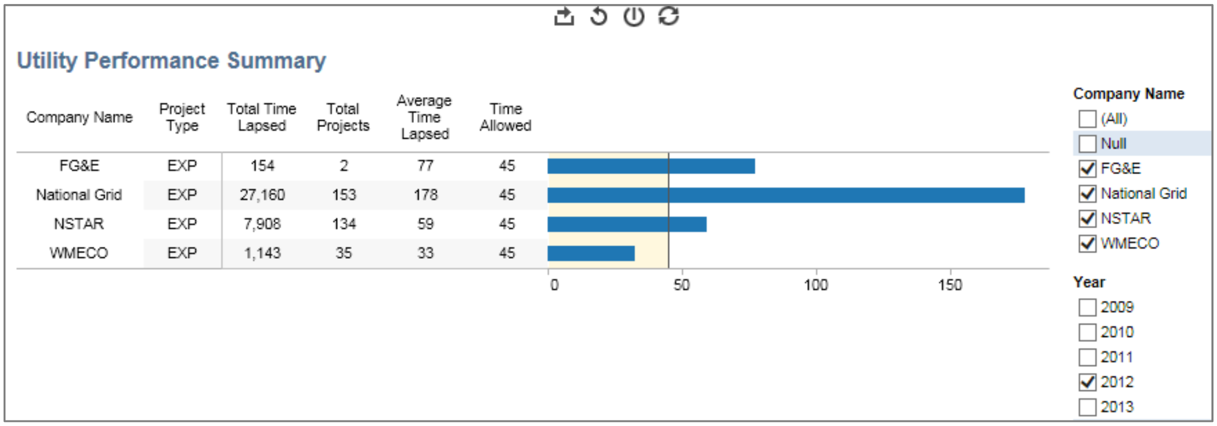
- **Up to Date:** The data and graphs should be updated frequently. Many metrics may warrant quarterly updates, while others should be updated at least on an annual basis.

The Massachusetts Department of Energy Resources' (MA DOER) interactive graphs regarding interconnection of distributed generation provide an example of how such data can be effectively displayed and communicated to stakeholders. For example, Figure 3 shows a screen shot of one of the interactive graphs. The text accompanying the graph states:

> This chart helps you answer the question "On average how are utilities performing with regard to expedited projects that have not received a supplemental review?" Similar to the metric used in the DPU-approved Timeline Enforcement Mechanism (DPU 11-75-F), the average time lapsed is accounted for by dividing the total utility work time lapsed by the total number of projects by utility. Please note that only expedited projects without supplemental reviews, but with an "Interconnection Agreement Sent" date, are included. The other project types are not represented in this chart.

Users can select different combinations of utilities and data years, and are able to export the graph and download the underlying data. The vertical line in the graph demarcates the maximum interconnection time allowed and enables users to quickly determine whether a utility is meeting the target.

Figure 3. MA DOER Interactive Dashboard on Distributed Generation Interconnection Time

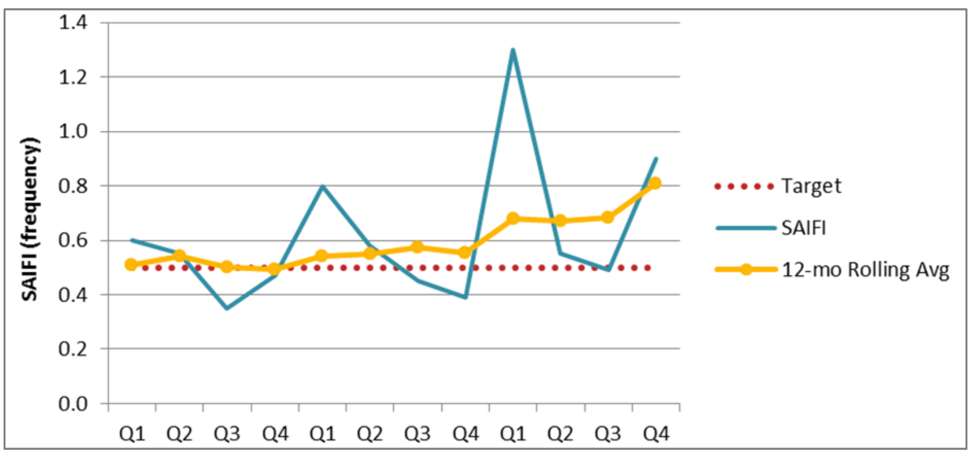


Company Name	Project Type	Total Time Lapsed	Total Projects	Average Time Lapsed	Time Allowed
FG&E	EXP	154	2	77	45
National Grid	EXP	27,160	153	178	45
NSTAR	EXP	7,908	134	59	45
WMECO	EXP	1,143	35	33	45

Source: Massachusetts Department of Energy Resources, Interconnection Utility Performance Summary Website. *https://sites.google.com/site/massdgic/home/interconnection/utility-performance-summary*[15]

Static graphs that display utility historical performance are also helpful. For example, the graph below presents hypothetical data for the frequency of utility outages, reported on a quarterly basis. Additional examples of data dashboards are provided in Appendix C.

Figure 4. Example Dashboard for Utility Outage Frequency



In sum, data dashboards can be an extremely useful tool for enabling regulators and other stakeholders to quickly review utility performance across a large number of performance areas.

[15] Note that although the interactive nature of the graphs is very helpful for comparing utility performance across years and utilities, the graphs appear to only display properly with Internet Explorer. In contrast, static graphs may have fewer technical issues.

4. PERFORMANCE TARGETS

A performance target defines the precise level of service or output that a utility is expected to achieve during a particular time period. Targets may be used simply to provide guidance for a utility, with neither penalty nor reward attached. Performance targets can also be used as the basis for providing a utility with a financial incentive to achieve desired outcomes.

4.1. Design Principles

The following design principles should be considered when setting performance targets:

1. Tie targets to regulatory policy goals
2. Balance costs and benefits
3. Set realistic targets
4. Incorporate stakeholder input
5. Use deadbands to mitigate uncertainty and variability
6. Use time intervals that allow for long-term, sustainable solutions
7. Allow targets to evolve

These principles are discussed more below.

Tie the Target to the Ultimate Policy Goal

Consider what level of performance is necessary to achieve policy goals, and state this explicitly. Doing so will help stakeholders evaluate whether performance targets are being set in a manner that moves toward achieving these policy goals and will help maintain momentum in that direction, while also allowing stakeholders to better determine when the underlying policy objective—as opposed to simply meeting the target—has been achieved.

Balance Costs and Benefits

Balance the costs to customers of achieving the target with the benefits to customers. Ratepayer surveys can help to identify ratepayers' priorities and how much they are willing to pay for higher levels of utility performance. For example, a 2010 survey of Ontarians found that 89 percent of residential customers were satisfied with current levels of electric reliability, and more than half of customers were not willing to pay more for increased reliability (Pollara 2010).

In theory, the optimal level of performance is obtained where the marginal benefits from improved performance are equal to the marginal costs of providing that increased level of performance. As explained by Baldwin and Cave,

> "as quality increases it becomes more expensive to raise it further; hence the marginal cost of quality improvement rises as quality rises. In contrast, as quality rises, the extra benefit consumers get from a further increase in quality declines. These two factors determine an optimal level of quality, where marginal benefit (to the customer) and marginal cost (to the utility company) are equal" (Baldwin and Cave 1999, 253).

Identifying the optimal level requires knowledge of both the utility's marginal cost curve, as well as customers' willingness to pay for different levels of reliability. Norwegian regulators have used surveys to construct a willingness to pay curve, and have internalized these values in the utility's decision-making process (see sidebar) (Growitsch et al. 2009). The Alberta Utilities Commission recently acknowledged the value of such customer willingness-to-pay surveys, but chose instead to rely on results from already-available customer satisfaction surveys to determine the acceptability of current levels of reliability for customers (Alberta Utilities Commission 2012).

In practice, especially for some performance areas, it may be difficult to quantify the marginal costs and benefits to determine the optimal performance target. In such cases, regulators may want to at least apply a qualitative assessment of what the costs and benefits to customers might be.

For example, if a commission were to establish a performance target related to the interconnection of distributed generation (in terms of average days for customer interconnection), it may be too burdensome to quantify all of the costs and benefits associated with reduced interconnection waiting time. Nevertheless, regulators, utilities, and others may be able to make a qualitative assessment of the value of increased distributed generation relative to the cost of reducing interconnection waiting time.

Balancing Reliability Costs and Benefits in Norway

Norway uses revenue cap regulation to provide a set amount of annual revenues to its electric utilities. Under this regulatory framework, utilities retain any savings achieved through cost reductions. This can create an incentive to cut costs at the expense of service quality. To combat this incentive, Norwegian regulators have internalized the costs of outages into the utility's profit-maximization function. This is done by adjusting utility revenues each year based on the costs of outages to customers.

If the utility reduces outages above a baseline level, it receives higher revenues the following year. In contrast, if outages increase, revenues are reduced. The amount of the increase or decrease in revenues is based on customers' willingness to pay for reliability, calculated separately by each customer sector. To maximize profits, the utility will increase expenditures up to the point where the marginal cost of increased reliability is equal to customers' willingness to pay (also referred to as the marginal benefit). The Norwegian utilities therefore face an incentive to provide the socially optimal level of reliability, where marginal costs are equal to marginal benefits.

Set a Realistic Target

The performance target should be realistically achievable by a well-managed utility. If utility performance is currently satisfactory, then the performance target could be set to simply maintain recent performance levels (assuming that future operating conditions will be similar to current conditions). If a higher level of performance is desired, a reasonable target can be developed based on (1) historical performance, (2) peer utility performance, (3) frontier methods such as data envelopment analysis, or (4) utility-specific studies.

1. Historical performance. Under the first method, a utility's previous performance over a set period of time—for example, the past ten years—is used to set the target. This method presumes that the data have been collected in the past and are readily available; that there has been little fundamental change in the key factors influencing utility performance; and that historical performance was satisfactory. Although historical data may be useful in setting initial performance targets, continuing to use historical data may be problematic due to the ratchet effect. The ratchet effect refers to the performance standard being raised if the utility performs well, making it harder for the utility to meet the standard in the next period, and diluting the incentive for the utility to improve performance in the current period (Comnes et al. 1995).

2. Peer utility performance. The second method uses peer groups to determine the performance target. If a peer group is used, effort should be made to account for the utility's unique circumstances that may impact the ability of the utility to reasonably achieve the target, or recent external factors that significantly impacted performance, such as a major storm.[16] This can be done through one of two ways: choosing a peer group that is similar to the utility in question, or using econometric techniques to control for certain variables.

   Direct comparison with peer utilities is referred to as "indexing." To identify the relevant group of peer utilities, econometric analysis can be performed to identify the most significant variables affecting utility performance, such as the geographic region and operating scale. Then utilities that are similar in these respects may serve as a suitable point of comparison. Another means of identifying a peer group is through cluster analysis, which groups utilities according to certain characteristics using statistical software (Shumilkina 2010).

   Where data on a variety of external factors that impact performance are available, econometric modeling can be used to control for these factors and provide an indication of "average" utility performance. However, the accuracy of the model is highly dependent upon inclusion of the correct variables and specification of the correct functional form (Shumilkina 2010). Failing to include data on a relevant variable can lead to omitted variable bias, yet collecting all of the relevant data (on utility characteristics, weather, age of investments, etc.) can be time consuming and prone to error.

3. Frontier methods. A third method of analysis is frontier analysis, a form of which is Data Envelopment Analysis (DEA). DEA measures technical efficiency of firms based on a sample of

[16] Although reliability reporting and performance targets generally exclude the impacts of major storms, the definition of "major storm" varies from state to state.

firms, their input use, and their outputs. The analysis identifies the most efficient firms and creates an efficiency frontier based on these firms' input usage per unit of output. Other firms are then assigned a score based on their efficiency relative to the efficiency frontier (Shumilkina 2010). Factors that are outside of a utility's control should be taken into account in the DEA analysis, but this is not easily done. This technique also suffers from a lack of internal validation, such as misspecification tests or goodness-of-fit statistics. Nevertheless, DEA analysis has been used by energy regulators to determine price and revenue requirements for utilities in Finland, Norway, the Netherlands, Germany, Austria, and Australia (Australian Competition & Consumer Division 2012).

4. Utility-specific studies. Finally, regulators can use utility-specific economic and engineering studies to set targets. For example, integrated resource plans may provide detailed cost and benefit information regarding certain resource investments under specific planning assumptions. Energy efficiency and demand response potential studies can identify the amount of investments that would be cost-effective for the utility to make. Production cost simulations have been used to model efficient dispatch, operation, and purchasing decisions, providing benchmarks against which utility performance can be measured.[17] These studies can help regulators identify and define specific resource investment targets and costs.

Regardless of the manner in which targets are set, regulators should minimize the ability of the utility to game target-setting. If there is an expectation that performance targets will be set at a future date based on historical data, the utility has an incentive to underperform until the target is set in order to establish a more lenient target. Econometric and frontier models can present challenges in terms of transparency, as these models are complex and require careful specification (Shumilkina 2010), which could lead to manipulation of the model to achieve the desired results.[18] Finally, basing targets on utility-specific studies that have been developed by the utility may create an incentive for the utility to overstate cost forecasts in order to deliver projects at costs that are below the target.

Incorporate Stakeholder Input

Allowing for meaningful stakeholder input during the process of setting targets is likely to result in targets that meet state regulatory goals, result in desired outcomes, and minimizes the potential for manipulating or gaming the targets. In addition, a meaningful stakeholder process can enable

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[17] San Diego Gas & Electric (SDG&E) operated under a generation and dispatch performance-based ratemaking (PBR) incentive plan from 1993 to 1997, and earned rewards during all three years that the plan was in operation. Year 1 and Year 2 awards were reported in SDG&E's *Electric Generation and Dispatch PBR Mechanism Final Evaluation Report*, April 1998, submitted pursuant to D.97-07-064 in A.92-10-017, and Year 3 awards were adopted in D.98-12-004 as part of the adopted settlement agreement.

[18] Econometric modeling requires that the modeler make a number of decisions regarding functional form, whether certain data points represent true outliers that should be excluded, whether to choose a model based on parsimony or goodness-of-fit, etc. These choices may all impact the final result and should thus be carefully reviewed.

stakeholder buy-in, and enhance the legitimacy of targets. Stakeholder input also reduces the likelihood of contentious disagreements once performance incentives are implemented and rewards and penalties start to be applied.

Energy efficiency performance standards sometimes use this approach, with good results. Some states have established advisory councils or collaboratives to help oversee and provide input to the efficiency program design and implementation, including the design and implementation of efficiency performance standards (e.g., Connecticut, Massachusetts, and Rhode Island – see sidebar). The stakeholders in these councils and collaboratives provide a considerable amount of input and review to the energy efficiency programs, which enables them to determine whether a particular performance incentive savings target is reasonable, or will be too easy or difficult to achieve. The stakeholders represent a broad range of views, including utility representatives, consumer advocates, environmental advocates, state agencies, and efficiency experts, which increases the chance that efficiency targets will be balanced and reasonable.

Stakeholder Engagement for Efficiency Standards

Efficiency councils have been established in Connecticut, Massachusetts, and Rhode Island—three of the leading states providing cost-effective efficiency programs. There are several key factors that make these three councils especially effective, including:

- *A broad representation of stakeholder interests.*
- *Frequent, well-organized meeting and communication systems to allow full access to information and debate.*
- *Efficiency experts available to provide technical support, with sufficient funding.*
- *Meaningful oversight by regulators, including a process where stakeholders can bring issues for resolution.*

Additional information is available at:

Connecticut - http://www.energizect.com/about/eeboard

Massachusetts - http://ma-eeac.org/

Rhode Island - http://www.rieermc.ri.gov/

Use Deadbands to Account for Uncertainty and Variability

Deadbands create a neutral zone around a target level in which the utility does not receive a reward or penalty. Deadbands can help to account for uncertainty regarding the optimal performance level, as well as allow for some performance variance based on factors outside of the utility's control (see sidebar for an example from Hawaii).

How large should deadbands be set? Deadbands are frequently set at one standard deviation of historical performance, but may be larger or smaller based on sample size and the tolerance for error. That is, if a large amount of historical data is available, then one standard deviation is likely to capture most of the normal variation in utility performance. If the sample size is small, for example three observations, then one standard deviation may not be large enough to capture the normal variation in utility performance. In such cases, a confidence interval can be constructed using the sample data and the regulator's desired level of confidence that the interval will sufficiently represent the range of normal variation.[19]

Use Time Intervals That Allow for Long-Term, Sustainable Solutions

The timeframe for measuring performance can impact the compliance strategies that the utility implements. If performance is measured only over a short timeframe, such as over one year, the utility has an incentive to implement solutions that can be quickly implemented, but may only have short-term benefits. In some cases, these short-run solutions may in fact be contrary to long-term sustainability. For example, a utility may be encouraged to compromise safety in order to achieve short-term economic goals.

In contrast, solutions that are optimal for the long-term may result in slow but steady improvement. For example, implementing sound maintenance and operational practices will result in long-term safety and economic benefits, but may not achieve short-term capacity factor targets. Thus performance measurements over the longer-term, such as the use of three-year rolling averages, may better encourage the utility to adopt sound long-term practices (NRC 1991).

Deadbands for Heat Rate Targets to Account for Integration of Renewables

Many states allow utilities to recover fuel and purchased power costs through automatic pass-through mechanisms. To ensure that utilities retain an incentive to operate their power plants efficiently, some states have conditioned fuel cost recovery upon power plant performance factors. For example, Hawaii's Energy Cost Adjustment Clause (ECAC) contains a heat rate efficiency factor.

Although Hawaii's ECAC encourages maintaining the thermal efficiency of thermal generators, concerns were raised that the fixed sales target heat rate would penalize the utilities for introducing renewable energy, as lower capacity factors and higher ramping requirements can negatively impact thermal units' heat rates. In order to avoid the resulting disincentive for efficiency and renewable energy, a deadband of +/- 50 Btu/kWh sales was added to the heat rate target, and an agreement was reached to revisit the heat rate target upon the future addition of larger increments of renewable resources.

See HECO Final Revised Tariff Sheet Nos. 63-63E, filed on July 24, 2012, in Docket No. 2010-0080

Allow Targets to Evolve

In general, once a target is set, it should be adjusted only slowly and cautiously in order to provide utilities with the regulatory certainty required to make long-term investments. However, targets may need to evolve over time for two reasons. First, if performance needs to be improved, it may not be possible for the utility to immediately achieve the desired level of performance, as noted above. Some problems may take years to fully remedy, despite the utility undertaking immediate actions to remediate the situation. In such cases, the performance measurement time interval can be lengthened, or targets can be set to become more stringent over time, providing the utility with a glide path for achieving the ultimately desired level of performance.

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[19] For more information on this approach, see Lowry et al. 2000.

Second, a target may need to evolve over time as technologies and policy goals evolve, or as the operating environment changes significantly. For example, smart grid investments may be able to dramatically improve outage duration rates. Therefore, if a utility makes significant investment in new smart grid technologies, then any reliability performance targets for that utility should be reviewed, and perhaps modified, to reflect the implications of the new technologies.[20]

[20] In addition, if the utility is using improved reliability as part of the justification for such smart grid investments, then the performance targets can be used to ensure that those benefits are actually achieved.

5. Financial Rewards and Penalties

5.1. Design Principles

Once performance targets have been defined, regulators can establish incentives to further induce the utility to accomplish the desired outcomes. Rewards and penalties are generally financial in nature, although other forms of incentives may be used.[21]

The following design principles should be considered when setting financial rewards and penalties:

1. Consider the value of symmetrical versus asymmetrical incentives
2. Ensure that any incentive formula is consistent with desired outcome
3. Ensure a reasonable magnitude for the incentive
4. Tie incentive formula to actions within the control of utilities
5. Allow incentives to evolve

Value of Symmetrical versus Asymmetrical Rewards and Penalties

Financial incentives are frequently designed to be symmetrical, in order to provide balance and to both discourage poor performance and encourage exemplary performance. Symmetrical incentives generally also mirror more closely how a utility would be compensated in a competitive environment. However, in some cases asymmetrical incentives may be more appropriate than symmetrical ones.

Penalty-only incentives may be appropriate when the outcome is either an essential requirement for the utility, or when performance above target outcomes provides little additional benefit to ratepayers. For example, customers might not be willing to pay for incremental improvements in reliability beyond the target level, particularly if customers would be required to pay for any reliability improvements through both rates (to recover utility expenses) and performance rewards. At the same time, utilities have a clear obligation to provide sufficient levels of reliability, therefore unsatisfactory performance might

Asymmetrical Incentives in Alberta

In a 2012 order, the Alberta Utilities Commission rejected providing utilities with a positive performance incentive for exceeding service quality, writing "…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" (Alberta Utilities Commission 2012, 194–195).

[21] For example, the UK allows expedited regulatory treatment of utility business plans for business plans that are well executed. This offers utilities the benefits of reduced regulatory burdens and risks. In addition, the UK uses "reputational" incentives, where utilities' success in reducing carbon emissions is compared and made publicly available.

warrant the applications of penalties. See the sidebar for an example of asymmetrical incentives in Alberta.

In other cases, it may be beneficial to administer incentives on a positive basis only. This is common for energy efficiency incentives where any megawatt-hour of energy saved through a cost-effective efficiency program results in a benefit to ratepayers. In addition, reward-only incentives tend to encourage utilities to be more innovative, and may result in more collaborative and less adversarial processes (NY PSC 2012).

Ensure Incentive Formula Is Consistent with Desired Outcome

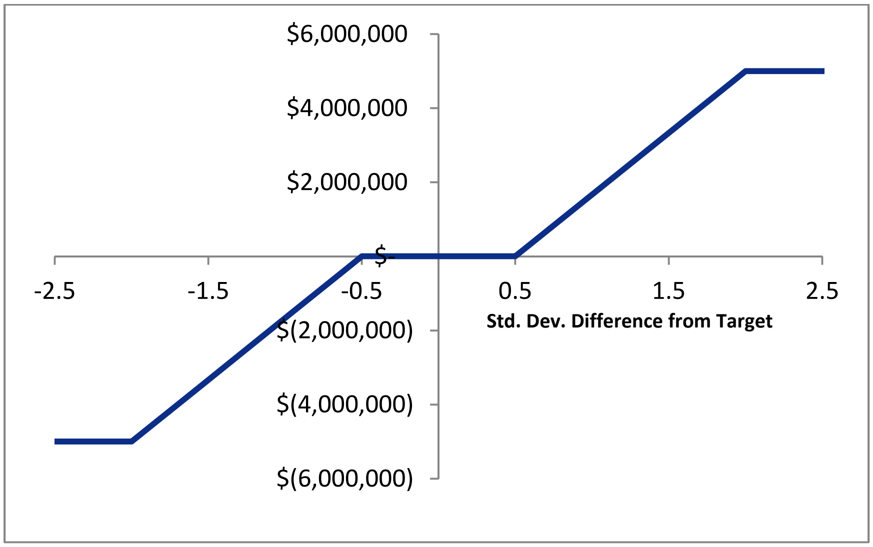
Incentive formulas can take numerous forms, including linear, quadratic, and step functions. It is important that the formula (and the shape and slope) of the incentive is consistent with the desired outcome and supports appropriate utility performance. The shape and slope of the formula determine how quickly the curves reach the maximum reward or penalty as performance deviates from the target (or the ends of the deadband). Below we present several possible incentive formulas and some of their benefits and drawbacks. Each graph shows how rewards or penalties (vertical axis) change as performance deviates from zero to two standard deviations from the target.

Linear Function with Deadband

Figure 5 depicts an incentive formula that has a deadband of 0.5 standard deviations, measuring how much performance varies from the average, on either side of the target. After 0.5 standard deviations, penalties and rewards increase in a linear fashion up to a maximum of $5 million. This formula is simple to understand and administer, and the deadband helps to control for normal fluctuations in performance due to factors that are outside the control of the utility.

A potential drawback is that a utility may be induced to perform at a level close to 0.5 standard deviations below the target, since such under-performance would not result in a penalty. The utility would especially have an incentive to operate close to -0.5 standard deviations from the target if the target is based on a rolling average of historical performance. This highlights the importance of monitoring utility behavior and making adjustments as necessary, such as narrowing the deadband over time, or delinking performance targets from historical performance.

Figure 5. Hypothetical Linear Formula with Deadband



<u>Quadratic Function</u>

A quadratic function (also referred to as a "parabolic function") can also be designed to provide increasing rewards or penalties as performance deviates from the target, but the rewards or penalties increase more slowly. Figure 6 presents a simple linear incentive function, as well as a quadratic incentive function with the same end points and central target.[22] As indicated, a quadratic formula acts similar to a deadband by providing little incentive near the central target. A quadratic function also results in an increasing slope as the performance deviates from the performance target.

Massachusetts has used a modified quadratic formula since 2001. In its order approving the formula, the Department of Public Utilities wrote: "While a linear formula may have the perceived advantage of simplicity, the Department considers a non-linear formula provides a stronger link between a utility's performance and the consequences of it failing to meet [service quality] measures" (MA DPU 2000, 25).

The formula for the quadratic function uses four inputs:

- Maximum reward or penalty (e.g., $5,000,000)
- Actual utility performance (e.g., a score of 1.75)
- A target (e.g., a score of 1.0)
- The standard deviation, σ (e.g., 0.5)

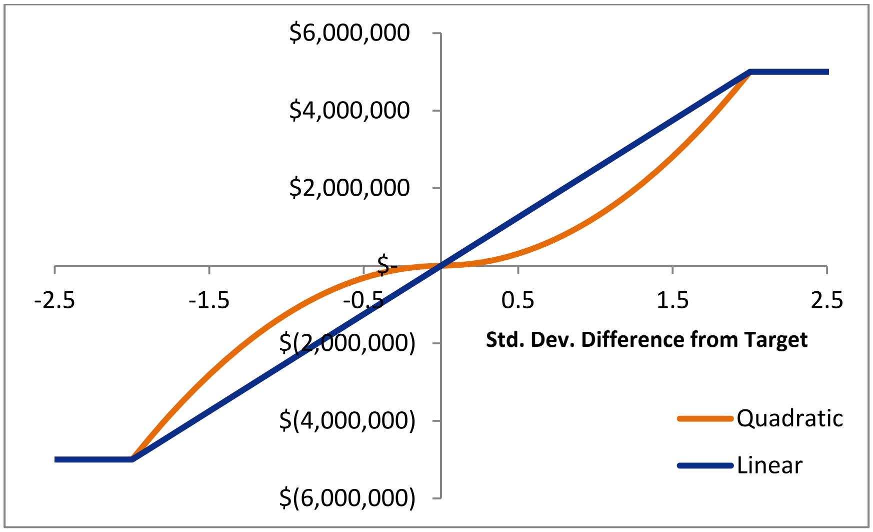
Penalties and rewards are maximized at two standard deviations from the target. A scalar of 0.25 is used to constrain the scores to values between 0 and 1, which is then multiplied by the maximum incentive.

[22] A linear function does not square the standard deviation difference from the target and uses a scalar of 0.5.
Reward or penalty = [(performance – target)/σ] x (0.5) x (maximum reward or penalty)

Reward or penalty = $[(\text{performance} - \text{target})/\sigma]^2 \times (0.25) \times (\text{Maximum reward or penalty})$

Using the example values from above: $[(1.75 - 1.0)/0.5]^2 \times (0.25) \times \$5{,}000{,}000 = \$2{,}812{,}500$

Figure 6. Quadratic Function Compared to a Linear Function

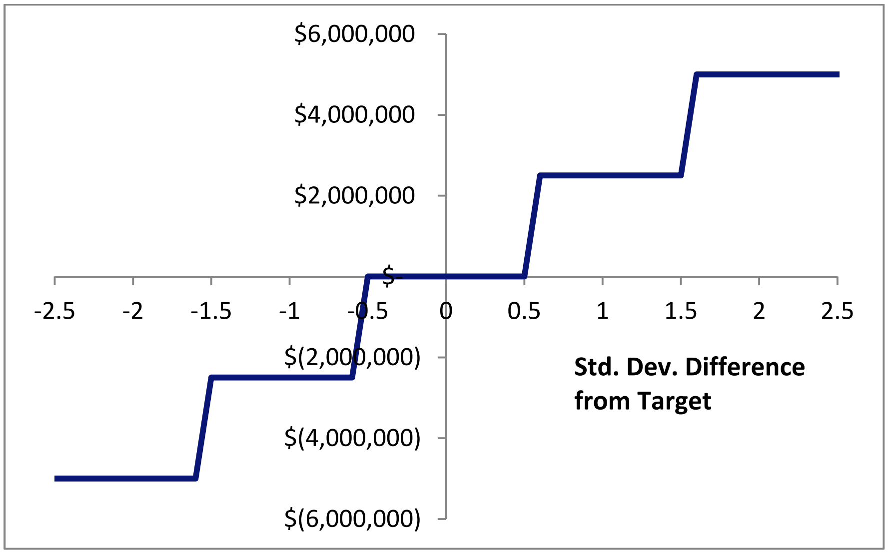


<u>Step Functions</u>

Step functions can be simple (e.g., two steps), or complex (multiple steps). Either way, the utility receives no incentive until it reaches a certain level of performance, at which there is a sharp change in the reward or penalty it receives. For example, in Figure 7 the utility receives no reward until it performs at 0.5 standard deviations above the target, at which point it receives a reward of $2.5 million. It continues to earn only $2.5 million until performance reaches 1.5 standard deviations above the target, at which point the reward increases to the maximum of $5 million.

Step functions are common and can be easy to administer, but they have several important drawbacks. When the amount of the penalty or reward can change dramatically with only a small change in performance (e.g., when performance increases from 0.49 standard deviations to 0.5 standard deviations from the target), the performance evaluation process can become very contentious. In addition, such sharp thresholds may induce a utility to engage in unsafe or unsound practices in order to avoid a large penalty or receive a large reward.

Figure 7. Hypothetical Step Function



Ensure a Reasonable Magnitude for the Incentive

When establishing the appropriate magnitude of financial incentives, regulators should generally seek to balance two competing objectives. Financial rewards and penalties should be large enough to capture utility management's attention and provide sufficient motivation to reach the desired outcome. On the other hand, rewards and penalties should not be disproportionate to the costs and benefits of the desired outcome. The reward should not unduly reward or penalize the utility, and rewards should not offset the benefits to ratepayers.

Performance incentive mechanisms should include a cap on the maximum penalty or reward, in order to ensure that the magnitude of the incentive will remain within a reasonable bound. Regulators should also consider the size of rewards and penalties within the context of the magnitude of existing incentives to ensure existing incentives and new incentives are properly balanced.

For utilities that are provided with multiple performance incentives, it is important to consider the potential impact on the total reward or penalty that might be applied. The total financial impact on a utility will depend on both the magnitude of the rewards and penalties and the likelihood of being assessed those rewards and penalties.

When establishing the magnitude of financial rewards and penalties, regulators may also need to consider the particular financial circumstances of the utility involved. This becomes especially important if the magnitude of the combined penalties and rewards are large enough to significantly impact the utility's financial position. Financial analysts and utility management typically pay special attention to the utility's financial position, thus it is important to recognize the financial implications of the penalties and rewards. This may involve several considerations:

- Financial analysts typically assess the risk associated with utilities, as well as the risk associated with regulatory systems and new regulatory measures. Therefore, it is important that the performance incentive mechanism and the potential financial impacts are clearly defined and transparent.

- Many utilities motivate managers and employees with incentive systems based upon stock options and prices. If the performance incentives have a significant effect on stock prices, then this provides additional, personal incentives to those employees to help meet performance goals.
- One thing that might help place the magnitude of rewards and penalties in perspective is to present them in financial terms, such as in terms of basis points on the return on equity, or in terms of equivalent cents per share on utility stock prices. Presentation of financial incentives is discussed briefly in the subsection below.

Further, rewards and penalties should always be proportionate to the importance of the performance goal to ratepayers. In general, incentive payments should not exceed the net benefits to ratepayers.

Presentation of Financial Incentives

Rewards and penalties can be expressed in several different equivalent units to help place their magnitude in context. For example, they can be presented as dollars, cents per share, basis points of return on equity (ROE), percent of non-fuel operating expenses, percent of base revenues, or percent of total earnings. The table below demonstrates how an incentive amount of $2.5 million could be presented in order to help stakeholders understand the magnitude of the incentive in relation to the utility's return on equity, operating expenses, cents per share, and percent of earnings. Total earnings can also be shown to provide context.

Table 15. Hypothetical Presentation of Financial Incentives in Different Units

Maximum Reward or Penalty	Equivalent Basis Points	Equivalent % of T&D Revenues	Equivalent cents/share	Percent of Pre-Tax Earnings	Total Pre-Tax Earnings
$2,500,000	25	0.9%	2.47	3.1%	$80,645,000

Presenting financial rewards and penalties in multiple units is useful during the process of setting the financial incentives. However, administration of the incentives is generally simplest when done as dollars, as other units can be administratively complex and result in perverse incentives. For example, positive incentives that are set in terms of ROE basis points could provide an incentive for a utility to increase rate base. See Appendix A for an example of the perverse impacts of an ROE adder for certain investments.

Tie Incentives to Actions and Outcomes within the Control of Utilities

Financial incentives should be based upon actions and outcomes that are within the control of the utility. First, if an action or outcome is beyond the control of the utility, then the performance incentive would have little to no effect on achieving the desired outcome, and therefore should not be applied at all. Second, it is unfair for customers to pay for utility rewards that are not a result of utility actions. Third, it is unfair to penalize utilities for outcomes that are beyond their control.

While this principle seems obvious and important, it can be difficult to hold to it in practice for some performance areas and metrics. Some events might be beyond a utility's control (e.g., the incidence and types of severe storms), but there may be things a utility can do to mitigate the implications of those events (e.g., by having effective emergency preparedness and emergency response programs).

Some elements of utility performance might be beyond a utility's control but may appear to be reasonable to include in an incentive formula. For example, some states have established "shared savings" incentives, where utilities are allowed to keep a small portion of the savings that they achieve as a result of improved power plant performance. This approach makes intuitive sense because customers can be expected to experience only net benefits as a result of the incentive, and ideally the majority of the net benefits. However, the magnitude of the savings from such incentives is often based on avoided fuel costs, which can fluctuate wildly for reasons completely beyond the control of the utility. As a result, utilities can experience undue windfalls or penalties. (See Appendix A for a discussion of the financial incentive for the Palo Verde nuclear power plant, which was based on avoided power costs. These avoided costs, and thus the financial incentive, skyrocketed during the California Energy Crisis in 2000).

In some instances it may be appropriate to provide financial incentives for actions that are only partly within a utility's control. For example:

- Regulators could provide all utilities in a multi-utility state with rewards if a statewide energy efficiency goal is met. A reward based on achievement of a statewide goal has two effects: (a) it encourages utilities to work together and share best practices; and (b) it provides an incentive for utilities to continue to pursue the statewide goal, even if they are clearly not going to meet their individual utility target.
- Regulators could provide utilities with rewards for supporting other initiatives regarding efficiency standards, building codes or commercialization of clean energy technologies. Utilities can have a significant influence on such statewide initiatives, even if they are partly or mostly beyond their control.
- Regulators could provide utilities with rewards for achieving certain energy policy, public interest, or societal goals that are partly beyond utility control, such as reducing the fuel burden on low-income customers or meeting economy-wide pollution targets.

Allow Incentives to Evolve

As with other aspects of performance incentive mechanisms, financial incentives may need to be adjusted over time. Financial incentives are sometimes adjusted when the magnitude of the incentive is found to be unreasonably large or small, or the basis for the financial incentive (e.g., avoided fuel costs) is found to be excessively volatile, resulting in excessive penalties or rewards.

Excessive penalties and rewards can sometimes be addressed easily, such as with a cap on rewards or penalties. In other cases a correction might require fundamental redesign of the incentive mechanism, including a full stakeholder process. While regulators should expect performance incentives to evolve over time in response to lessons learned in practice, it is also important to make any adjustments cautiously in order to preserve regulatory transparency and certainty to the greatest extent possible.

In order to avoid the possibility of overcompensation, it is advisable to begin with small financial incentives and adjust these gradually upward over time if needed. In some cases, a small financial incentive may be all that is needed in order to induce the utility to achieve the desired result, thus preserving the majority of benefits for ratepayers.

An incremental approach also allows utilities and regulators to gain experience with an incentive mechanism and manage any unforeseen consequences of the incentive without large impacts on ratepayers. As parties gain more confidence that the performance incentive mechanism does not suffer from any major flaws, the amount of compensation can be increased if needed.

5.2. Rewards and Penalties in the Context of New Regulatory Models

Several recent proposals for new regulatory models emphasize the goal of rewarding utilities for performance and desired outcomes. For example, a utility-stakeholder collaborative group in Minnesota writes:

> As its name suggests, a performance-based approach would tie a portion of a utility's revenue to achieving an agreed-upon set of performance metrics (e.g., measuring such things as energy efficiency, customer service, environmental sustainability, affordability, and competitiveness) so that utilities have a natural financial incentive to produce the outcomes customers want (e21 Initiative 2014, 3).

The RIIO model that is being developed and applied in the UK includes financial incentives that are roughly equal to 5 percent of utility revenues (see Appendix A). This is considered to be a relatively large portion of utility revenues to dedicate to financial incentives, and we are not aware of any states or countries that apply larger financial incentives.

Whether a set of performance incentives will result in "a natural financial incentive to produce the outcomes customers want" will clearly depend upon many factors, such as the type and scope of the outcomes targeted, the performance metrics, the targets chosen, the amount and type of financial incentives, and more. One of the key factors likely to determine how well the combination of incentives will lead to desired outcomes is the amount of money that is at stake. As described in Chapter 2, utilities already have many different financial incentives, some of which are aligned with customer interests, some of which are not. These existing financial incentives are very influential and exist in every regulatory context.

In thinking about new regulatory models, one key question that regulators should ask is: Will the set of new performance incentives be sufficient to modify, or at least balance against, the financial incentives of the existing regulatory model? Regulators should compare the magnitude of the proposed performance incentives with the magnitude of existing financial incentives. If new regulatory models are to result in a fundamental shift of incentives away from capital investments and toward performance outcomes, then the magnitude of the financial rewards and penalties will need to be significantly larger than the amounts used to date in the United States, and may need to be larger than under the RIIO model used in the UK, discussed below.

In addition, new regulatory models will need to reduce the incentive that utilities currently have to increase their rate base. This could be achieved by reducing, or eliminating, the amount of profit that a utility earns from rate base, and replacing that amount of profit with revenues from performance incentives.[23] Ultimately, the combined impact of modified equity recovery plus financial incentives should meet the standard criterion of allowing the utility to recover prudently incurred costs plus an opportunity to earn a reasonable return on equity. In this case the opportunity to earn a reasonable return on equity would be based primarily, or entirely, on utility performance relative to the performance incentives.

When designing new regulatory approaches for utilities to recover revenues, regulators must also be cognizant of the implications for utility financial positions. First, utilities must be able to maintain a reasonable financial position for a reasonable level of performance. Second, as noted above, managers and analysts need to be able to assess the risk associated with new regulatory mechanisms, and shifting the sources of revenues could easily change the risk profile of a utility's financial position.

It may also be important to consider the timing of revenue recovery. If the recovery of equity costs is partially replaced by the recovery of performance incentives, then the timing should be properly aligned. Currently utilities are allowed to recover equity and debt costs over the full book life of a capital asset. If the financial incentives are recovered over a shorter time period, then there might be a misalignment of when customers experience the benefit and when they are charged for it. On the other hand, performance incentives typically work best when the rewards and penalties are applied relatively close in time to the performance outcomes themselves.

An Example: the RIIO Model

The UK's RIIO model bases a large amount of a utility's earnings on its performance. As detailed in Appendix A, potential rewards and penalties associated with environmental, customer satisfaction, social obligations, and connections performance incentive mechanisms equate to approximately 3 percent of utility annual base revenues. Reliability-related rewards and penalties carry with them the possibility of an additional 250 basis points in rewards or penalties. The results of Ofgem's modeling suggest that utilities' realized return on equity may fluctuate by approximately +/- 300 basis points due to these performance incentive mechanisms (Ofgem 2014b).

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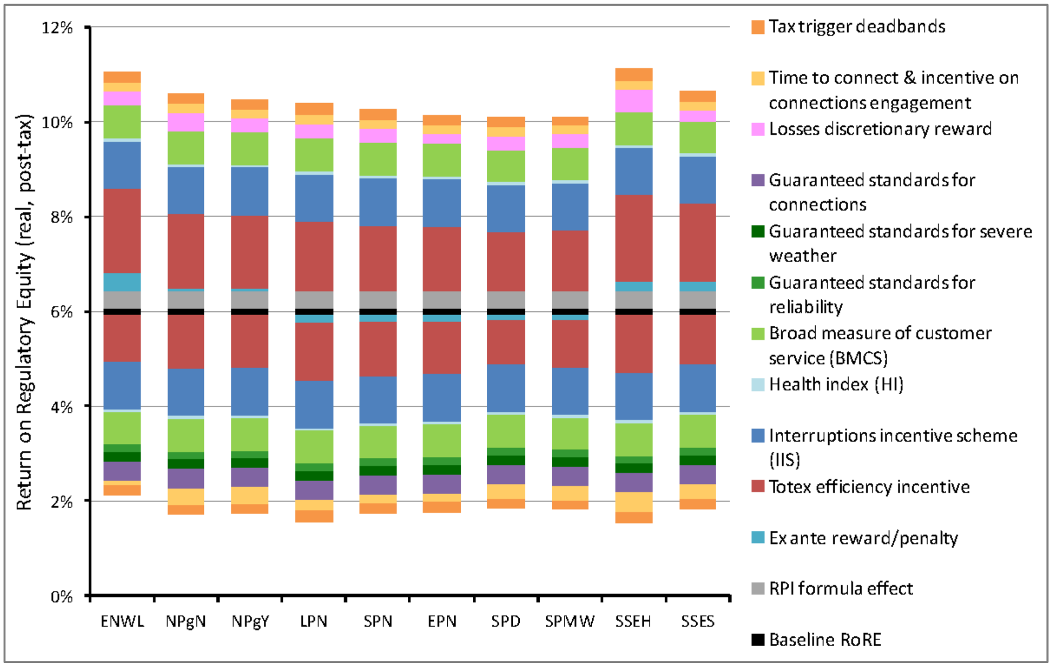
[23] Under RIIO, capital expenditures and operating expenditures are combined into one category: "total expenditures," or "totex." The utility then earns a return on a pre-determined portion of totex, regardless of whether the utility's capital expenditures are higher or lower than that amount. This treatment seeks to balance the incentive to invest in capital versus non-capital projects.

These performance incentive mechanisms are part of a revenue cap plan that provides for annual revenue increases at the rate of inflation and allows utilities to retain a large portion of any cost savings they achieve. Allowed revenues are set using a 6 percent return on equity, but actual earnings may vary significantly based on utility performance. According to Ofgem's modeling, the actual ROEs for "slow-track" utilities are likely to range from approximately 2 percent to more than 10 percent, as shown in the figure below (Ofgem 2014b).

Figure 8. Plausible ROE Range for UK Distribution Utilities



Source: Ofgem 2014b, page 46

This wide variability of potential utility returns is by design, as Ofgem determined early on that high-performing utilities should have the opportunity to earn an ROE of greater than 10 percent, while poorly performing utilities could earn an ROE of less than the cost of debt. Ofgem notes that the results shown in the figure above indicate that the package of risk and incentives has been "appropriately calibrated" (Ofgem 2014b, 46). The relatively large magnitude of incentives under RIIO not only helps to focus management attention on the attainment of the established targets, but may also help to provide the revenues necessary for innovating and implementing new technologies.

6. IMPLEMENTATION

6.1. Questions to Help Inform Regulatory Action

Regulators may wish to ask themselves, as well as relevant stakeholders, several questions that would help inform their decisions on whether and how to proceed with performance metrics and incentives. For example:

1. **How well does the existing regulatory framework support utility performance?**

   Are the utilities already achieving standard regulatory goals, such as providing low-cost, safe, reliable service? Are there specific areas of performance where utility performance has been questionable, or where customers have raised complaints? What activities or investments are currently the key profit centers for the utilities?

2. **How well does the existing regulatory framework support state energy goals?**

   What are the priority state energy policy goals, and how well do the utilities achieve them? These may include a variety of goals related to costs, reliability, clean energy resources, grid modernization, customer protections and more. Regulators should recognize that policy goals may evolve, and may require different incentives and regulatory models over time.

3. **What are the policy options available to improve utility performance?**

   As described in Chapter 2, there are many regulatory policies that will provide utility incentives and influence utility performance. Regulators may wish to modify or implement any of these other policy options in concert with, or in lieu of, performance metrics and incentives.

4. **Is the industry, market, or regulatory context expected to change?**

   If change is expected to occur, utilities may benefit from additional regulatory guidance regarding the preferred response, or may require additional incentives that were not necessary previously. There may also be emerging policy goals that the commission wishes to emphasize.

5. **Does the commission prefer to oversee investments, or to guide outcomes?**

   Traditional regulation typically allows regulators to oversee the utility investments and activities that are intended to achieve desired outcomes (e.g., during a rate case). In contrast, performance metrics and incentives allow regulators to provide more guidance on the desired outcomes, and less guidance on the means to achieve them.

6. **Does the commission wish to specify the outcomes in advance?**

   Traditional regulation typically allows regulators to oversee major capital investments and review expenses after the costs are incurred (typically during a subsequent rate case). As a result, there is little regulatory guidance provided before investments are made, at a time when alternative actions or investments can be considered. Integrated resource planning, where it is practiced, provides an exception to the common practice that regulation only takes place after the fact, after the money has been invested or spent. Performance metrics and incentives, on the other hand, provide greater regulatory guidance up front, and are therefore more likely to influence the outcomes.

The answers to these questions will help regulators determine what level of performance regulation is appropriate for their jurisdiction, and what type of performance metrics and incentives to implement.

6.2. Implementation Steps

Once a determination has been made to implement performance metrics or incentive mechanisms, the following steps can be implemented. These can be implemented incrementally, to allow for each step to inform the subsequent step, or they can be implemented several steps at a time, or all at once.

1. <u>Articulate goals</u>**.** The first step is to identify and articulate all the energy policy goals that are applicable to utility regulation, whether the goals are current or anticipated.

2. <u>Assess current incentives</u>**.** Next it is critical to assess and understand the financial incentives, including those in place within company management and provided by utility interactions with investor analysts, which are created by the current or anticipated regulatory, management, and financial context. Performance incentives should then be designed to modify, balance or supplement these existing incentives. (See Chapter 2.)

3. <u>Identify performance areas that warrant performance metrics</u>**.** These performance areas may include traditional performance areas or new and emerging performance areas, depending on the needs of the particular jurisdiction. (See Chapter 3.)

4. <u>Establish performance metric reporting requirements</u>**.** Use performance metrics to monitor those areas identified in Step 3. Review the results over time to identify any performance areas that may require targets. (See Chapter 3.)

5. <u>Establish performance targets, as needed</u>**.** Establish targets to provide utilities with a clear message regarding the level of performance expected by regulators. Review the results over time to determine whether any performance areas warrant rewards or penalties. (See Chapter 4.)

6. <u>Establish penalties and rewards, as needed</u>. Establish reward or penalties to provide a direct financial incentive for maintaining or improving performance. (See Chapter 5.)

7. <u>Evaluate, improve, repeat</u>. Creating effective performance incentive mechanisms is an iterative process. The effectiveness of the mechanisms should be monitored closely and evaluated to determine which aspects are working well, and which are not. Targets, financial incentives, and other components of the mechanisms may need to undergo several adjustments before they achieve their full potential. (See Section 6.4)

6.3. Pitfalls to Avoid

No performance incentive mechanisms can be said to be perfectly designed, but those that work well succeed in providing greater benefits than costs to all parties. Unfortunately, there are also many examples of performance incentive mechanisms that have not succeeded, for a variety of reasons. Below we address some common pitfalls that regulators should endeavor to avoid when designing performance incentive mechanisms.

Disproportionate Rewards (or Penalties)

Performance incentive mechanisms can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the desired outcome. Rewards (or penalties) can also be unduly high if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.

It is critical that regulators avoid the pitfall of over-rewarding utilities for performance. When utility rewards exceed the benefits to customers, particularly when they are first implemented, the entire concept of incentive mechanisms is undermined. Higher-than-expected rewards can also result in substantial backlash against performance incentive mechanisms that might have otherwise worked well.

Potential Solutions

One way to avoid this pitfall is for regulators to adopt an incremental approach: begin with small rewards and monitor and adjust over time. Another option is to establish caps on rewards (and penalties), to ensure that they stay within reasonable bounds.

Avoided Costs and Disproportionate Rewards

To encourage improved nuclear power plant performance, California implemented incentive payments for electricity produced by several of its nuclear reactors. In 1988, a settlement established the payment rate for electricity produced by Diablo Canyon, based on then-current avoided costs of fossil generation. This rate was to remain fixed, escalated only for inflation. By the mid-1990s, Diablo Canyon was earning more than $0.12/kWh, while Western Market wholesale power prices were approximately $0.03/kWh.

Later, a similar performance incentive mechanism was established for Palo Verde Nuclear Generating Station, but in this case the payment was set at the avoided cost of replacement power. Unfortunately, by the summer of 2000 the California energy crisis was in full swing, and the cost of replacement power had increased more than ten-fold. Again, the volatility of the markets had resulted in utility rewards much higher than intended. Both of these performance incentive mechanisms were subsequently modified, and further details can be found in Appendix A.

Another tool that can help prevent excessive compensation to utilities for some PIMs is shared savings. For example, when a utility implements a cost-saving measure, shared savings mechanisms pass on a portion of utility profits to ratepayers. Again, it is advisable to begin with a shared-savings mechanism that passes most profits to ratepayers, and reduce this proportion over time if needed in order to provide the utility with greater incentives.[24]

Unintended Consequences

Perhaps the most challenging aspect of designing performance incentive mechanisms is anticipating and avoiding unintended consequences. A common effect of establishing an incentive for one aspect of utility performance is to shift management's attention to the areas with incentives, to the detriment of areas that do not have incentives.

Unintended effects can also result from failing to recognize the linkages between various aspects of the utility's system. For example, providing an incentive for achieving high capacity factors at certain utility power plants could create several perverse incentives, such as encouraging the utility to: (1) increase sales, (2) operate units out of merit order, (3) engage in otherwise uneconomic off-system sales, or (4) defer needed maintenance outages.

Potential Solutions

Avoiding unintended consequences requires significant attention to the myriad incentives utilities face and the ways in which the performance target may influence other aspects of the utility's system. Strategies to minimize negative impacts include:

- Implement a diverse, balanced set of incentives to avoid concentrating management attention on only one area.
- Focus on performance areas that are relatively isolated from others, where possible. Energy efficiency is a good example of an area that may have relatively little impact on other aspects of utility performance.
- Explicitly assess up front how performance standards might influence other performance areas that do not have standards. Solicit input from multiple stakeholders and learn from experiences in other states.
- Allow for performance incentives to evolve over time to correct for unintended consequences.

Regulatory Burden

[24] Shared-savings mechanisms can also be structured to give a greater proportion of early savings to one of the parties (either shareholders or ratepayers), and a smaller proportion of later savings to that same party. A regressive sharing mechanism gives more of the early savings to shareholders, but less of the later savings. A progressive savings mechanism works in reverse by providing more of the early savings to ratepayers. An advantage of the progressive shared savings mechanisms is that it protects ratepayers against uncertainty, since if the performance target is miscalculated and set too low, ratepayers still retain a large portion of the savings. Progressive sharing mechanisms also create a stronger incentive for the utility to achieve high levels of savings. However, if the target is set where it is already difficult for the utility to meet and already delivers significant value to ratepayers, a regressive mechanism may be appropriate for equity reasons. For more discussion, see Testimony of William B. Marcus, PBR Economic Issues, JBS Energy, in California PUC Docket A. 98-01-014, July 3, 1998.

If performance incentive mechanisms are not designed well they can be too costly, too time-consuming, or too much of a distraction, for the utility, the regulators, and other stakeholders. Data reporting and verification can be resource intensive. Determining appropriate targets can be time-consuming and contentious, and disputes over penalties can be expected, particularly when large sums of money are at stake. These activities can divert limited resources away from more important issues, becoming an unnecessary distraction.

> ***Reducing Regulatory Burden in New York***
>
> *In 2012, the New York Public Service Commission issued an order that abolished the penalty portion of energy efficiency incentives. The Commission's experience was that the threat of penalties "created an adversarial approach to setting targets and budgets, undue aversion to risk, and short-term allocation of resources that may not serve the long-term interests of a balanced program." In addition, consideration of mitigating circumstances presented a substantial drain on staff and utility resources that could have been better spent on administering programs. See NY PSC 2012, 5-6.*

<u>Potential Solutions</u>

To avoid unnecessary regulatory burden, regulators should endeavor to streamline performance incentive mechanisms by using existing data and protocols where possible, and relying on simple mechanism designs. If a specific PIM is becoming a distraction, it may be because too much money is at stake. Ensuring that the reward or penalty is commensurate with the importance of the policy goal will help to ensure limited resources are appropriately allocated.

Uncertainty

Metrics, targets, and financial consequences that are not clearly defined create uncertainty, introduce contention, and are less likely to achieve policy goals. In addition, significant and frequent changes to incentives create uncertainty for the utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short-term solutions.

<u>Potential Solutions</u>

A critical step in reducing uncertainty is to carefully specify metric and target definitions, soliciting utility and stakeholder input where possible. If historical data are available, it can be instructive to use such data to provide examples of how the performance data will be assessed and rewarded or penalized in the future. As discussed in the case study in Chapter 3, such an approach may have helped Nevada utilities and stakeholders avoid much of the litigation and controversy regarding whether a certain type of facility would be designated as a "critical facility" eligible for enhanced return on equity.

The speed with which performance metrics and incentives are reported and applied can help reduce uncertainty. Information regarding the achievement of targets and the magnitude of incentives should be provided as quickly as possible, to minimize uncertainty and allow for mid-course corrections as soon as possible.

Regulatory certainty is equally important for ensuring that long-term utility investments are made efficiently, and incentives are not diluted. To this end, regulators should adjust targets and financial consequences only cautiously and gradually so as to reduce uncertainty and encourage utilities to make investments with long-term benefits.

Gaming and Manipulation

Every performance incentive mechanism carries the risk that utilities will game the system or manipulate results. "Gaming" refers to a utility taking some form of shortcut in achieving a target so that the target is reached, but not in a way that was intended. For example, if a performance incentive were set that rewarded a utility for increasing a power plant's capacity factor above a certain threshold, the utility might understandably respond by increasing its off-system sales from that power plant, even at an economic loss. Thus the utility would be able to meet or exceed the target capacity factor, but ratepayers would be worse off.

Manipulation of the results refers to the deliberate alteration or obscuring of unfavorable performance data, whether through use of dubious analysis methods, improper data collection techniques, or direct alteration of data. An example of this occurring in California is provided in Appendix A, as well as in a call-out box in Chapter 3.

<u>Potential Solutions</u>

The ability of utilities to game an incentive typically points to the need to refine how a metric is defined. In the example above, the metric could be redefined to exclude energy sold at a loss or energy from a unit that is operated out of merit order. This pitfall can be quickly remedied by ensuring that regulators carefully monitor how well performance incentive mechanisms are achieving their intended results, and step in quickly to make necessary adjustments, particularly where an incentive is clearly being gamed. In addition, the potential for gaming makes it all the more important that financial rewards and penalties are set conservatively in the beginning, and only increased once regulators and utilities gain experience with the performance incentive mechanism.

Manipulation can be more difficult to detect, particularly when data are collected and analyzed by the utility. To reduce the risk of manipulation, verification methods should be adopted and independent third parties used to collect, analyze, and verify data where practical. Complex data analysis techniques that are difficult to audit should generally be avoided, as they reduce transparency.

6.4. Summary of Key Performance Incentive Mechanism Design Principles

The table below provides a recap of the key principles for performance incentive mechanism design.

Table 16. Key Principles and Recommendations

Regulatory Contexts **(Chapter 2)**	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics **(Chapter 3)**	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets **(Chapter 4)**	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties **(Chapter 5)**	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

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APPENDIX A – DETAILED CASE STUDIES

California

California has a long history of employing various performance incentive mechanisms, and much can be learned from the successes and failures of these experiments. Here we discuss a few of the performance incentive mechanisms that have been employed in California, focusing particularly on the lessons that have been learned along the way.

It is often easier to point out instances of when mechanisms have gone awry than where mechanisms have functioned well, due to the amount of attention garnered by the former. For this reason, much of the discussion below highlights the challenges that have been encountered along the way and strategies for avoiding similar difficulties in the future. This should not be taken to imply that performance incentive mechanisms always or often encounter these problems. Indeed, California's willingness to continue to experiment with performance incentive mechanisms indicates that regulators continue to believe that they are a useful regulatory tool.

Nuclear Power Plant Performance

Diablo Canyon Nuclear Incentives

The 1980s were characterized by numerous nuclear power plant cost overruns and generally low industry-wide nuclear plant capacity factors. Pacific Gas and Electric's (PG&E's) $5.5 billion Diablo Canyon power plant was one example of a power plant that exceeded its estimated construction budget by several billion dollars.

In 1988, the California Public Utilities Commission (CPUC) authorized a settlement regarding Diablo Canyon that was intended to protect ratepayers from the significant cost overruns of the plant, while encouraging the plant to operate efficiently. Instead of allowing PG&E to recover all of the costs of the plant automatically, the settlement based a large portion of the cost recovery on the amount of electricity that would be generated by Diablo Canyon. Energy from the plant was to be paid a set price per kilowatt-hour, and the utility would only recover all of its costs if the plant operated at a high capacity factor. Further, the utility and its shareholders assumed responsibility for all repairs and additional investments at Diablo Canyon (CPUC 1988).

The settlement shielded ratepayers from the risk that the plant would perform poorly or incur significant additional costs. However, there were three aspects of the performance incentive mechanism in the settlement that would ultimately work to the disadvantage of ratepayers:

- First, the target capacity factor above which PG&E would earn a profit was set based on industry averages, rather than based on the much higher-than-average capacity factor of Diablo Canyon at the time of the settlement.[25]

- Second, the financial reward to PG&E for generating electricity from the plant was set at a fixed price (escalated for inflation), rather than being flexible to account for changing market conditions. As a result, ratepayers continued to pay a set price per kWh of electricity from Diablo Canyon even when it would have been more economical to use energy from other sources (such as oil or gas) (CPUC 1988). Although the price set for electricity from Diablo Canyon appeared reasonable at the time, in later years Diablo Canyon power became significantly more expensive than power sold on the West Coast wholesale market.[26]

- The performance incentive mechanism contained no shared savings component or other safety valve that would have reduced the consequences of getting either of the above two elements wrong.

PG&E successfully operated the Diablo Canyon power plant, achieving capacity factors much higher than the industry average at the time of the settlement agreement, and producing profits for shareholders. In this way, the incentive mechanism can be said to have been successful in providing an incentive for the utility to operate the nuclear power plant efficiently, but the choice of a target capacity factor and locking in the power plant's energy price did not generate the intended benefits for ratepayers. The performance incentive mechanism ultimately proved to be unstable and was modified in later years and finally eliminated in 2002 through Decision 02-04-016.

A more tenable performance incentive mechanism might have also have (a) included a shared savings component, whereby ratepayers would receive a portion of any profits generated, or (b) tied the price paid for Diablo Canyon power to the avoided cost of power from fossil generators. These components would have distributed the risk more equitably between ratepayers and the utility.

<u>Palo Verde Nuclear Incentives</u>

In the 1990s, California adopted additional performance incentive mechanisms for other nuclear power plants, including the Palo Verde Nuclear Generating Station. The terms of this incentive mechanism were modified from those of Diablo Canyon: the utility would receive a reward for generation above a capacity factor of 80 percent, and the reward would be calculated based on the difference between Palo Verde's incremental variable cost and the cost of replacement power. In addition, the performance incentive mechanism initially included a provision for sharing of benefits between shareholders and ratepayers in later years, although this provision was eliminated before it took effect (CPUC 2001).

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[25] The capacity factor from the date of commercial operation through June 30, 1988 was 67.7% for Unit 1 and 76.7% for Unit 2, as compared to an industry average of 58% for similar large nuclear power plants (CPUC 1988, 112, 114).

[26] In 1994, Diablo Canyon was earning more than 12 cents/kWh, while Western Market wholesale power prices were approximately 3 cents/kWh (Smeloff and Asmus 1997, 82).

Although this performance incentive mechanism incorporated greater protections for ratepayers than the PIM for Diablo Canyon, it ultimately also proved to be unstable. When the PIM was initially developed, the cost of replacement power was expected to be in the range of $0.03 to $0.05 per kilowatt-hour, but by summer 2000, these costs had escalated to more than ten times higher. For this reason, stakeholders lobbied for a limit on the incentive payments and the commission instituted a cap of $0.05 per kilowatt-hour (CPUC 2001).

The Palo Verde incentive mechanism was initially designed to expire at the end of 2001, at which point Palo Verde would be returned to cost-of-service ratemaking. Upon petition by SCE, the incentive mechanism was continued until SCE's next general rate case, effective May 22, 2003 (Southern California Edison 2006a).

Lessons Learned

California's experience with nuclear power incentives highlight just how difficult it can be to set a reasonable target and incentive payment. These difficulties can be mitigated by using shared savings mechanisms or instituting safety valves—such as Palo Verde's cap on the incentive payment.

Gaming and Manipulation of Performance Incentive Mechanisms

In 1990, the CPUC began an investigation into incentive-based ratemaking for gas utilities (R90-02-008 and I90-08-006), finding that a PBR plan with indexing could "provide substantial benefits in increased efficiency, innovation, ratepayer protection, risk allocation, and regulatory simplicity" (CPUC 1991, 1). Beginning in 1993, the CPUC approved gas procurement mechanisms for the gas utilities that replaced after-the-fact reviews of gas procurement with market-based gas price benchmarks.

Soon, the CPUC began to also approve PBR mechanisms for electric utilities. PBR was introduced as an alternative to cost-of-service regulation, which the Commission felt had become "too complex to allow us to regulate utilities effectively" (CPUC 2008, 2). The Commission hoped that PBR plans would help them find "new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations" (CPUC 2008, 3).

A PBR plan was adopted for Southern California Edison (SCE) though Decision (D.) 95-12-063 and modified by D.96-09-092. Three categories of service incentives were created: reliability, customer satisfaction, and health and safety.

SCE's Customer Satisfaction Incentive Mechanism terminated at the end of 2003, while some form of Employee Health & Safety Incentive Mechanism continued through 2005 (Southern California Edison 2006b). From 1997 to 2000, SCE received $48 million in rewards under the customer satisfaction and health and safety incentive mechanisms. Subsequently, SCE requested $20 million in customer satisfaction rewards for 2001 to 2003 and $15 million in health and safety rewards for 2001 and 2002. However, in a 2008 decision, the CPUC ordered SCE to refund these rewards and forgo the additional rewards requested, as well as pay a fine totaling $30 million. The problems leading to this decision are briefly described below, followed by remarks regarding how such results might be avoided in the future.

Customer Survey Problems

Under the Customer Satisfaction Incentive Mechanism, customer satisfaction was measured through the use of third-party administered surveys with rewards and penalties in four areas: field services, local business offices, telephone centers, and service planning. Each area received a score of 1 to 5+, where 1 was low. Scores were then averaged across the four service areas to obtain the overall average score (CPUC 2008).

The original target for the overall customer satisfaction score was set to 64% of scores being 5 or 5+, with a deadband of plus or minus 3%. Beyond the deadband, the utility received a reward or penalty of $2 million for each percentage point change in the average result, up to a maximum of $10 million per year. In addition, if any one area received a score of less than 56%, a penalty would be assessed. In D.02-04-055, the Commission increased the customer satisfaction target from 64% to 69%, based on the average of the then most recent nine years of survey results (CPUC 2008).

The problems with the customer survey began with the selection of customers for the survey pool. This exercise was left to the meter readers themselves, who were supposed to push a button on a handheld device they carried every time they had a meaningful interaction with a customer (whether it was positive, neutral, or negative). However, there was no practical means of ensuring that meter readers actually did record interactions that were both positive and negative. In addition, SCE employees sometimes falsified the contact information to screen out customer interactions that might result in negative customer satisfaction surveys (CPUC 2008).

Further, some SCE employees attempted to skew survey results favorably by requesting that customers give them a good score when surveyed, giving customers collateral materials (such as golf balls and ball point pens), or telling customers that a survey score of less than 5 would represent a failing score that might lead to disciplinary action against the utility employee (CPUC 2008).

Thus despite using a third party to administer the customer satisfaction survey, the performance incentive mechanism failed because the data collection process was exposed to data manipulation and gaming by utility employees. The issue only came to light when a whistle blower wrote an anonymous letter to an SCE senior vice president. Even then, the initial review of the allegations concluded that any survey problems were inadvertent. After another anonymous letter was received with more serious allegations (including that SCE managers and high-level directors were aware of the conduct), an independent investigation was launched that began uncovering the misconduct. Ultimately, the California Public Utilities Commission found that from 1997 through 2003, SCE “manipulated and skewed survey results, artificially inflated survey outcomes, and received PBR rewards” (CPUC 2008, 16).

Underreporting Employee Health and Safety Incidents

Employee health and safety was measured by the number of first aid incidents and lost time incidents, based on historical averages as reported to OSHA. Based on that data, the benchmark was set at 13.0 injuries and illnesses per 200,000 hours worked with a dead band of +/-0.3. In 2002, the target was reduced to 9.8 injuries and illnesses based on the most recent seven years of data, and in 2003 it was further reduced to 8.6 injuries and illnesses. Results above or below the dead band would result in rewards or penalties (CPUC 2008). Unfortunately, from the beginning this performance incentive mechanism was deeply flawed.

As with the customer surveys, the first problem with the Employee Health and Safety Incentive Mechanism was that data were not appropriately collected – both in the establishment of the performance target and for compliance reporting. To begin with, the utility did not establish a system to track all first aid incidents, leading to underreporting of the data used to establish the performance target, as well as the compliance data. Further, SCE maintained different standards for internal safety performance measures than for compliance with the performance incentive mechanism. The unsurprising result was that only a small fraction of first aid incidents were reported.

Second, the existence of the incentive mechanism actually discouraged employees from reporting injuries. The Commission found that particularly "when safety incentives are group-based (as they are in some business units), injured employees may want to avoid reporting their injuries and jeopardizing safety incentive compensation not just for themselves, but also for the rest of their group" (CPUC 2008, 60)

In addition, some supervisors participated in or encouraged under-reporting of data. "Among the methods used to disguise injuries and avoid internal reporting are: employee self-treatment; treatment by personal physicians rather than the company doctor; timecard coding of lost time as sick days or vacation; etc." (CPUC 2008, 60).

Lessons Learned

In both the customer satisfaction and health and safety incentive mechanisms, data collection was seriously flawed. These experiences highlight the need to validate data frequently and to employ independent third parties for data collection where possible. However, the disincentive for employees to self-report health and safety data may be too great to overcome. Because of the great importance of maintaining a safe work environment, some jurisdictions have elected to eliminate performance incentives for health and safety in order to avoid creating perverse incentives. This does not mean that such data cannot or should not be tracked, but financial rewards or penalties should be carefully considered.

Recent Experience with Performance Incentives in California

In the early 2000s, California abandoned performance-based ratemaking and returned to "a transparent regime of cost-based ratemaking" (CPUC 2004, 288). However, the Commission elected to continue to use performance incentive mechanisms, as

> "they provide a more responsive approach to deviations in service adequacy and quality than our other ratemaking mechanisms.… They can be carefully adapted to the cost-of-service regime and enhance our ability to regulate in the public interest, providing both financial incentives to guide utility activities and an early warning of longer-term trends

> that we can use to guide more intrusive regulatory interventions such as complaints and investigations. They represent a calibration, not a contradiction, of our cost-of-service principles" (CPUC 2004, 289).

Although the customer service and health and safety performance incentive mechanisms as described above have been discontinued, the California Public Utilities Commission has continued to experiment with performance incentive mechanisms where warranted. Under a cost-of-service regime, however, the CPUC requires that the need for such incentives be fully justified, stating:

> "We will consider whether the proposed performance incentives are necessary for achieving one or more of our regulatory objectives and are likely to be cost-effective; we do not believe that performance incentives should be adopted solely on the basis of their mere consistency with a particular objective. Since rates set through our conventional approach to ratemaking are intended to provide the funding required to meet the regulatory objectives of safe and reliable service, we must ask why the utility needs the possibility of additional ratepayer funding, or threat of reduced funding, to get the utility to do what it is already funded and expected to do. The burden is on the proponents of performance incentives to prove they are necessary, cost-effective, and otherwise reasonable" (CPUC 2004, 290).

Renewable Energy Procurement Costs

California has long had a Renewable Portfolio Standard (RPS), but certain provisions in the enforcement rules caused CPUC become concerned that construction delays and contract failures could jeopardize PG&E's compliance with the RPS (CPUC 2010). The RPS enforcement rules contained loopholes to deal with the cumbersome, short annual compliance period that was required by legislation, such as allowing retail sellers to incur a certain percentage of their annual procurement obligation as a deficit without explanation. As another example, the rules allowed "earmarking" of future contracted deliveries for the current compliance period, even if deliveries were not anticipated to commence in the current compliance period (CPUC 2014a).

In February 2009, PG&E filed a proposal—with no performance incentive component—to implement and recover costs of a photovoltaic (PV) program. In response to recommendations by other parties, the CPUC approved the program but adopted a price cap of $246 per MWh and a cost savings incentive mechanism "to better align PG&E's financial interests with those of ratepayers" (CPUC 2010, 31).

The program target called for installing 50 MW of utility-owned PV capacity per year for five years (for a total of 250 MW of utility owned generation). PG&E could also enter into power purchase agreements (PPAs) for up to 250 MW of PV. Under the cost savings incentive mechanism, PG&E shareholders were permitted to retain 10% of cost savings if actual average capital costs over the life of the PV Program fell below $3,920 per kW, representing PG&E's capital cost estimate with no contingency amount. Ratepayers were entitled to retain 90% of the cost savings below $3,920 per kW. Although the CPUC did not specify a penalty, capital costs above $4,312 per kW were subject to a reasonableness review.

Notably, PG&E opposed the cost cap and cost savings incentive mechanism, largely on the grounds that these elements exposed PG&E to uneven risks and rewards (CPUC 2010, 55–56).

In December 2012, PG&E requested to terminate its PV Program after the second PV PPA solicitation and to procure the remaining capacity using the Renewable Auction Mechanism (RAM) process adopted by the CPUC in D.10-12-048 instead. The CPUC rejected the request on procedural grounds. In February 2014, PG&E resubmitted its request, claiming that terminating the PV Program and using the RAM process to procure the remaining capacity would create significant administrative efficiencies, would reduce customer costs, and was appropriate given that the PV sector had significantly transformed since the PV Program was approved in 2010 (PG&E 2014). In November 2014, the CPUC granted PG&E's request to close the PV Program, noting that the CPUC's goals in establishing the program were substantially achieved and the availability of other procurement tools for smaller scale RPS-eligible products, making the PV program duplicative and administratively burdensome (CPUC 2014b, 14).

Lessons Learned

The experience with the PV Program cost savings incentive mechanism suggests that asymmetrical risk and reward mechanisms are likely to garner opposition by utilities. In this case, PG&E shareholders were permitted to retain only 10% of the cost savings below its capital cost estimate excluding contingency, and costs above the cost cap would be subject to regulatory review. On the other hand, ratepayers were entitled to retain 90% of the cost savings below $3920 per kW, and they were protected from the downside by a cost cap provision.

Another lesson from this experience involves consideration of administrative burden and redundancy. The potential rewards for the company were apparently not enough to outweigh the administrative burden of maintaining the PV Program. Given that the RAM process had matured since the inception of the PV Program, the latter became redundant.

The UK RIIO Model

When the British energy distribution and transmission utilities were privatized in 1990, a performance-based regulatory framework was adopted with a price control mechanism to regulate the utilities. This form of PBR was referred to as "RPI-X," as it allowed revenues to grow at the rate of the retail price index (RPI), less an X-factor which was designed to capture improvements in productivity, rewards and penalties, or other elements. The term of each PBR period was set at five years in order to incentivize efficiency improvements and cost reductions (the savings from which the utilities would retain until the end of the price control period). In order to prevent service quality degradation, the RPI-X plans also specified certain outputs that the utilities were required to deliver.

Over the past twenty-five years, this performance regulation framework has evolved to adapt to changing policy priorities and industry challenges. In 2008, the British Office of Gas and Electricity Markets ("Ofgem"), launched a fundamental review of the regulatory framework. Out of this review and stakeholder discussion was borne a revised form of PBR, one more comprehensive and performance-based than the RPI-X system. This new framework is referred to as "RIIO," an abbreviation for Revenue = Incentives + Innovation + Outputs.

RIIO seeks to improve upon the RPI-X model and respond to concerns that:

- The RPI-X framework focused the utilities on achieving cost savings, but not on delivering other outputs, such as improved quality of service.
- The five-year duration of the RPI-X price control period was not sufficient to encourage companies to focus on long-term trade-offs and effects of investments, innovation, and service quality.
- The RPI-X framework was not flexible enough to respond and adapt to step-changes in technology. Additional incentives were felt to be needed to stimulate innovation and adequately respond to sector-wide need to transition to a low-carbon energy industry (Jenkins 2011).

RIIO was designed to address these concerns by (a) shifting the focus from cost control to delivery of outputs through the use of performance incentives, (b) increasing the price control period to eight years, (c) increasing the focus on innovation through financial incentives and an innovative projects competition, and (d) increasing the emphasis on competition where possible. It is expected that these adjustments will encourage utilities to innovate to deliver cost savings and value for customers, as the utilities will retain most of the efficiency savings they generate for a longer period and they have the potential to earn rewards for over-delivering in certain performance areas.

Base revenues under RIIO are determined through utility business plans. These plans must be well-justified and designed to establish a long-term corporate strategy for delivering "value for money" to customers. In developing their business plans, the utilities are required to assess alternative options for delivering outputs, evaluate the long-term costs and benefits for each alternative, and incorporate stakeholder input. Once approved, the business plans form the basis for revenue adjustments over the next eight years, with annual true-ups to account for differences in actual versus projected sales. A sharing mechanism allows utilities and customers to share any savings or overages relative to the budget, with the majority of shared savings generally accruing to the utility (ENA 2014; Ofgem 2013a).[27]

In addition to the base revenues established through utility business plans, utilities may be rewarded or penalized based on their performance in delivering specific outputs. As discussed in detail in the following sections, these rewards and penalties can have a relatively large impact on each utility's realized return on equity, with impacts of up to approximately +/- 300 basis points (Ofgem 2014b).[28]

The electric distribution network price control period will begin on April 1, 2015 and last until March 31, 2023. At the time of writing, the electric utilities had submitted their business plans to Ofgem for review, and Ofgem had approved (with modification) all of the plans. One utility's plan was "fast tracked" and accepted in full, due to it being of sufficiently high standard. The fast-tracked utility also received a reward equal to 2.5 percent of "totex" (capital expenditures + operating expenditures). The other five utilities' plans were approved, but with allowed revenues of approximately 5 percent less than requested in their business plans (Ofgem 2014b).

RIIO Outputs

Outputs are a core element of the RIIO regulatory framework, falling in six categories:

1. Safe network services
2. Environmental impact
3. Customer satisfaction
4. Social obligations
5. Connections
6. Reliability and availability

Within each of these categories, "secondary deliverables" have been identified upon which utilities will be required to deliver. For example, one of the secondary deliverables under the environmental impact category is a utility's total CO_2 equivalent emissions.

A series of working groups was established in order to identify specific metrics and incentives for each of these deliverables. Ofgem also received input from the Consumer Challenge Group, a small group of

[27] The percent of savings that the utility can retain under the "efficiency incentive" ranges from 45 percent to 70 percent, depending on whether the utility is fast-tracked or not, and the degree to which the utility's forecasts align with Ofgem's models. This sharing rate is set as part of the Informational Quality Incentive (Ofgem 2013a).

[28] The financial impacts of the performance incentive mechanisms associated with specific outputs are in addition to total expenditure efficiency incentives, informational quality incentives, and rewards associated with compiling a high-quality business plan. These other incentives could have an additional impact of more than 100 basis points in either direction. See Figure 10 for the total impact of these factors.

consumer experts that work to ensure consumers' interests are fully considered. Targets for many metrics are set by the Ofgem with input from stakeholders, while for some metrics (such as asset health), utilities propose the targets themselves in their business plans. All targets proposed by utilities must be justified in terms of costs and benefits to customers and informed by stakeholder engagement (Ofgem 2012a).

Not all outputs under RIIO have financial incentives. For example, the Reliability and Safety Working Group rejected the use of incentives (financial or reputational) for safety, as it was felt they could result in unwanted implications for incident reporting (as occurred in California, described in the previous section). Moreover, utilities are already required to comply with health and safety standards set by another governmental agency, and would be subject to enforcement action from that agency in the event of non-compliance (Ofgem 2012a).

Some categories of outputs have "reputational" incentives, where results are published and utility performance compared against other utilities, but no financial incentives are imposed. For example, under the Business Carbon Footprint metric, each utility submits an annual report of its total CO_2 equivalent emissions, as well as the actions it has taken to reduce emissions relative to their baseline. This allows utilities to share best practices and learn from one another, while also providing time to refine data collection and analysis techniques to provide more reliable data prior to administering rewards and penalties (Ofgem 2012a).

In addition, Ofgem is careful to ensure that in areas where competition exists (such as connection services) no incentive benefits are provided to utilities that are not also available to independent providers. The total package of incentives are intended to be clear and balanced in order to prevent perverse incentives, and to ensure that utilities that provide value for customers' money earn a relatively high rate of return, while utilities that fail to deliver value earn low returns (Ofgem 2012a).

The following subsections summarize the performance incentive mechanisms currently in use or under development for RIIO. Utilities must also report on several performance metrics (such as noise, sulfur emissions) that do not have corresponding financial or other incentives and are therefore not listed in the table below. For more information, see Ofgem 2013a and Ofgem 2013b.

Environmental Impact

Currently two performance incentive mechanisms are associated with the environment impact category: electricity losses and business carbon footprint. UK utilities are contractually obligated to reduce losses as much as practicable, and can be found in violation of their license agreement if they fail to do so. If utilities are particularly successful or innovative in reducing losses, they may qualify for a reward, which increases over the duration of the PBR period in order to incentivize implementation of long-term solutions.

The incentive under the business carbon footprint is unusual in that it is reputational only, due to Ofgem's determination that data are not sufficiently reliable to form the basis for financial rewards or penalties (Ofgem 2012a).[29] Under this mechanism, utilities' performance is reported annually and made public by Ofgem. All utilities' results are aggregated into one table to facilitate comparisons across utilities.

Table 17. RIIO Environmental Impact Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Electricity losses	Discretionary reward of up to £4 million in year 2, £10 million in year 4, and £14 million in year 6 for utilities that exceed the loss reduction commitments in their business plans.	Utilities report annually on loss reduction activities undertaken, improvements achieved, and actions planned for the following year. Performance will be measured according to multiple criteria, including the effectiveness of actions taken to reduce losses, engagement with stakeholders, innovative approaches to loss reductions, and sharing of best practices with other companies.
Business Carbon Footprint (BCF)	Reputational	Annual reporting requirement on CO_2 equivalent emissions, actions taken to reduce emissions over the past year and their effectiveness. All utilities' performance on this metric summarized in one table.

Source: Ofgem 2012 and Ofgem 2013

[29] A distribution utility's business carbon footprint is in part based on contractor emissions, which may not be sufficiently reliable.

Customer Satisfaction and Social Obligations

Three performance incentive mechanisms are in place to measure customer satisfaction and the degree to which utilities fulfill social obligations such as assistance to vulnerable customers. Two of these performance incentive mechanisms, complaints and stakeholder engagement, are asymmetrical. Complaints are associated with a penalty only, while stakeholder engagement can only result in a reward.

Table 18. RIIO Customer Satisfaction and Social Obligations Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Customer satisfaction survey	Reward or penalty up to 1% of annual base revenue	A survey is used to measure the satisfaction of customers who have required a new connection, have experienced an interruption to their supply, or have made a request for a service or job to be completed. Performance is measured based on the response to the question: “Overall how satisfied were you with the service that you received?” The target score will be set at the beginning of the period, and will be set at a level that "can be objectively assessed to represent a good level of performance."
Complaints	Penalty of up to 0.5% of annual base revenue. No reward.	Complaints and their weightings are measured based on: (a) percentage of complaints that are outstanding after one day (10% weighting); (b) percentage of complaints that are outstanding after 31 days (30% weighting); (c) percentage of complaints that are repeat complaints (50% weighting); and number of Energy Ombudsman decisions that go against the utility as a percentage of total complaints (10% weighting). An industry target is set.
Stakeholder engagement	Reward of up to 0.5% of annual base revenue. No penalty.	The regulator will develop a mechanism for assessing the utilities' use of data and customer insight to understand and identify effective solutions for vulnerable consumers, as well as their ability to integrate this into core business activities.

Source: Ofgem 2012 and Ofgem 2013

Connections

In addition to the customer satisfaction survey (which measures, in part, satisfaction with the utility's service in interconnecting new customers or distributed generation facilities), two performance incentives encourage the utilities to efficiently interconnect residential customers and respond to the needs of large customers (including distributed generation). These incentives are asymmetrical; a reward (but no penalty) can be earned for the time required to process small customer interconnections, while the incentive for large connections (including distributed generation) is penalty-only.

Table 19. RIIO Connections Performance Incentive Mechanisms

Deliverable	Penalty or Reward	Metric and Target Description
Time to Connect Incentive for Small Connections	Reward of up to 0.4% of annual base revenue. No penalty.	Measures the time taken from initial application received to the issue of a quotation and the time taken from quotation acceptance to connection completion. Target based on historical performance data, and target will become more stringent over the period.
Incentive on Connection Engagement (ICE) for Large Connections	Penalty of up to 0.9% of annual base revenue. No reward.	Each utility must submit evidence of how they have identified, engaged with, and responded to the needs of their customers. These submissions will be compared to a set of minimum requirements, which will likely to require each utility to demonstrate how they have engaged with a broad range of customers, established relevant performance indicators, and developed a forward-looking work plan of actions to improve performance (with associated delivery dates). Separate submissions will be required for different market segments, including distributed generation customers. A penalty will be assessed for failing to meet the minimum requirements for that market segment. The regulator will also continue to engage with stakeholders to identify key issues and gather feedback on utility performance.

Source: Ofgem 2012 and Ofgem 2013

Reliability and Availability

Several performance incentive mechanisms are in place to ensure reliability and availability. These performance incentives carry sizeable rewards and penalties, based largely on studies of customers' willingness to pay. The interruptions incentive scheme is most comparable to SAIDI and SAIFI rewards and penalties in the United States, but has separate components for unplanned versus planned outages. Because the utilities provide prior notice to customers regarding planned outages, they are less disruptive to customers. For this reason, planned outages carry a lesser financial reward or penalty as compared with unplanned outages (Ofgem 2012b; Ofgem 2013b).

The guaranteed standards of performance incentives reflect a 2010 law (SI No. 698, 2010.27) that requires utilities to make payments to customers whenever performance falls below a certain level. For example, the 2010 law requires a payment from the utility directly to affected customers who experience outages lasting more than 18 hours, or who experience four or more outages a year. RIIO maintains or strengthens these existing standards.

Finally, RIIO also penalizes or rewards utilities that under- or over-deliver on the health and load indices of their assets. Utilities target a certain level of output delivery in their business plans, which then form the basis for their allowed revenues in this area. (These performance levels must be justified through both cost-benefit analysis and stakeholder engagement.) Under-performance therefore results in both a penalty and a downward adjustment to future allowed revenues, while over-performance results in a reward and higher future allowed revenues (Ofgem 2012b; Ofgem 2013b).

Table 20. RIIO Reliability and Availability Performance Incentive Mechanisms

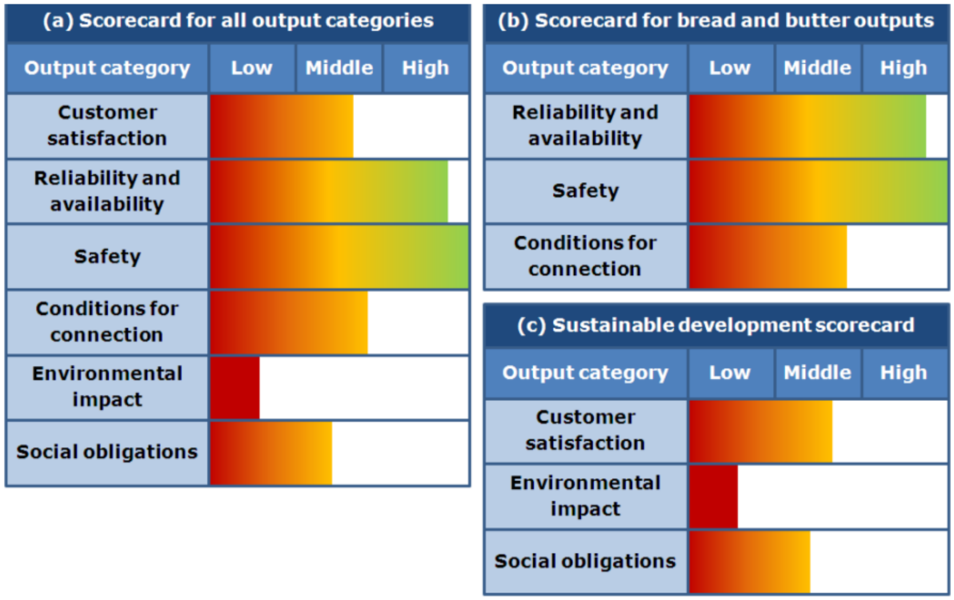
Deliverable	Penalty or Reward	Metric and Target Description
Interruptions Incentive Scheme	Penalty or reward of up to 250 basis points on rate of return per annum	Utilities are incentivized on the number and duration of network supply interruptions versus a target derived from benchmark industry performance. Planned and unplanned outages have separate targets, and planned outages are rewarded and penalized 50% less than unplanned outages. Annual utility targets for planned interruptions are set using a three-year rolling average, with a two-year lag. (That is, the 2015-16 target would be the average over the 2011-12 to 2013-14 period.) Unplanned outage targets are set using a combination of utility and industry average for Low Voltage (LV), Extra High Voltage (EHV), and 132kV. Exceptional events are excluded from the performance data. Utilities can propose alternative targets in their well-justified business plans.
Guaranteed Standards of Performance	Penalty: Direct payments to each customer affected, typically of approximately £30/customer	Customers are eligible for direct payment of specific fixed amounts where a utility fails to deliver specified minimum levels of performance. For example, if the duration or frequency of interruptions exceed a pre-specified level, the utility must make a payment to a customer. Vulnerable customers on the Priority Service Register will receive automatic payments, while other customers will need to apply to their utility for payment.
Health and Load Indices	Penalty for under-delivery equal to reduced future allowed revenues and 2.5% of the value of the under delivery, or a reward for over-delivery equal to 2.5% of the incremental costs associated with over delivery and an upward adjustment to future allowed revenue.	Risk reduction associated with the condition and loading of assets. These metrics encourage longer-term strategies by linking the longer-term reliability benefits of healthier and less highly-loaded assets to a measurable deliverable within the price control.

Source: Ofgem 2012b, Ofgem 2013b

Scorecard for Outputs

To facilitate comparison across companies, Ofgem intends to develop scorecards for each of the companies' performance across the categories of output. Although the details have not yet been fleshed out, the scorecard will measure performance relative to a normalized baseline, as presented in the illustrative example below.

Figure 9. Illustrative Scorecard for Outputs



Source: (Ofgem 2010)

Lessons Learned

Under RIIO, a suite of performance incentive mechanisms, together with a comprehensive revenue cap mechanism, has been designed to encourage utilities to meet the needs of their customers in a cost-effective manner. Even though this new PBR framework is still being developed and has yet to be applied, several lessons can be drawn from the UK experience.

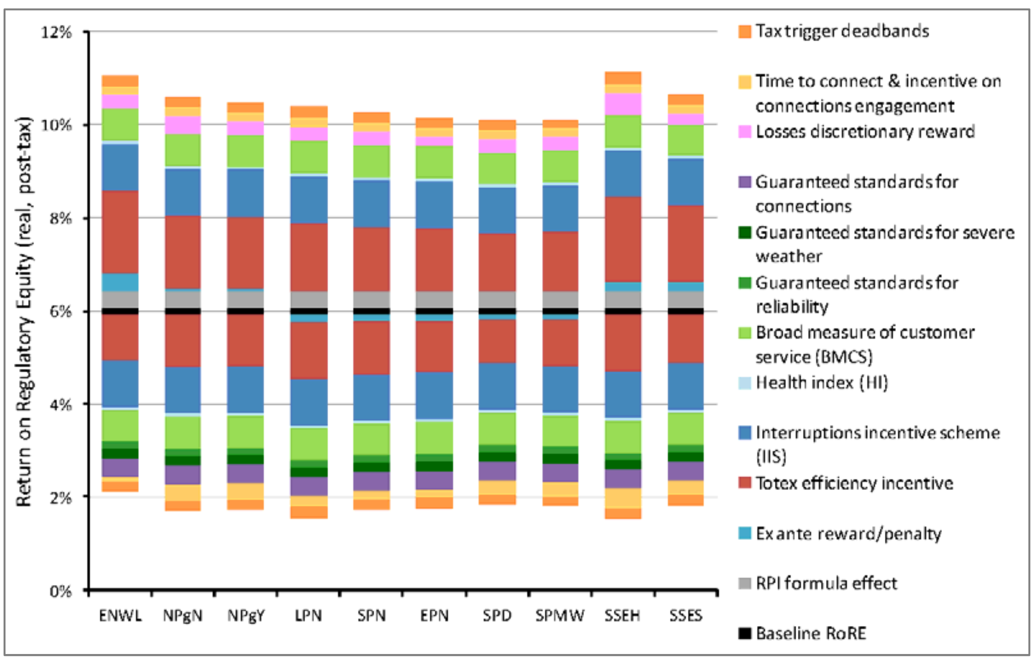
The evolution of the UK PBR framework provides an indication of the limitations to the simpler version of performance-based regulation that has been in place in the US, and the UK experience mirrors some of the challenges with PBR that US regulators have wrestled with in recent years. Many of the new RIIO elements described above (e.g., expanding the price control period, more focus on outputs, more attention to future planning in the business plans, increased use of capital cost trackers), reflect the aspects of simple PBR that have been insufficient in achieving PBR's ultimate goals. Regulators in the US who are looking to PBR as a new utility regulatory model should take note of the implications of these new RIIO elements.

One of the key lessons from the evolution of PBR in the UK relates to regulatory engagement. When PBR was introduced in the UK, and shortly after in the US, it was referred to as "hands-off" regulation. For example, the California PUC wrote that it hoped that PBR plans would help them find "new ways to reduce regulatory interference with management decisions and to allow utilities more flexibility in their day-to-day operations" (CPUC 2008, 3). However, the experience from the UK is just the opposite. It is clear that the new RIIO mechanism will requires significant utility and regulatory resources up front due to the extensive nature of the business plan development and review process, as well as the up-front effort necessary to create balanced and effective performance incentive mechanisms. Note that over the last five years, the number of Ofgem employees have doubled to more than 700 full-time employees.[30] Even after the development and approval of the utility business plan, Ofgem will probably need to dedicate considerable resources to the oversight and implementation of the performance incentives and the other components of the RIIO mechanism.

Relative to performance incentive mechanisms in the United States, RIIO places a large amount of revenues at stake. Potential rewards and penalties for outputs under the environmental, customer satisfaction, social obligations, and connections categories equate to approximately 3 percent of utility annual base revenues. Reliability-related rewards and penalties carry with them the possibility of an additional 250 basis points in rewards or penalties. The results of Ofgem's modeling suggest that utilities' realized return on equity may fluctuate by approximately +/- 300 basis points due to these performance incentive mechanisms (Ofgem 2014b).

These performance incentive mechanisms are integrated into a revenue cap plan that increases revenues each year at the rate of inflation and provides utilities with the ability to retain a significant portion of any cost efficiency savings. Allowed revenues are set using a 6 percent return on equity, but actual earnings may vary significantly based on utility performance. According to Ofgem's modeling, the actual ROEs for "slow-track" utilities are likely to range from approximately 2 percent to more than 10 percent, as shown in the figure below (Ofgem 2014b).

Figure 10. Plausible ROE Ranges for UK Distribution Utilities



Source: Ofgem 2014b, page 46

[30] The number of permanently-employed staff at Ofgem has grown from 310 employees in 2008/2009 to 761 in 2013/2014 (Ofgem 2009; Ofgem 2014a).

This wide variability of potential utility returns is by design, as Ofgem determined early on that high-performing utilities should have the opportunity to earn an ROE of greater than 10 percent, while poorly performing utilities could earn an ROE of less than the cost of debt. Ofgem notes that the results shown in the figure above indicate that the package of risk and incentives has been “appropriately calibrated” (Ofgem 2014b, 46). The relatively large magnitude of incentives under RIIO not only helps to focus management attention on the attainment of the established targets, but may also help to provide the revenues necessary for innovating and implementing new technologies.

The RIIO process for developing performance incentive mechanisms relied upon significant amounts of stakeholder feedback, ranging from utilities to consumer groups. However, not all of the performance incentive mechanisms appear to have been fully developed yet, particularly for stakeholder and customer engagement. This is perhaps not surprising, as metrics based upon more qualitative data are difficult to define and can be difficult to administer. Lessons learned from the UK’s experience with these more qualitative performance incentive mechanisms will be instructive for the development of similar valuable, but difficult-to-quantify performance targets elsewhere.

RIIO’s performance targets are generally linked directly to utility business plans or industry-wide performance levels, which helps to ensure that the targets are reasonable and that the utilities will have the funds required to make investments to meet these targets. In some cases, such as interruptions and availability, rewards and penalties are based on customer willingness-to-pay surveys in order to balance the value of improved reliability with the associated costs.

Lastly, RIIO’s use of “reputational” incentives for reducing carbon emissions provides an example of how simply displaying a comparison of utility performance in an easily and publicly accessible manner can encourage utilities to take steps to improve their performance, particularly for areas that are important for customers, such as carbon emissions. While the reputational incentive may not always be sufficient for achieving the level of performance desired, it represents a relatively simple and risk-free first step. Moreover, it allows data collection processes and definitions to be standardized and clarified prior to applying high-stakes financial incentives.

New York

During the 1990s, New York experimented with numerous performance incentive mechanisms for its electric and gas utilities. For example, the 1991 Measured Equity Return Incentive Program (MERIT) for Niagara Mohawk Power Company was designed to address a variety of aspects of the company's operations, including nuclear plant performance, the amount of payments to outside law firms, and environmental performance. The program resulted in significant improvements at Niagara Mohawk, and various performance incentive mechanisms were subsequently adopted at other New York utilities, generally under a comprehensive PBR plan with a price cap (Biewald et al. 1997).

The breadth of performance incentive mechanisms in use in New York was substantially reduced following restructuring as generation assets were spun off and subjected to the discipline of the market. Recently, however, New York has developed a renewed interest in performance incentive mechanisms as a means of reshaping utility incentives. In April 2014, the New York Public Service Commission (PSC) initiated the Reforming the Energy Vision docket with the goal of better aligning utility interests with state energy policy objectives. Although the docket is currently on-going, the initial straw proposal envisions moving toward a more "outcome-based approach to ratemaking" with metrics based on state energy policy goals (NY DPS Staff 2014).

A key component of the Reforming the Energy Vision (REV) proceeding is the desire to place distributed energy resources on a level playing field with traditional investments. While the REV proceeding is expected to develop a new ratemaking framework to achieve this goal, New York is already taking steps toward a new regulatory paradigm. In December 2014, the PSC approved incentives to reward the use of cost-effective distributed energy resources through a project called the Brooklyn Queens Demand Management (BQDM) program.

The Brooklyn Queens Demand Management program was proposed by Consolidated Edison Company (ConEd) to address load growth in the Brooklyn and Queens areas of New York. Rather than constructing a new area substation, a new switching station, and new subtransmission feeders (at a cost of approximately $1 billion), ConEd proposed to implement a portfolio comprised of distributed energy resources and other low-cost traditional utility-side solutions to address the forecasted summer overloads at a much lower cost (NY PSC 2014).

The PSC found that the BQDM project and associated incentives represented a valuable opportunity to explore changes to traditional utility operations and ratemaking, stating "this Commission must itself innovate in order to support innovation by utilities and third parties" (NY PSC 2014, 15). In order to ensure that the utility is indifferent to investments in distributed energy resources and traditional infrastructure investments, the Commission approved several financial incentives for ConEd. Specifically, the PSC approved:

- A regulated return on the alternative investments,
- A 10-year amortization period for the investments,

- A 100 basis point ROE adder on BQDM program costs tied to the achievement of specific outcomes related to achieving a certain capacity of alternative measures, increasing diversity of distributed energy resource vendor market, and implementing a portfolio that has a lower cost than the traditional solution. These performance incentives are defined in Appendix B of the order as follows (NY PSC 2014):

  1) Quantity of Alternative Measures:

     a. Metric: Capacity of alternative measures installed

     b. Target: 41 MW

     c. Financial incentive: 45 basis points for meeting or exceeding target

  2) Diversity of DER Vendor Marketplace:

     a. Metric: Normalized entropy index, calculated as follows:

     $$normalized\ entropy\ index = \frac{\sum_{i=1}^{N} S_i \ln(S_i)}{\ln(N)}$$

     Where N is the number of DER Providers and S_i is the share, in MWh, of each provider in the selected portfolios.

     b. Target: Baseline set at 0.75; maximum reward occurs at 1.0

     c. Financial incentive: One basis point earned for each 0.01 increase in the normalized entropy index above the baseline (up to 25 basis points).

  3) Reduction in Dollar/MW Costs:

     a. Metric: Assembling a portfolio of solutions that achieves a lower $/MW lifecycle cost (based on the net present value) than the traditional investment solution (30 basis points). The lifecycle costs will be calculated by January 31, 2017, using the Company's then-applicable Weighted Average Cost of Capital.

     b. Target: Baseline set at $6 million/MW based on the Company's estimated NPV revenue requirement of 915.6 million to achieve a total capability of 152 MW.

     c. Financial Incentive: For every full 1% reduction in the $/MW of the BQDM Program portfolio and associated investments relative to the baseline, the Company may earn 1 basis point (up to 30 basis points.)

Initial Assessment of the BQDM Performance Incentive Mechanisms

The adoption of the above performance incentive mechanisms provides a clear signal to New York's utilities that distributed energy resources should be valued in a manner similar to traditional investments, and that reducing costs for consumers will be rewarded. The three performance incentive mechanisms (quantity of alternative resources installed, diversity of market, and cost) simultaneously address several of the commission's objectives.

In addition, the commission's choice of incentive formulas appears reasonable. The Company will only be rewarded if it installs the amount of alternative resources required (41 MW), but will not be rewarded more for installing more resources than needed, thereby avoiding an incentive to procure excessive amounts of alternative resources. The choice of linear financial rewards for the diversity index and cost provide incentives to achieve the highest levels reasonably possible, while rewarding the Company proportionately for any improvements made.

However, two aspects of the performance incentive mechanism have some room for improvement: (1) the linkage between rate base and the financial incentive, and (2) the definition of the diversity index. The financial reward's direct link to rate base (through virtue of being an ROE adder) implies that increasing rate base will in turn increase the Company's financial reward, which may exacerbate the Averch Johnson effect and lead the utility to make unnecessary rate base investments. This issue is explored in more detail in the FERC Transmission Bonus ROE case study later in this appendix.

The second issue concerns the diversity index definition. On January 12, 2015, ConEd filed a petition requesting clarification and modification to several aspects of the performance incentive mechanism (ConEd 2015):

- First, the Company pointed out that, as currently defined, the diversity index focuses on the number of vendors who are awarded contracts through the BQDM Program, but does not include direct customers and subcontractors. It is likely that the Commission is also interested in increasing the number of customers who provide distributed energy resources (such as commercial buildings providing demand response) and vendor subcontractors, and therefore the diversity index should be expanded to include these entities.

- Second, the diversity index, as currently defined, does not measure diversity of technologies. If this is a priority for the Commission, this measure of diversity should also be included in the index.

- Third, the specific calculation of the entropy index appears to reward equal contributions of capacity more than the number of vendors. That is, under the current metric definition, the Company would earn the maximum reward if two vendors each contribute 50% or if five vendors each contribute 20% of the capacity.

For these reasons, ConEd has proposed that Staff and the Company collaborate to modify the diversity index metric.

Illinois

In October 2011, the Energy Infrastructure Modernization Act (EIMA) was signed into law by Illinois Governor Pat Quinn. The law authorized 10-year, $2.6 billion smart grid investment by Commonwealth Edison (ComEd) designed to modernize and upgrade its electric system, including investments in smart grid infrastructure ranging from distribution automation and substation upgrades to smart meters for customers.

To ensure that customers receive benefits from the upgrades, the law also set reliability and other performance metrics to be achieved incrementally over ten years. These metrics include:

- 20% improvement in SAIDI
- 15% improvement in CAIDI
- 20% improvement in SAIFI
- Improvement in total number of customers who exceed service reliability targets by 75%
- 90% reduction in estimated bills
- 90% reduction in consumption on inactive meters
- 50% reduction in unaccounted for energy
- $30 million reduction in uncollectible expense

The performance incentives were set to be penalty only, with progress required in equal segments for each goal in each year. For each year that a goal is unmet, the utility faces a reduction in return on equity by 5-7 basis points per goal, with the penalty increasing over time. To avoid a penalty, 100% progress is required on reliability goals, and 95% progress required on other goals (220 ILCS 5 §16-108.5).

While explicitly addressing the basic aspects of electricity delivery listed above, the performance incentive mechanisms established by EIMA failed to address numerous other potential benefits of smart grid investments for consumers and the environment. For this reason, several consumer and environmental groups initiated discussions with ComEd to track numerous additional performance metrics.

Expansion of Performance Metrics

In 2013 environmental and consumer groups reached an agreement with ComEd to track numerous additional performance metrics. The list of performance metrics co-developed by the utility and stakeholders is extensive, and includes the following (ComEd 2014):

- Reductions in greenhouse gas emissions (as measured through load shifting, system peak reductions, and reduced truck rolls due to smart meters)
- Load served by distributed resources

- Time required to connect distributed resources to grid
- Peak load reductions (enabled by demand response)
- Products with grid interoperability (retail product market animation)
- Customers enrolled in time-varying rates (e.g., peak time rebates)
- Customer awareness and use of ComEd's web portal for viewing usage information

Although these performance metrics do not include any rewards or penalties, they provide valuable information for regulators and stakeholders to monitor whether customers are receiving the full benefit of the multi-billion dollar smart grid infrastructure investment. In addition, these metrics provide valuable information going forward for regulators if it is determined that a financial reward or penalty is warranted.

Metric Definitions

More than sixty performance metrics were developed to be tracked. The table below lists and defines many of these metrics. A nearly complete list can be found in ComEd's 2014 Smart Grid Progress Report, while the greenhouse gas metric details were filed in Illinois Commerce Commission Case Number 14-0555.

Table 21. Selected Smart Grid Metrics in Illinois

Customers enrolled in Peak Time Rebate, Real Time Pricing, and other dynamic and time variant prices	Residential Customers: Number of customers on a time-variant or dynamic pricing tariff offered by ComEd. Expressed also as a percentage of customers in each delivery class.
	Residential Customers: Number of customers served by retail electric suppliers for which the supplier has requested monthly Electronic Data Interchange delivery of interval data. Expressed also as a percentage of customers taking supply from a retail electric supplier in each delivery class.
	Small Commercial Customers: Number of customers on a time-variant or dynamic pricing tariff offered by ComEd. Expressed also as a percentage of customers in the delivery class.
	Small Commercial Customers: Number of customers served by retail electric suppliers for which the supplier has requested monthly Electronic Data interchange delivery of interval data. Expressed also as a percentage of customers taking supply from a retail electric supplier in the delivery class.
Customer-side-of-the-meter devices sending or receiving grid related signals	Number of ComEd AMI meters with consumer devices registered to operate with the Home Area Network ("HAN") chip by tariffs under which customer receives delivery.
AMI Meter failures	Number of advanced meter malfunctions where customer electric service is disrupted.

Customers with net metering	Number of customers enrolled on Net Metering tariff and the total aggregate capacity of the group.
Peak load reductions enabled by demand response programs	Load impact in MW of peak load reduction from the summer peak due to AMI enabled, ComEd administered demand response programs such as the PTS program as a percentage of all demand response in ComEd's portfolio.
Customer Complaints	Number of formal ICC complaints, informal ICC complaints, and complaints escalated to ComEd's Customer Relations or Customer Experience departments related to AMI Meter deployment, broken down by type of complaint and resolution. AMI Meter deployment includes AMI Meter installation, functioning or accuracy of the AMI meter, and HAN device registration.
Customer premises capable of receiving information from the grid	Number of installed AMI Meters as of the last day of the calendar year that communicate back to the head end system.
	Number of installed AMI Meters as of the last day of the calendar year that communicate back to the head end system, divided by the total number of AMI meters installed.
	Number of customers who have accessed the web-based portal as of the last day of the calendar year as a percentage of customers with AMI Meters and as a percentage of ComEd customers in that delivery class.
	Number of customers who can directly access their usage data as of the last day of the calendar year as a percentage of customers with AMI Meters and as a percentage of ComEd customers in that delivery class.
Peak load reductions enabled by demand response programs	Load impact in MW of peak load reduction from the summer peak due to AMI enabled, ComEd administered demand response programs as a percentage of all demand response in ComEd's portfolio.
Reduction in greenhouse gas emissions enabled by smart grid	Load shifting: ComEd will calculate marginal emissions changes due to load shifting for smart meter customers versus non-smart meter customers at an hourly level.
	Reduction in system peak: ComEd will partner with a third-party entity to conduct a dispatch study of the impact of load shifting and peak load reduction enabled by smart meters, including increased adoption of electric vehicles, on PJM's system, and determine a GHG metric around resulting changes in generator dispatch and expected plant closures.
	Reduced truck rolls: ComEd will compare the aggregate annual GHG emissions of all meter reading vehicles assigned to a specific operating center in the year in which Smart Meters are deployed in that same operating center, to the average aggregate annual GHG emissions of the three years prior to the year in which Smart Meter installation for that specific operating center is completed. GHG emissions will be calculated by measuring fuel consumption and converting into fuel emissions via the Climate Registry emission factor.

Distributed generation projects	Number of locations and total MWs of customer owned distributed generation connected to the transmission or distribution system, broken down by connection to transmission and distribution system.
	Number of locations and total MWs of customer owned distributed generation connected to the transmission or distribution system, broken down by connection to transmission and distribution system.
Load served by distributed resources	Total sales of electricity to the grid from distributed generation (Rider POG or POG-NM customers) divided by zone energy plus distributed generation sales, with all data provided in sortable format.
System load factor and load factor by customer class	Total annual consumption for AMI meters (including, separately, small commercial customers) divided by the average demand across all AMI meters over the 5 peak hours multiplied by 8760 hours by customer class.
Products with end-to-end interoperability certification	ComEd will conduct an annual survey through a third-party provider to evaluate how products are being introduced in the smart grid enabled marketplace.
Network nodes and customer interfaces monitored in "real time"	Network nodes and customer interfaces monitored in "real time"
Grid connected energy storage interconnected to utility facilities at the transmission or distribution system level	Number of locations and total MWs of utility owned or operated energy storage interconnected to the transmission or distribution system as measured at storage device electricity output terminals.
	Number of locations and total MWs of utility owned or operated energy storage interconnected to the transmission or distribution system as measured at storage device electricity output terminals.
	ComEd will conduct an annual survey through a third-party provider to estimate similar measures of non-utility storage units.
Time required to connect distributed resources to grid	ComEd's response time to a distributed resource project application, and time from receipt of application until energy flows from project to distribution grid.
	ComEd's response time to a distributed resource project application, and time from receipt of application until energy flows from project to transmission grid.
Grid assets that are monitored, controlled, or automated	Number and percentage of ComEd substations (Distribution Center Substations ("DCs"), Substations ("SSs") Transmission Substations ("TSSs") and Transmission Distribution Centers ("TDCs")) monitored or controlled via Supervisory Control and Data Acquisition ("SCADA") systems.
	Number and percentage of ComEd distribution circuits (4kV, 12kV and 34kV) equipped with automation or remote control equipment including monitor or control via SCADA systems.

Customers connected per automated circuit segment	Average number of customers per automated three phase 12kV line segment. (An "automated line segment" is a segment of 12 kV three phase mainline circuit between automated devices which include circuit breakers, reclosers, automated switches, etc.)
Improvement in line loss reductions enabled by smart grid technology	Stakeholders agreed upon several research priorities for research about line loss reductions. ComEd is conducting a feasibility study regarding use of Voltage Optimization. Voltage Optimization is combination of Conservation Voltage Reduction and Volt-VAR Optimization. These programs are intended to reduce end use customer energy consumption and peak demand while also reducing utility distribution system energy losses.
Voltage and VAR controls	Number and percentage of distribution lines using sensing from an AMI meter as part of ComEd's voltage regulation scheme.
Tracking Actual Costs	The actual cost of the AMI deployment costs that ComEd has incurred, including both one-time and on-going operating costs.
Customer Applications	Bill impacts associated with the costs for implementation of ComEd's AMI Plan for low, average, and higher usage level customers pursuant to approved rates and surcharges.
	Number of customers that have created and viewed an account on ComEd.com – by usage levels, customer class, and low income customers. An account on ComEd.com is necessary for viewing the web portal.
	Number of customers with ComEd.com accounts that have viewed the web portal - by usage levels, customer class, and low income customers
	Change in customers' energy consumption for customers that have viewed the web portal. ComEd will work with the web presentment vendor to define business processes necessary to track an energy usage impact of accessing the web portal.
	Number of customers enrolled in the Residential Real Time Pricing ("RRTP") program (ComEd's hourly pricing program) by usage levels, customer class, and low income customers.
	Number of customers enrolled in ComEd's PTR program by usage levels, customer class, and low income customers.
Customer Outreach & Education	Awareness and Education - Awareness and understanding of AMI technology and benefits (survey metric)

Hawaii

In 2010, Hawaii adopted revenue decoupling for its electric utilities in order to encourage renewable resources, distributed generation, and energy efficiency. When it adopted the decoupling mechanism, the Commission declined to adopt any performance incentive mechanisms, as the decoupling mechanism did not place a hard cap on allowed revenues. In 2013, however, the Commission determined that it was appropriate to reexamine the decoupling mechanism, particularly its revenue adjustment mechanism, and determine whether any performance metrics or performance incentive mechanisms should be adopted.

Performance Metrics

Numerous parties suggested performance metrics for tracking the utilities' ability to achieve renewable energy goals, ensure reliability, and reduce costs. As a result, the Hawaii Public Utilities Commission adopted nearly 30 performance metrics, including:

- **System Reliability:** System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), and Momentary Average Interruption Frequency Index (MAIFI)
- **Generator Performance:** Equivalent Availability Factor (EAF), Equivalent Forced Outage Rate Demand (EFORd), Equivalent Forced Outage Factor (EFOF)
- **Independent Power Producer (IPP) energy:** Measured as IPP energy / Net to System Energy
- **Renewable Energy:** System renewable energy (excluding customer-sited generation), total renewable energy (including distributed generation), renewable energy curtailments, and RPS compliance
- **Safety:** Public safety incidents, employee injury and illness rate, employee lost time rate, emergency response time
- **Distributed Energy Resources:** Number of net metering program participants and capacity of net metering program, demand response and storage enrollments
- **Customer service:** call center performance, customer complaints, appointments met, metering and billing accuracy, survey responses
- **Cost:** Metrics providing breakdowns of the contributing cost components to customer rates, and unaccounted for energy (HI PUC 2014).

Further, the Commission ordered that these metrics be posted on the Companies' websites in order to facilitate ease of access for utility customers.

Proposed Performance Incentive Mechanisms

During the second phase of the proceeding, parties proposed various forms of revenue cap mechanisms together with performance incentive mechanisms thought to be readily quantifiable, objective, and immune from gaming. Proposals varied widely, from traditional reliability and call center performance incentive mechanisms, to innovative mechanisms targeting reductions in fossil fuel use and the quality of utility resource planning.

Blue Planet, an intervenor in the case, proposed two environmental performance incentive mechanisms:

1) Reduction in carbon intensity of generation (as measured from the current baseline trend), with a potential reward of up to three cents per share.

2) Interconnection and utilization of non-utility, non-fossil generation and demand response resources, with a potential reward of several cents per share.

The Consumer Advocate proposed several performance incentive mechanisms, the most innovative of which was a mechanism for measuring the quality of the utilities' resource planning process, including stakeholder engagement, range of resources modeled, and follow-through on previous plans. The basis for this performance incentive mechanism was the Commission's IRP Framework, which was initially adopted in 1992 and revised in 2011. This PIM is described in greater detail below.

<u>Resource Planning Performance Incentive Mechanism</u>

Under this PIM, performance will be scored based on compliance with six principles and their associated metrics:

1) **Stakeholder Engagement:** The planning process should allow for meaningful stakeholder involvement throughout the planning process, and should incorporate stakeholder recommendations in the planning process as appropriate.[31]

   Metrics: Whether stakeholder input was adequately considered in establishing:

   a. Planning objectives
   b. Range of scenarios
   c. Resource options
   d. Assumptions, risks, and constraints
   e. Screening of options
   f. Criteria for ranking of resource plans
   g. The choice of final plan

[31] This principle measures the extent to which the Companies have complied with the Framework requirement V.B.1.b, which states: "consider the input, comments and suggestions provided by Advisory Group members and the general public, to the extent feasible," as well as compliance with requirement V.C.4.a (identification of planning objectives with input from advisory group).

2) **Evaluation of Resources:** The planning process should investigate a wide array of existing and emerging supply-side resources, including generation, transmission, and distribution opportunities, including utility-side smart grid options; as well as a wide array of existing and emerging demand-side options such as energy efficiency, demand response, distributed generation, storage technologies, and customer-facing smart grid options.[32]

   Metrics:

   a. Were appropriate modeling tools used?
   b. Were existing system and conditions adequately characterized?
   c. Was the range of new resources considered adequate?
   d. Were new resource options analyzed on a consistent and comparable basis, using reasonable estimates of the benefits and costs?
   e. Was adequate analysis performed to determine the risks and constraints of new resources?
   f. Did the analysis produce credible and reasonable results?

3) **Resource Scenarios and Resource Plans:** The planning process should include a transparent approach to identifying a reasonable set of resource scenarios and resource plans. From this set, the resource plans should be transparently prioritized or ranked based on previously identified key criteria such as minimization of the present value of revenue requirements, meeting environmental goals, maximizing customer benefits, and balancing risks.[33]

   Metrics:

   a. Was an appropriate range of scenarios examined (e.g., appropriate incorporation of various uncertainties; were scenarios extremes, or did they resemble what might actually occur)?
   b. Was there evaluation of an appropriate number of resource plans to ensure results of the process are meaningful?
   c. Were the criteria for determining the best resource plan clearly articulated at the outset?

[32] This principle measures compliance with several of the Framework requirements identified in section V.C., including V.C.2 (“Characterization of existing system and conditions”), V.C.3 (“Identification of uncertainties and factors that affect utility planning”), V.C.5 (“Determination of planning scenarios and forecasts”), V.C.6 (“Identification of resource options”), V.C.7 (“Models”), and V.C.8 (“Analyses”).

[33] This principle measures compliance with Framework requirements V.C.8. (Analyses), V.C.6.d (screening out infeasible or inappropriate resource scenarios), V.C.4.b and V.C.4.c (use of planning principles), and V.C.9 (determination of resource plans).

d. Was the weighting and ranking to determine the best resource plans transparent and did it incorporated principles and objectives previously identified?
e. Was sufficient consideration given to whether resource plans are able to meet state energy policy goals?
f. Were measures and strategies identified to address limitations and constraints that may impact the utility's ability to achieve state energy policy goals.

4) **Action Plan:** The planning process should include an action plan that enables the utility to translate the results of its analyses into development of actual resources.[34]

Metrics:

a. Does the Action Plan articulate next steps for implementing those resources that will be implemented in the short-term?

b. Does the Action Plan identify and address barriers to developing identified short-term resources?

5) **Strategic Planning:** This principle is intended to ensure that the companies' investments are guided by a long-term strategic vision that addresses the challenges faced by the companies and positions them to allow for agile response to changing system conditions.[35]

Metrics:

a. Do the companies clearly define a long-term strategic vision?
b. Does the strategic vision discuss steps that the companies need to take in order to move toward a more sustainable business model?
c. Does the strategic vision discuss the companies' strategy for ensuring that the investments made will enable the Companies to respond with agility to a range of possible future circumstances?
d. Are specific desired outcomes defined and initiatives identified to achieve such outcomes?

6) **Follow-Through on Previous Action Plans:** Demonstrated progress should be made in undertaking and successfully completing initiatives identified in the previous action plan. The companies should not be penalized for making prudent adjustments to the action plan in light of new information or changed circumstances, but any such changes must be sufficiently justified by the companies.

[34] This principle measures compliance with Framework requirements V.C.9.

[35] This principle addresses the desire of the Commission to ensure that the Companies face adequate "incentives to make necessary and/or appropriate changes to utility strategic plans and action plans," as evidenced by this being a major topic for comment in Order No. 31635.

Metrics:

Metrics should be set at the conclusion of each major planning process, based on the specific investments, activities, and costs identified in the action plan. How well these are achieved will then be evaluated at the commencement of the following planning process.

Example: Did the Companies develop X resource in Y timeframe within Z cost?

Utility performance on each metric would be rated as “inadequate,” “adequate,” or “exemplary.” A rating of “inadequate” would correspond to a score of 1.0, while “exemplary” would correspond to a score of 3.0. The scores for each metric would then be averaged for each principle.

The overall scorecard would be completed by an independent evaluator for the IRP process or similar entity in another planning process. The scorecard would be completed by the independent evaluator through a two-step process:

1) For the first principle regarding stakeholder engagement, stakeholders would complete a survey. If a stakeholder wished to score performance on a metric as either “inadequate” or “exemplary,” the stakeholder would be required to provide a detailed explanation describing their rationale. The independent evaluator would then review all of the stakeholder scores and assign a composite score for each metric, taking into account the evidence presented by stakeholders.

2) The independent evaluator would conduct an evaluation of the planning process and score the companies’ performance on each metric.

The scoring of the companies’ planning performance would not replace the current evaluation process in which the independent evaluator files interim reports and a certification report to the commission, but would occur in addition to this process. The PIM scorecard would serve to summarize the overall conclusions of the independent evaluator.

The completed scorecard would then be filed together with any other final certification or process report by the independent evaluator. The companies would then be allowed to respond to and rebut the scores received. The commission may, at its discretion, also allow other stakeholders to comment on the scorecard and the companies’ rebuttal. After considering any responses, the commission would then issue a final ruling regarding any penalty or reward.

Current Status of Performance Incentive Mechanisms

As of this writing, the commission had yet to issue an order regarding the proposed performance incentive mechanisms.

Performance Incentives Related to Fuel Adjustment Clauses

Fuel adjustment clauses have been widely adopted in many states to reduce the need for frequent rate cases due to fluctuations in fuel costs. However, these fuel adjustment clauses can reduce the incentive for utilities to operate efficiently, and can skew utilities' resource investment decisions, as the utilities are insulated from fuel price volatility. To address this, some jurisdictions modified their fuel cost pass-through mechanisms to allow only partial pass-through, or to make the pass-through contingent on the utility achieving a certain level of power plant efficiency. For example, prior to restructuring, New York adopted a mechanism by which utilities would absorb a portion (ranging from 20% to 40%) of fuel costs above its forecast. If costs came in below the forecast, the utility would retain a portion (20% to 40%) of the savings (Knittel 2002).

In Hawaii, the Energy Cost Adjustment Clause (ECAC) contains a heat rate efficiency factor. However, concerns were raised that the fixed sales target heat rate would penalize the utilities for introducing renewable energy, as lower capacity factors and higher ramping requirements can negatively impact thermal units' heat rates. In order to avoid the resulting disincentive for efficiency and renewable energy, a deadband of +/- 50 Btu/kWh sales was added to the heat rate target, and an agreement was reached to revisit the heat rate target upon the future addition of larger increments of renewable resources.

Conditioning cost recovery on power plant efficiency or using shared savings mechanisms can help distribute risk between the utility and ratepayers, and have been shown to be effective for improving power plant efficiency. A 2002 study analyzed the impacts of modified fuel adjustment clauses by comparing the efficiency of power plants under a full fuel cost adjustment clause with the efficiency of plants under a modified mechanism in which the utility must bear some of the risk for fuel cost overruns and can keep a portion of such savings. The author found that modified fuel adjustment clauses resulted in 9 percent more output produced for a given amount of input than mechanisms that passed through all of the fuel costs (Knittel 2002). This finding suggests that full fuel adjustment clauses do not encourage efficiency, but that a modified approach that incorporates shared savings can improve efficiency.

On a cautionary note, shared savings approaches related to fuel costs can be vulnerable to manipulation. For example, Nicor Gas, the largest gas utility in Illinois, has been ordered to refund more than $72 million to ratepayers due to allegations of fraud. The utility operated under an incentive that set a gas cost benchmark, and then allowed Nicor to keep half of any savings it achieved. According to allegations, the company manipulated its gas storage operation by improperly releasing low-cost gas put in storage under very low prices years before to artificially produce "savings" (Daniels 2013).

FERC's Bonus ROE for Transmission Projects

Pursuant to the Energy Policy Act of 2005, the Federal Energy Regulatory Commission (FERC) developed incentive-based rate treatments for transmission investments. As part of FERC's Order No. 679, transmission developers (utilities and stand-alone transmission companies) received higher rates of return on equity for new transmission investment in order to improve reliability and reduce congestion in order to lower delivered energy costs.

In practice, however, the incentive may have had effect of increasing delivered energy costs. By applying the ROE adder to the project's actual costs, developers were given a perverse incentive to *increase* the project costs (through, for example, delaying the construction), because they would earn the higher ROE on the total costs of the project. In this way, the incentive actually rewarded projects that came in over budget (American Forest & Paper Association, et al. 2011). It has been estimated that consumers in New England will pay more than an additional $100 million in adder charges for transmission projects because these projects have greatly exceeded their original costs (New England Conference of Public Utility Commissioners v. Bangor Hydro-Electric Co 2008).

Compounding this effect was the inability to demonstrate that the incentive would result in net benefits, as the Order did not require quantifying the benefits in relationship to the costs of the incentives. Further, applicants seeking the incentives were not required to show that the project would not be developed without the incentives (American Forest & Paper Association, et al. 2011).

Jim Tracy, Sacramento Municipal Utility District Chief Financial Officer, was one of many interveners who submitted comments in response to the FERC's Notice of Inquiry regarding the incentive mechanism. Having been involved in financing a large number of infrastructure projects, including transmission, distribution, and generation projects, Mr. Tracy noted that even if the net impact of the incentive was positive, the "costs of the incentives were almost certainly more than needed" (American Forest & Paper Association, et al. 2011, 143). He further commented that Commission's incentive rate may have resulted in excess transmission capacity.

According to Mr. Tracy, lenders are not influenced by higher rates of return for specific types of projects, but rather by the availability of mechanisms that reduce the risk that revenues will be interrupted during the recovery period. Further, because a utility's investment funds are limited, higher returns on certain types of projects can result in skewing the utility's investment choices away from alternatives that may be better for ratepayers (American Forest & Paper Association, et al. 2011).

APPENDIX B – DATA SOURCES AND AVAILABILITY

The following tables contain data sources for the metrics discussed in this handbook. Table 22 includes metrics, metric formulas, and data sources, and Table 23 includes notes about the availability of data and weblinks. Note that the data sources presented below may not provide all the data needed for performance metrics, and we have not assessed the quality or reliability of the data in these sources.

Many of the metrics discussed in this report can be obtained or calculated using data from federal agencies and other national organizations. Where data are not available from a national source, regulators can collect them directly from their utilities (indicated by "Collect from utility" in the Data Source column). However, regulators should assure that the data collected from utilities are well-defined, consistent across utilities, and well understood, as discussed in Chapter 3.

Table 22. Metric Formulas and Data Sources

Performance Dimension	Metric or metric group	Metric formula	Data Source
Reliability	System Average Interruption Duration Index (SAIDI)	Total minutes of sustained customer interruptions / total number of customers	EIA Form 861
	System Average Interruption Frequency Index (SAIFI)	Total number of sustained customer interruptions / total number of customers	EIA Form 861
	Customer Average Interruption Duration Index (CAIDI)	Total minutes of sustained customer interruptions / total number of interruptions	Collect from utility
	Momentary Average Interruption Frequency Index (MAIFI)	Total number of momentary customer interruptions per year / total number of customers	Collect from utility
	Power quality	Numerous metrics indicating changes in voltage including transient change, sag, surge, undervoltage, harmonic distortion, noise, stability, and flicker.	Collect from utility
Employee Safety	Total Case Rate (TCR)	(Number of work-related deaths, days away from work, job transfers or restrictions, and other recordable injuries and illnesses times 200,000) / Employee hours worked[36]	OSHA Form 300

[36] 200,000 represents the number of working hours per year for 100 full-time equivalent employees (40 hours a week for 50 weeks). (U.S. BLS 2013)

Performance Dimension	Metric or metric group	Metric formula	Data Source
	Days Away, Restricted, and Transfer (DART) case rate	(Number of work-related days away from work and job transfers or restrictions times 200,000) / Employee hours worked	OSHA Form 300
	Days Away From Work (DAFWII) case rate	(Number of work-related days away from work times 200,000) / Employee hours worked	OSHA Form 300
Public safety	Incidents, injuries, and fatalities (electric)	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by type of activity	Collect from utility
	Emergency response time (electric)	Percent of electric emergency responses within 60 min. each year	
	Incidents, injuries, and fatalities (gas)	Number of incidents per year, by severity of outcome (non-injury, minor, severe, and fatal) and by apparent cause (corrosion, natural forces, excavation, other outside force, pipe/weld/joint/equipment failure, incorrect operation, other cause)	PHMSA Form F 7100.1
	Emergency response time (gas)	Average minutes for gas emergency response	Collect from utility
	Leak repair performance (gas)	Average days for repair of minor and non-hazardous leaks	
Customer Satisfaction	Call center answer speed	Percentage of calls answered within 30 seconds	Collect from utility
	Transaction surveys	Percentage of customers satisfied with their recent transaction with the utility	Collect from utility
	Customer complaints	Formal complaints to the Commission (number per 1,000 customers)	Collect from utility
	Order fulfillment	Speed with which orders for service installation and termination, outage responses, and meter re-reading are fulfilled	Collect from utility
	Missed appointments	Percentage of appointments not met for meter replacements, inspections, or any other appointments in which the customer is required to be on the premises	Collect from utility
	Avoided shutoffs and reconnections	Disconnects and reconnections avoided by customer percentage of income payment plans or other means	Collect from utility
	Residential customer satisfaction	Electric Utility Residential Customer Satisfaction index, Gas Utility Residential Customer Satisfaction index	J.D. Power Electric Utility Residential Customer Satisfaction Study^{SM}, J.D. Power Gas Utility Residential Customer Satisfaction Study^{SM}

Performance Dimension	Metric or metric group	Metric formula	Data Source
	Business customer satisfaction	Electric Utility Business Customer Satisfaction index, Gas Utility Business Customer Satisfaction index	J.D. Power Electric Utility Business Customer Satisfaction Study^{SM}, J.D. Power 2014 Gas Utility Business Customer Satisfaction Study^{SM}
Plant Performance	Fuel usage	Quantity of fuel burned	FERC Form 1
	Heat rate	Average BTU per kWh net generation	FERC Form 1
	Capacity factor	Average energy generated for a period / energy that could be generated at full nameplate capacity	FERC Form 1
Costs	Capacity costs	Cost per kW of installed capacity	FERC Form 1
	Total energy costs	Expenses per net kWh	FERC Form 1
	Fuel cost	Average cost of fuel per kWh net gen and per Million BTU; total fuel costs	FERC Form 1
	Effective resource planning*	Numerous metrics regarding incorporation of stakeholder input, consideration of all relevant resources, use of appropriate assumptions and modeling tools, etc.	third-party evaluator
	Cost-Effective Alternative Resources*	$/MW cost of alternative portfolio relative to the $/MW cost of traditional investment	Collect from utility
System Efficiency	Load factor	Sector avg load / sector peak load	Collect from utility
		Monthly system average load / monthly system peak load	FERC Form 1
	Usage per customer	Sector sales / sector number of customers	FERC Form 1 (electric), Form EIA-176 (gas)
	Aggregate Power Plant Efficiency	System average BTU per kWh net generation (heat rate)	FERC Form 1
		Equivalent Forced Outage Rate (EFOR) = Equivalent Forced Outage Hours / (Period Hours – Equivalent Scheduled Outage Hours)	NERC Generating Availability Data System
		EFORd: variant of EFOR, measuring the probability that a unit will not meet its generating requirements demand periods because of forced outages or derates	NERC Generating Availability Data System
		Weighted equivalent availability factor: over a given operating period, the capacity-weighted average fraction of time in which a fleet of generating units is available without any outages and equipment or seasonal deratings	NERC Generating Availability Data System
	Flexible Resources	MW of fast ramping capacity (load following resources capable of 15-minute ramping and regulation resources capable of 1-minute ramping)	Collect from utility
	System losses	Total electricity losses / MWh generation, excluding station use	FERC Form 1
		Total gas losses / total sales	Form EIA-176

Performance Dimension	Metric or metric group	Metric formula	Data Source
Customer Engagement	Energy efficiency (EE)	Percent of customers per year participating in EE programs	Collect from utility
		Annual and lifecycle energy savings	EIA Form 861 (electric), collect from utility (gas)
		Annual and lifecycle peak demand savings (MW)	EIA Form 861
		Program costs per unit of energy saved (MWh or therm)	EIA Form 861 (electric), collect from utility (gas)
	Demand response (DR)	Percent of customers per year	EIA Form 861 and FERC F1
		Number of customers enrolled	EIA Form 861
		MWh of DR provided over past year	EIA Form 861
		Potential and actual peak demand savings (MW)	EIA Form 861
	Distributed generation (DG)	Number of installations per year	Collect from utility
		Net metering installed capacity (MW)	EIA Form 861
		Net metering MWh sold back to utility	EIA Form 861
		Net metering number of customers	EIA Form 861
		MW installed by type (PV, CHP, small wind, etc.)	EIA Form 861
	Energy storage	Number of installations per year	Collect from utility
		MW installed by type (thermal, chemical, etc.)	Collect from utility
		Percent of customers with storage technologies enrolled in demand response programs	Collect from utility
	Electric vehicles (EVs)	Number of EVs added to the grid each year	Collect from utility
		Percent customers with EVs enrolled in DR programs	Collect from utility
	Information availability	Number of customers able to access daily usage data via a web portal	EIA Form 861
		Percent of customers with access to hourly or sub-hourly usage data via web	Collect from utility
	Time-varying rates	Number of customers on time-varying rates / total customers	EIA Form 861
Network Support Services	Advanced metering capabilities	Number of customers with AMI and AMR	EIA Form 861
		Energy served through AMI	EIA Form 861
	Interconnection support	Average days for customer interconnection	Collect from utility
		Customer satisfaction with interconnect process	Collect from utility
	Third party access	Open and interoperable smart grid infrastructure that facilitates third-party devices	Collect from utility
		Third party vendor satisfaction with utility interaction	Collect from utility
	Provision of customer data	Customers able to authorize third-party access electronically	Collect from utility
		Percent of customers who have authorized third-party access	Collect from utility
		Third party data access at same granularity and speed as customers	Collect from utility

Performance Dimension	Metric or metric group	Metric formula	Data Source
Environmental Goals	SO_2 Emissions	Tons per year	EPA Air Markets Program Data
	Avg NOx Rate	lbs/MMBtu	EPA Air Markets Program Data
	CO_2 emissions	Tons CO_2 per year	EPA Air Markets Program Data
	Carbon intensity	Tons CO_2 / customer	EPA Air Markets Program Data and EIA 861
	System carbon emission rate	Tons CO_2 / MWh sold	EPA Air Markets Program Data and EIA 861
	Clean Power Plan (CPP) emission rate	lbs CO_2 from fossil generators / (Fossil Fuel Generation (MWh) + 5.8% Nuclear Generation (MWh) + Renewable Generation (MWh) + Cumulative Energy Efficiency (MWh))	Collect from utility
	Fossil carbon emission rate	Tons CO_2 / MWh fossil generation	EPA Air Markets Program Data and EIA 861
	Fossil generation	Fossil percent of total generation	EIA Form 923 and EIA Form 860
	Renewable generation	Renewable percent of total generation	EIA Form 923 and EIA Form 860

**See Appendix A, New York and Hawaii case studies, for more information on these metrics.*

Table 23. Data Sources and Notes on Availability

Source	Notes on Availability	Link to Data
EIA Form 176	Form EIA-176 is designed to collect data on natural, synthetic, and other supplemental gas supplies, disposition, and certain revenues by state. It must be completed by interstate and intrastate natural gas pipeline companies; gas distribution companies; underground gas storage operators; synthetic natural gas plant operators; field, well, or processing plant operators that deliver natural gas directly to consumers (including their own industrial facilities) other than for lease or plant use or processing; field, well, or processing plant operators that transport gas to, across, or from a state border through field or gathering facilities; and liquefied natural gas (LNG) storage operators, both peaking facilities and marine terminals. (U.S. EIA 2015a)	http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP1
EIA Form 860	Form EIA-860 collects data on the status of existing, grid connected electric generating plants with a nameplate capacity of 1 MW or greater and associated equipment (including generators, boilers, cooling systems and air emission control systems) in the United States, and those scheduled for initial commercial operation within 10 years (coal or nuclear) or 5 years (other energy sources). (U.S. EIA 2015b)	http://www.eia.gov/electricity/data/eia860/
EIA Form 861	All electric power industry entities complete 861, including: electric utilities, all DSM Program Managers, wholesale power marketers, energy service providers (registered with the states), and electric power producers. (U.S. EIA 2014c)	http://www.eia.gov/electricity/data/eia861/
EIA Form 923	Form EIA-923 collects information on the operation of electric power plants and combined heat and power (CHP) plants in the United States. Form EIA-923 is a mandatory report for all grid-connected electric power and CHP plants that have a total generator nameplate capacity (sum for generators at a single site) of 1 MW or greater. (U.S. EIA 2015b)	http://www.eia.gov/electricity/data/eia923/
EPA Air Markets Program Data	Data are available for power plants that are subject to various market-based regulatory programs, including the Acid Rain Program, NOx Budget Trading Program, and Clean Air Interstate Rule.	http://ampd.epa.gov/ampd/QueryToolie.html
FERC Form 1	FERC Form 1 is required for each major electric utility, licensees, or other (as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101)). Major is defined as having in each of the three previous calendar years, sales or transmission service that exceeds one of the following: (1) 1,000,000 MWh or more of total annual sales; (2) 100 MWh of annual sales for resale; (3) 500 MWh of annual power exchange delivered; or (4) 500 MWh of annual wheeling for others (deliveries plus losses). (FERC 2015)	http://www.ferc.gov/docs-filing/forms/form-1/data.asp

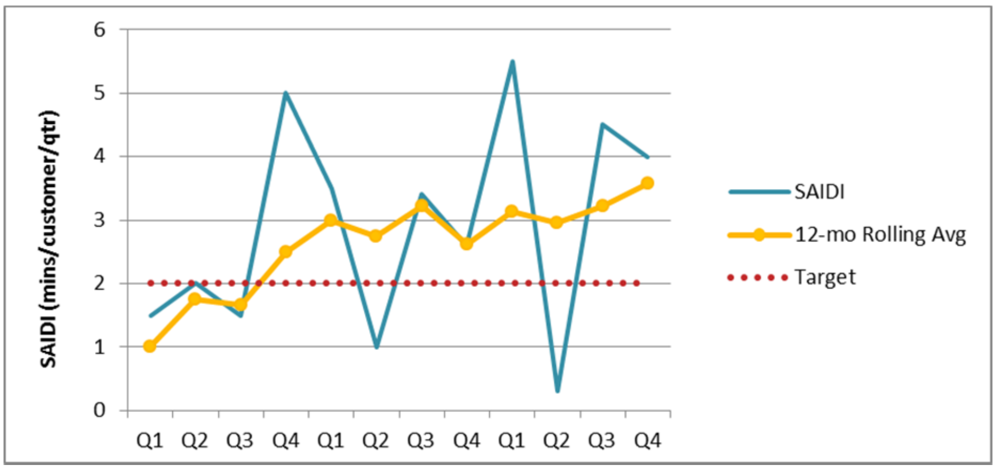
J.D. Power Electric Utility Business Customer Satisfaction Study℠	Within each of the four geographic regions included in the study, utility providers are classified into one of two segments: large (serving 85,000 or more business customers) and midsize (serving between 25,000 and 84,999 business customers). The study is conducted annually. The 2014 Electric Utility Business Customer Satisfaction Study is based on responses from > 23,700 online interviews with business customers that spend at least $250 monthly on electricity.	http://www.jdpower.com/press-releases/2014-electric-utility-business-customer-satisfaction-study
J.D. Power Electric Utility Residential Customer Satisfaction Study℠	The Study ranks midsize and large utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 100,000 and 499,999 residential customers, while companies in the large utility segment serve 500,000 or more residential customers. The Study has been conducted annually for 16 years. The 2014 Study was based on responses from 104,460 online interviews conducted from July 2013 - May 2014 among residential customers of the 138 largest electric utility brands across the U.S.	http://www.jdpower.com/press-releases/2014-electric-utility-residential-customer-satisfaction-study
J.D. Power Gas Utility Business Customer Satisfaction Study℠	The study measures business customers' satisfaction with the nation's 55 largest gas utilities in four U.S. geographic regions: East, Midwest, South, and West. The study examines satisfaction across six factors—billing and payment; corporate citizenship; price; communications; customer service; and field service.	http://www.jdpower.com/resource/us-gas-utility-business-customer-satisfaction-study
J.D. Power Gas Utility Residential Customer Satisfaction Study℠	The study ranks large and midsize utility companies in four geographic regions: East, Midwest, South and West. Companies in the midsize utility segment serve between 125,000 and 399,999 residential customers, and companies in the large utility segment serve 400,000 or more residential customers. The Study has been conducted annually for 13 years. The 2014 Gas Utility Residential Customer Satisfaction Study is based on more than 69,800 responses from residential customers of 83 large and midsize gas utilities across the continental United States. The study was fielded between September 2013 and July 2014.	http://www.jdpower.com/press-releases/2014-gas-utility-residential-customer-satisfaction-study
NERC Generating Availability Data System	For conventional generating units with a nameplate capacity of 20 MW and larger, GADS reporting is mandatory. Renewable generation (i.e., wind and solar) is not required to report. Conventional generating units less than 20 MW nameplate are invited to report to GADS on a voluntary basis.	http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx
OSHA Form 300	The Occupational Safety and Health (OSH) Act of 1970 requires certain employers to prepare and maintain records of work-related injuries and illnesses. OSHA Form 300 is only available for a small portion of all private sector establishments in the U.S. (80,000 out of 7.5 million total establishments).	https://www.osha.gov/pls/odi/establishment_search.html, http://ogesdw.dol.gov/views/searchChooser.php
PHMSA Form F 7100.1	Title 49 of the Code of Federal Regulations (49 CFR Parts 191, 195) requires pipeline operators to submit incident reports within 30 days of a pipeline incident or accident. The CFR defines accidents and incidents, as well as criteria for submitting reports to the Office of Pipeline Safety.	http://www.phmsa.dot.gov/pipeline/library/data-stats

APPENDIX C – DASHBOARD EXAMPLES

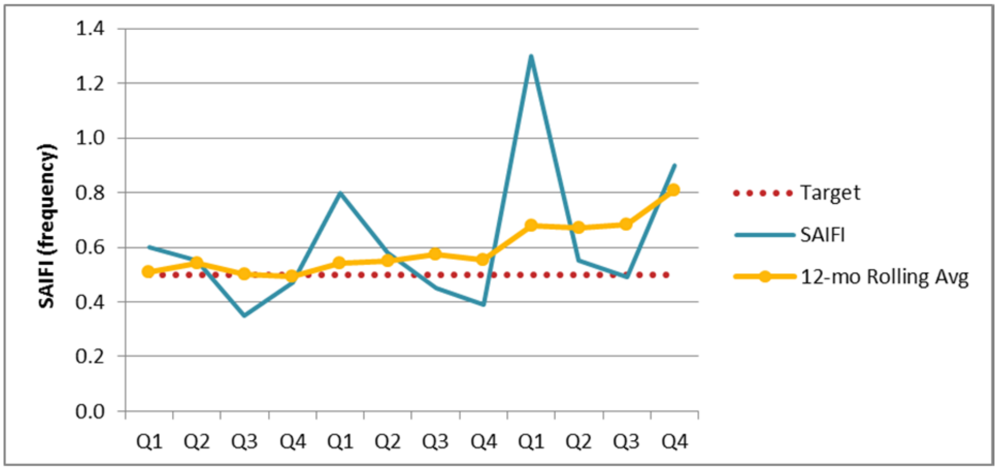
The following examples show how data dashboards can provide visual context for performance targets in terms of historical utility performance and trends. These examples are based on actual data (for unnamed utilities in western US states or on data for the entire United States) or they were fabricated for illustrative purposes.

Reliability

SAIDI is an indicator of sustained interruptions experienced by customers. SAIDI is defined as total minutes of sustained customer interruptions divided by total number of customers, over a period of time. This illustrative example shows a hypothetical utility's system wide SAIDI and 12 month rolling average over a three year period, along with its target.

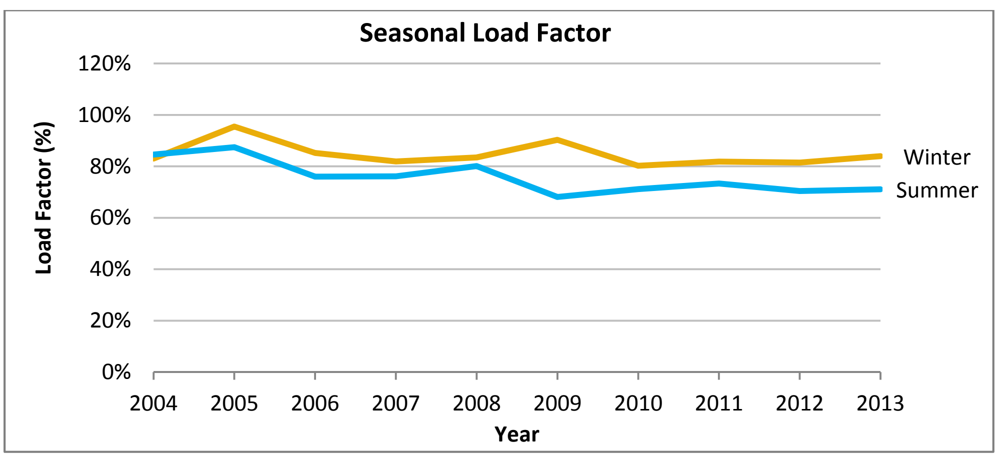


SAIFI is an indication of how many interruptions are experienced by customers over a period of time. SAIFI is defined as total number of sustained customer interruptions divided by total number of customers. This illustrative example shows a hypothetical utility's system wide SAIFI and 12 month rolling average over a three year period, and its performance target.



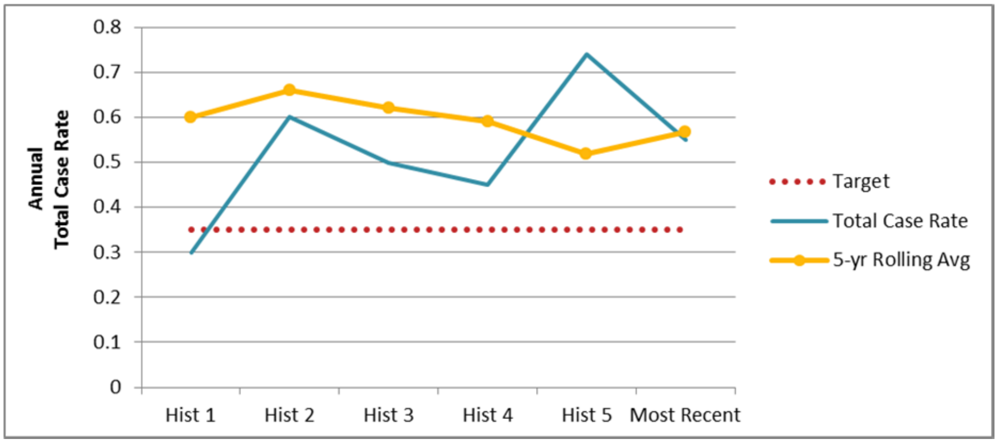
System Efficiency

As one metric for the efficient use of the electric system, load factor indicates the extent to which load occurs during peak periods. It is defined as the average load over a period of time divided by peak load. A dashboard can be used to show load factors for the entire system and for each customer sector over time. The example below shows the seasonal load factor for a western electric utility over ten years, obtained from FERC Form 1 data. Although FERC Form 1 provides energy and peak demand for the system as a whole, ideally load factors should be considered by consumer sector to allow for a targeted policy response.

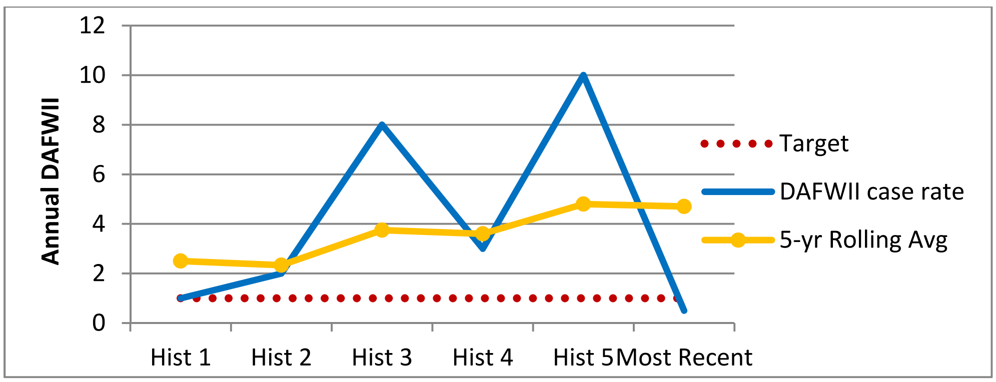


Safety

Employee safety can be measured using metrics. Standard metrics defined and reported by OSHA include work-related deaths, injuries, and illnesses (the Total Case Rate, or TCR); the Days Away from work, Restricted, or Transfer (DART) case rate; and the Days Away From Work (DAFWII) case rate. Because OSHA collects data from only a small fraction of companies, regulators should consider collecting data directly from utilities. Below is an illustrative example of a TCR for a hypothetical utility over a period of six years.

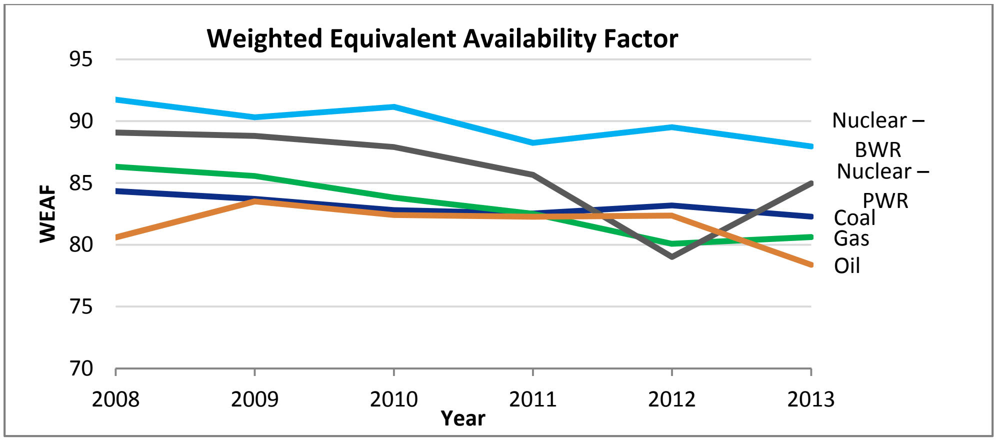


The following graph shows an illustrative example of a Days Away From Work (DAFWII) case rate over a period of six years for a hypothetical utility.

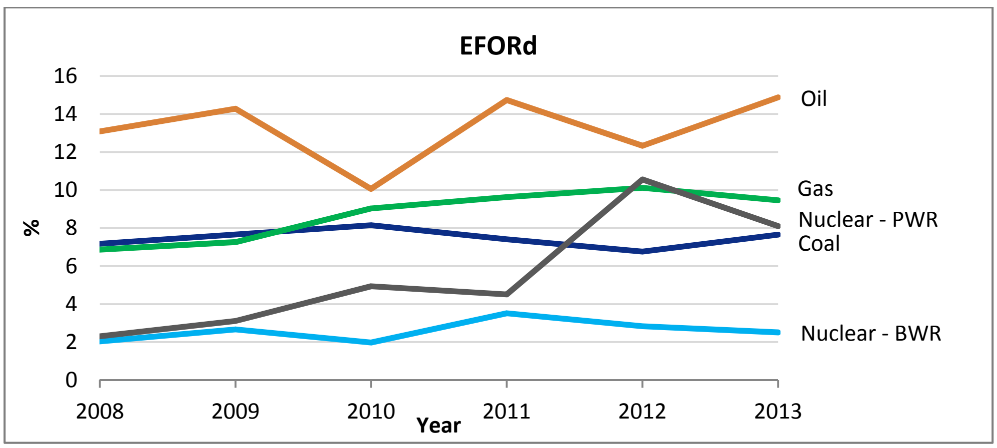


Power Plant Availability

Regulators often review the performance of individual power plants. However, regulators should consider the performance of the electric system as a whole, especially in the context of resource planning. The Weighted Equivalent Availability Factor (WEAF) is a metric indicating availability of supply side generation resources. Below is a graph showing the actual WEAF for the entire U.S. for six historical years, by fuel type.

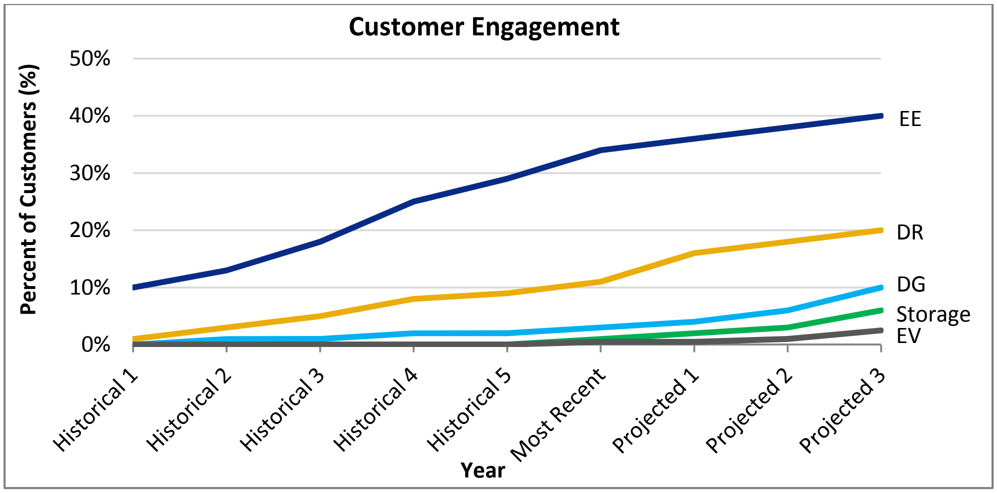


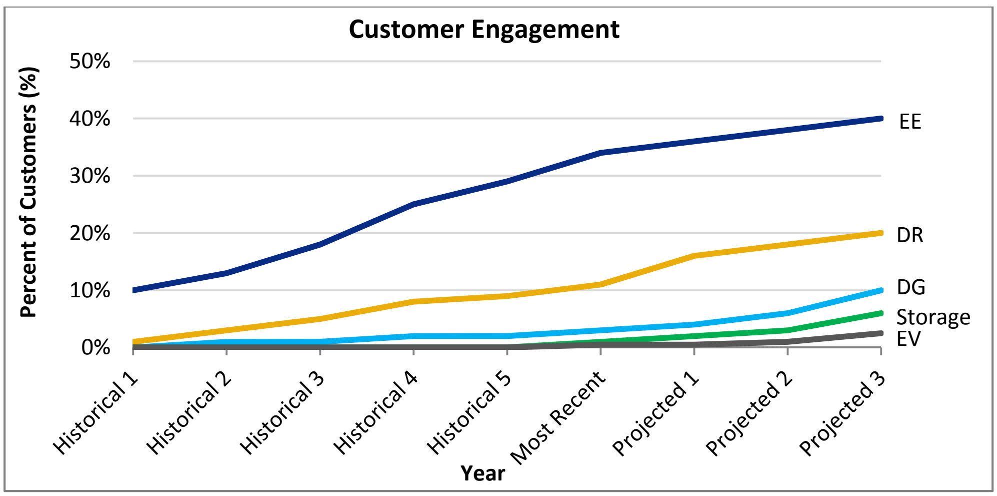
The Equivalent Forced Outage Rate Demand (EFORd) measures the probability that a unit (or group of units) will not meet demand periods for generating requirements because of forced outages or derates. Below, is a graph showing the actual EFORd by fuel type for the entire U.S. over six historical years.



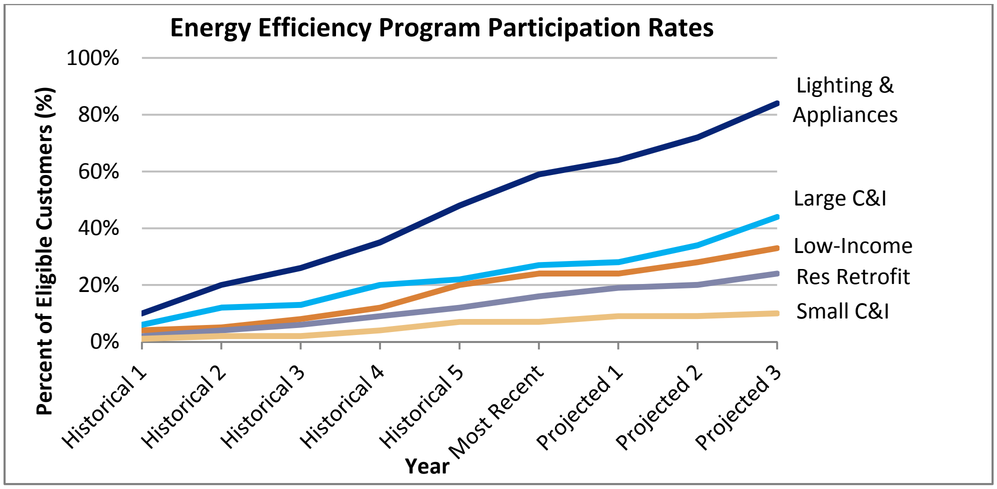
Customer Engagement

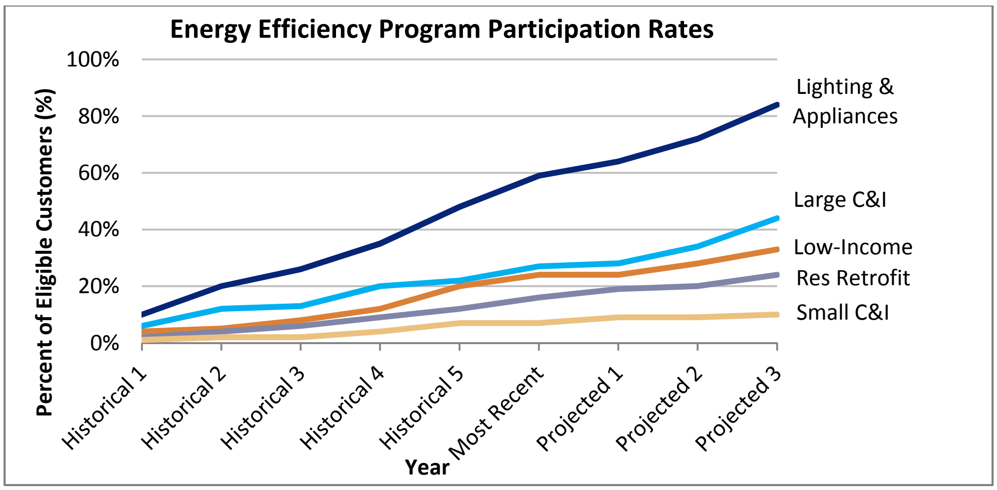
Customer engagement metrics indicate the extent to which customers are participating in demand-side programs or installing demand-side resources, which can reduce the need for new supply-side resources. The following graph shows historical and projected customer engagement for a hypothetical utility in five key areas: energy efficiency (EE), demand response (DR), distributed generation (DG), customer-sited energy storage, and electric vehicles (EV).





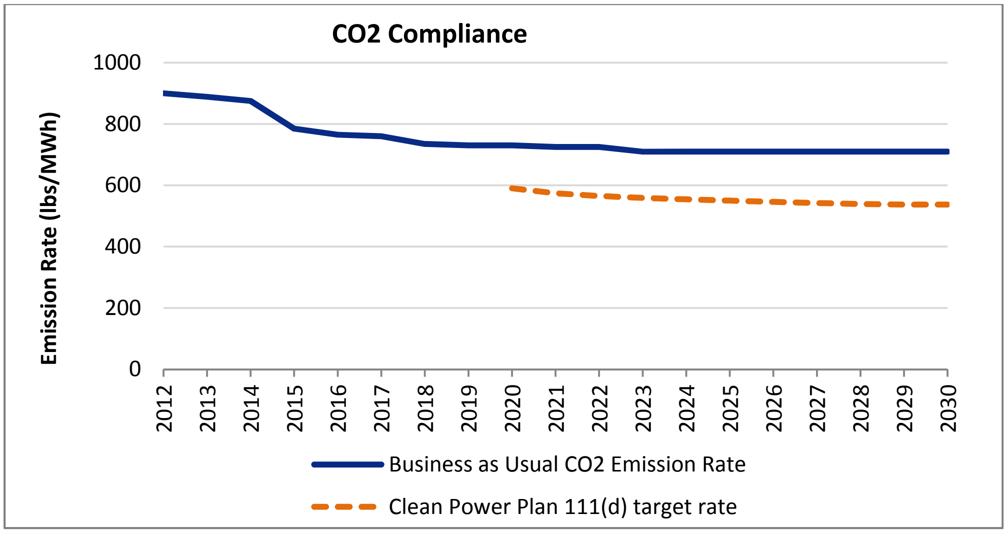
As an indication of which sectors are participating in energy efficiency programs, utilities and regulators may wish to examine participation in programs targeting specific customer segments, as a percentage of customers eligible for those programs. The following graph shows historical and projected participation rates for a hypothetical utility's lighting and appliances (for which data on participant customer types are rarely available), large commercial and industrial (C&I), low-income, residential (res) retrofit, and small C&I energy efficiency programs.



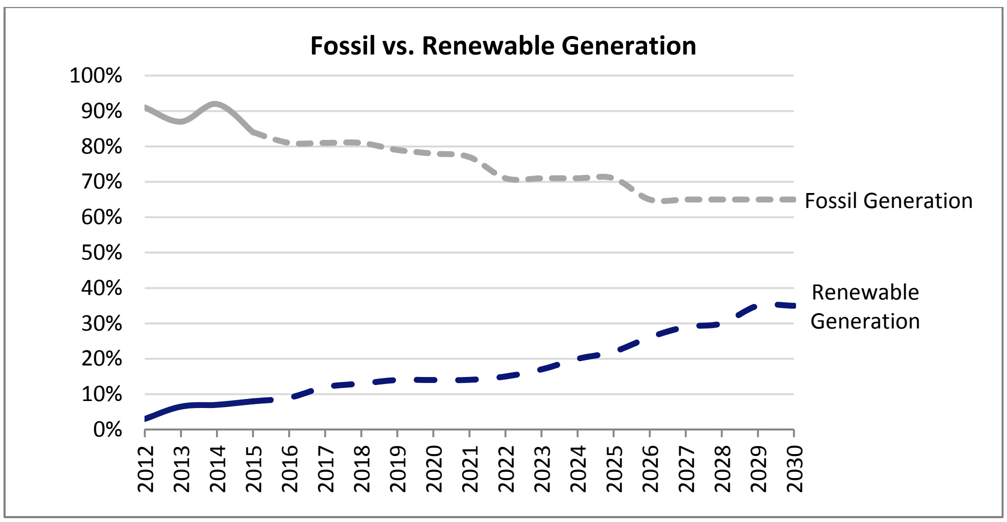


Environmental Goals

Environmental metrics indicate the extent to which the utility and its customers are reducing environmental impacts and can be particularly important with regard to ensuring that the state is on a path toward compliance with climate change regulations. Below is a graph showing the actual Clean Power Plan target CO2 rate for a western state, along with historical and hypothetical projected emissions rate under a business as usual scenario.



Below is an illustrative graph showing historical and projected fossil and renewable generation as a percent of total generation for a hypothetical utility.



Appendix D

ACCOUNTING AND FINANCIAL MATTERS

Appendix D1

EXISTING DEFERRAL ACCOUNTS

Appendix D1-1

FEI EXISTING DEFERRAL ACCOUNTS

1 # FEI EXISTING DEFERRAL ACCOUNTS

2 **Table A:D1-1-1: FEI Rate Base Deferral Accounts**

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Forecasting Variance Account	Midstream Cost Reconciliation Account (MCRA)	G-25-04; L-5-01; L-40-11	Captures the costs FEI incurs in performing the midstream function and the revenues collected through midstream rates. Gas Supply, in its midstream role, uses the pipeline and storage resources, spot and peaking purchases, and sale activities as approved in the Annual Contracting Plans to manage load variability. The MCRA accumulates any resulting cost variances, including any volume-related variances due to differences between the forecast and actual consumption. The resulting variances are taken into account when determining future midstream rates. In addition, price and volume variances between the forecast and actual amount of company use gas are booked against and managed through the MCRA.	Reviewed quarterly and adjusted on an annual basis. Recovered from customers over 2 years.
Forecasting Variance Account	Commodity Cost Reconciliation Account (CCRA)	G-25-04; L-5-01; L-40-11	Captures the costs incurred by FEI to purchase its portion of the baseload commodity supply under the Essential Services Model and the commodity recovery revenues received from sales customers choosing to remain on the utility standard rate offering. Commodity price-related variances collected in the CCRA are taken into account when determining future commodity rate changes. The commodity rate is reviewed on a quarterly basis, and typically reset when the commodity recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold, and the $/GJ value of the calculated rate change exceeds the minimum rate change threshold of $0.50/GJ.	Adjusted quarterly; recovered over a 12 month period from Quarter-end

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Forecasting Variance Account	Revenue Stabilization Adjustment Mechanism (RSAM)	G-59-94	Stabilizes the Company's delivery margin revenue from the Residential and Commercial customer classes. The RSAM enables FEI to record delivery margin revenue for these customer classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying from forecast, an entry is made to the RSAM account that adjusts revenue collected from customer rates from actual use to what customers would have paid based on forecast use.	2 years
Forecasting Variance Account	Interest on MCRA, CCRA, RSAM and Gas in Storage	G-7-03; G-141-09	Variances from the forecast CCRA, MCRA, RSAM and Gas In Storage balances attract interest at the Company's short-term borrowing rate. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers.	Same as respective margin account; Gas in Storage collected over 3 years
Forecasting Variance Account	Revelstoke Propane Cost Deferral Account	G-72-90; L-40-11	Captures the difference between the actual cost of propane and the amount recovered in rates, based on the approved reference price of propane. The propane reference price is reviewed on a quarterly basis, and typically reset when the propane recovery-to-cost ratio, on a 12-month prospective basis, falls outside the 0.95 to 1.05 threshold and the $/GJ value of the calculated rate change exceeds the minimum rate change threshold of $0.50/GJ.	Adjusted quarterly; recovered over a 12 month period from Quarter-end
Forecasting Variance Account	SCP Mitigation Revenues Variance Account	G-124-00; G-70-10	Captures any variation from the SCP revenues forecast and included in the determination of rates each year, and actual revenues received.	2 years
Forecasting Variance Account	Pension & OPEB Variance	G-51-03	Captures the variance between actual pension and OPEB expense and the amount forecast in rates.	3 years
Forecasting Variance Account	BCUC Levies Variance	G-112-04	Captures the variance between actual annual BCUC levies and the amount forecast in rates.	1 year

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Forecasting Variance Account	TESDA Overhead Allocation Variance	G-138-14	Captures the difference between the amount of actual indirect overhead incurred by FEI on behalf of FAES, and the amount embedded in approved O&M rates in the 2014-2019 PBR period only.	1 year
Benefits Matching Account	Demand-Side Management (DSM)	G-36-09; G-44-12; G-10-19	Captures up to $30 million annually in new expenditures on DSM activities. Also includes the amounts transferred from the non-rate base DSM account in the following year.	10 years
Benefits Matching Account	NGV Conversion Grants	G-98-99	Captures amounts awarded by FEI for NGV conversions for Rate Schedule 6 light duty customers.	5 years
Benefits Matching Account	Emissions Regulations	G-44-12	Captures potential compliance costs less revenues collected from credits related to Emissions Regulations, particularly the Emissions Trading Regulation and the Renewable and Low Carbon Fuel Requirements Regulation ("RLCFRR") which are aimed to reduce Greenhouse Gas ("GHG") emissions in BC.	5 years
Benefits Matching Account	On-Bill Financing Pilot Program	G-163-12; G-138-14	Captured the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries. One balance remaining.	Recovered directly from OBF customers over 10 years.
Benefits Matching Account	Greenhouse Gas Reduction Regulation Incentives	G-161-12; G-67-13; G-73-18	Captures all grants and costs, including a portion of application costs, related to Prescribed Undertakings 1 and 3.6 of the GGRR.	10 years
Benefits Matching Account	CNG and LNG Recoveries	G-128-11	Captures the incremental CNG and LNG fueling station recoveries received from fueling station volumes in excess of the minimum contract demand.	1 year
Benefits Matching Account	2016 Cost of Capital Application	G-86-15	Captured the costs related to the 2016 Cost of Capital proceeding.	3 years
Benefits Matching Account	2015-2019 Annual Review Costs	G-178-14	Captured the costs related to the 2015-2019 Annual Review proceedings.	1 year

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	2017 Rate Design Application	G-86-15	Captured the costs related to the 2017 Rate Design proceeding.	5 years
Benefits Matching Account	2017 Long Term Resource Plan Application	G-193-15	Captured the costs related to the 2017 Long Term Resource Plan proceeding.	3 years
Benefits Matching Account	2019-2022 DSM Expenditures Application Costs	G-237-18	Captures the costs related to the FEI 2019-2022 DSM Expenditures proceeding.	4 years
Benefits Matching Account	Whistler Pipeline Conversion	G-53-06; G-35-09; G-138-10	Captured the costs of converting Whistler customers from propane to natural gas.	20 years
Benefits Matching Account	2010-2011 Customer Service O&M and Cost Of Service	G-141-09; C-1-10; C-23-10	Captured all incremental costs associated with the project that were incurred prior to the project implementation date of January 1, 2012, as well as any amounts related to the timing of when the project was available for use compared to when it is actually added into rate base.	8 years
Benefits Matching Account	Gas Assets Records Project	G-44-12	Captured the Gas Asset Records Project costs.	5 years
Benefits Matching Account	BC OneCall Project	G-44-12	Captured the BCOneCall Project costs.	5 years
Benefits Matching Account	Gains and Losses on Asset Dispositions	G-141-09; G-44-12	Captured gains and losses on asset dispositions for 2010 and 2011.	10 years
Benefits Matching Account	Net Salvage Provision/Costs	G-44-12	Captures the annual negative salvage provision calculated using the approved negative salvage rates, offset by the actual net removal costs incurred.	n/a

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	PCEC Start Up Costs		Includes the unrecovered balance of the original amount of pre-start up costs of $1,754,000 incurred by PCEC to operate a portion of the pipeline facilities for several months prior to the “in-service” date of October 1, 1991.	40 years
Benefits Matching Account	2020 Revenue Requirement Proceeding	G-196-17	Captures external costs related to the 2020 MRP application and proceeding.	Will be requested in a future application.
Benefits Matching Account	City of Surrey Operating Terms Application Costs	G-196-17	Captures the costs related to the City of Surrey Operating Terms proceeding.	3 years
Other Account	Pension & OPEB Funding	G-135-99; G-141-09	Captures the difference between amounts funded by ratepayers for pension and OPEB and amounts actually paid out by the Company, on a net of tax basis.	Life of the Employee Future Benefits
Other Account	US GAAP Pension & OPEB Funded Status	G-44-12	Captures the accumulated other comprehensive income balance related to pensions and OPEBs, with an offsetting entry to the Pension and OPEB Funding deferral account. This deferral account will capture the changes in the accumulated other comprehensive income balance each year as determined by the external actuary. The Pension and OPEB funding account captures the funded status of pensions and OPEB.	n/a
Other Account	BFI Costs and Recoveries	G-86-15	Captures the revenues associated with the volumes in excess of BFI's take-or-pay commitment (related to the capital component of excess recoveries only) which may be credited back to BFI in the event that BFI is required to pay the un-depreciated capital cost of the fueling station if the contract buyout provision is exercised.	n/a
Other Account	Residual Delivery Rate Riders	G-196-17	Used to dispose of various rate rider deferral accounts which have small residual ending balances.	1 year
Other Account	BVA Balance Transfer	G-133-16	Captures all BVA related costs except for the supply ending inventory volume valued at the forecasted Jan. 1st BERC rate in the following year.	1 year

1 **Table A:D1-1-2: FEI Non Rate Base Deferral Accounts**

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Forecasting Variance Account	Biomethane Variance Account (BVA)	G-194-10; G-133-16	Captures the costs incurred to procure and process consumable Biomethane gas and the revenues collected through the Biomethane energy recovery component of rates. Beginning in 2016, this account will be re-based each year end to only include the remaining unsold biomethane inventory volume valued at the following year's Jan. 1 BERC rate. All remaining costs will be transferred to the BVA Balance Transfer deferral at year-end.	Reviewed quarterly and adjusted on an annual basis. Recovered from customers over 1 year.	None
Forecasting Variance Account	Flow-Through Account	G-162-14	Captures the annual variances between forecast and actual amounts for all costs and revenues which are flowed through on a forecast basis and which do not have a previously approved deferral account.	1 year	WACC
Forecasting Variance Account	Marketer Cost Variance	A-9-16	Captures and records any under or over recovery of gas marketer fees, compared to marketers O&M costs, to be recovered from or returned to gas marketers in the subsequent year through the annual fee adjustment starting on April 1, 2017. This deferral account is approved for a period of five years from 2017-2021.	Recovered directly from gas marketers over 1 year.	WACC
Rate Smoothing Account	2017-2018 Revenue Surplus	G-182-16; G-196-17	Captured the 2017 and 2018 revenue surpluses resulting from maintaining 2017 and 2018 delivery rates at 2016 levels.	Will be requested in a future application.	WACC
Benefits Matching Account	DSM Account	G-44-12; G-163-12; G-138-14; G-10-19	To capture the remaining portion of the actual DSM costs incurred up to the funding cap each year that are above the amount forecast in the rate base deferral account. These amounts are then transferred to the rate base DSM deferral account in the following year.	n/a	WACC

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Benefits Matching Account	PEC Pipeline Development Costs and Commitment Fees	G-66-13A	Captured the development costs and commitment fees paid by Pacific Energy Corporation (PEC) to FEI that enabled FEI to commence development work to provide natural gas transportation service to PEC under a long-term Transportation Services Agreement between FEI and PEC.	n/a	None
Benefits Matching Account	Transmission Integrity Management Capabilities CPCN Development Costs (TIMC)	G-237-18	Captures the development costs related to the future TIMC CPCN projects.	Will be requested in a future application.	WACC
Other Account	US GAAP Uncertain Tax Positions	G-44-12	Captures any ongoing differences that arise from the implementation of US GAAP Financial Accounting Standards Board Interpretation No. 48	n/a	None
Other Account	Mark to Market - Hedging Transactions	E-22-95	Approved to record the mark-to-market adjustment due to financial hedging transactions for System and Non-System Gas purchasing.	n/a	None
Other Account	Earnings Sharing Account	G-162-14	Captures the calculated annual earnings sharing under the 2014-2019 PBR Plan and under the 2020-2024 MRP Plan.	1 year	WACC

Appendix D1-2

FBC EXISTING DEFERRAL ACCOUNTS

FBC EXISTING DEFERRAL ACCOUNTS

Table A:D1-2-1: FBC Rate Base Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period
Benefits Matching Account	Demand Side Management	G-123-98; G-58-06	Captures the costs of FBC's DSM programs and initiatives to promote energy efficiency for customers.	10 years
Benefits Matching Account	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 Individual Debenture
Benefits Matching Account	Preliminary and Investigative Charges	Uniform System of Accounts Section 183	Costs incurred in determining the feasibility of projects for utility services, other than CPCN projects.	Transferred to CWIP upon project commencement
Other	Pension & OPEB Liability	G-184-10; G-107-15	Captures the difference between the actuarially determined expense and the contributions paid by the Company.	Life of the Employee Future Benefits

Table A:D1-2-2: FBC Non Rate Base Deferral Accounts

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Forecasting Variance Account	Flow-Through Account	G-163-14	Captures the annual variances between forecast and actual amounts for all costs and revenues which are flowed through on a forecast basis and which do not have a previously approved deferral account.	1 year	STI
Forecasting Variance Account	Pension & OPEB Variance	G-110-12; G-139-14	Captures the variance between actual pension and OPEB expense and the amount forecast in rates.	3 years	STI

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Rate Smoothing Account	2018-2019 Revenue Surplus	G-131-18; G-246-18	Captured the 2018 and 2019 net revenue surplus resulting from maintaining 2018 and 2019 rates at 2017 levels.	Will be requested in a future application.	WACD
Benefits Matching Account	CPCN Projects Preliminary Engineering	G-139-14	Captures preliminary costs including regulatory review and investigative engineering costs in the development of capital projects subject to CPCN applications.	Transferred to CWIP upon project approval.	WACD
Benefits Matching Account	Annual Reviews for 2015 - 2019 Rates	G-139-14	Captured external costs related to the Annual Reviews for 2015 through 2019 rates.	1 year	STI
Benefits Matching Account	2020 Revenue Requirements	G-38-18	Captures external costs related to the 2020 MRP application and proceeding.	Will be requested in a future application.	WACD
Benefits Matching Account	Self-Generation Policy Stage II	G-8-17	Captures external costs for development and regulatory review of Stage II of the Self-Generation Policy application.	1 year	STI
Benefits Matching Account	Net Metering Program Tariff Update	G-8-17	Captures external costs for development and regulatory review of the Net Metering tariff update.	1 year	STI
Benefits Matching Account	2018 DSM Expenditure Schedule	G-246-18	Captures external costs for development and regulatory review of the 2018 DSM Expenditure Schedule.	1 year	STI
Benefits Matching Account	Multi-year (2019-2022) DSM Expenditure Schedule	G-38-18; G-246-18	Captures external costs for development and regulatory review of the 2019-2022 DSM Expenditure Schedule.	4 years	WACD
Benefits Matching Account	Tariff Applications	G-38-18	Captures external costs for regulatory review of applications for new tariffs or for tariff revisions (excluding rate design applications).	1 year	STI
Benefits Matching Account	2017 Rate Design Application	G-202-15; G-246-18	Captures external costs for development and regulatory review of the 2017 Rate Design Application.	5 years	WACD

Type	Account Name	BCUC Order(s)	Description	Recovery Period	Return
Benefits Matching Account	Rate Design and Rates for EV DCFC Stations	G-246-18	Captures external costs related to the rate design and rates application for Electric Vehicle Direct Current Fast Charging Stations application.	Will be requested in a future application.	WACD
Benefits Matching Account	2016 Long Term Electric Resource Plan	G-107-15; G-38-18	Captures external costs for development and regulatory review of the 2016 LT Electric Resource Plan.	5 years	WACD
Benefits Matching Account	2018 Joint Use Pole Audit	G-38-18	Captures FBC's portion of costs to carry out the 2018 joint use pole audit.	5 years	WACD
Benefits Matching Account	On-Bill Financing (OBF) Participant Loans	G-163-12	Captures the principal loan balances provided to participating customers of the OBF Pilot Program and the applicable interest charges and recoveries.	Recovered directly from OBF customers over 10 years.	WACC
Other Account	Earnings Sharing Account	G-139-14	Captures the calculated annual earnings sharing under the 2014-2019 PBR Plan and under the 2020-2024 MRP Plan.	1 year	STI
Other Account	US GAAP Pension and OPEB Transitional Obligation	G-110-12	Recognizes the transitional obligation of pensions and OBEPs on transition to US GAAP effective January 1, 2012.	12 years	WACD
Other Account	Advanced Metering Infrastructure Radio-Off Shortfall	G-202-15; G-40-19	Captures the shortfall between actual O&M expense related to radio-off customers and the amounts recovered through tariff charges through December 31, 2019.	5 years	WACD
Other Account	BC Hydro Waneta 2017 Transaction	G-246-18	Captures external costs for FBC's participation in the BC Hydro Waneta 2017 Transaction proceeding.	1 year	STI
Other Account	Kettle Valley Future Site Expansion	G-47-13	Cost of land used to provide sufficient extra space for future site expansion, to be recovered from ratepayers when and if this portion of the site becomes used and useful.	none	none

Appendix D2

DEPRECIATION STUDY

Appendix D2-1

FEI 2017 DEPRECIATION STUDY

2017 Depreciation Study

Calculated Annual Depreciation Accrual Rates
As of December 31, 2017

Prepared February 2019

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CONCENTRIC
ADVISORS

February 15th, 2019

FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8

Attention: Lilyana Tabakova
Asset Accounting Manager

Dear Lilyana;

As requested, Concentric Advisors, ULC has developed annual depreciation accrual rates for FortisBC Energy Inc. for gas distribution plant in service as of December 31, 2017. The subsequent report presents a detailed description of the methods and parameters used in the formulation of depreciation life and net salvage estimates, as well as the calculations and tabulations of the service life, net salvage, and annual and accrued depreciation.

Concentric gratefully acknowledges the assistance of FortisBC Energy personnel in the completion of the report.

Respectfully submitted,

Larry E Kennedy
Vice President

LEK\bmw
Project No.70032

TABLE OF CONTENTS

CONCENTRIC ADVISORS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to FortisBC Energy Inc.'s ("FortisBC Energy" or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to all gas manufacturing, transmission, distribution and general plant accounts, as of December 31, 2017. This study determines annual depreciation accrual rates for assets in service as of December 31, 2017.

This study utilizes the Straight-Line method and the Average Life Group ("ALG") procedure applied on a remaining life basis for each depreciable group of assets. The calculations were based on attained ages and estimated average service life and forecasting net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2017, are amortized over the remaining life of assets.

FortisBC Energy's accounting policy has not changed since the last depreciation study was prepared. It continues to recognize the recovery of future costs of removal over the average service of the assets, and therefore includes estimated costs of removal percentages into the depreciation rate calculations costs of removal.

Concentric recommends the calculated annual depreciation accrual rates set forth in this study apply specifically to plant in service, as of December 31, 2017, as summarized by Tables 1, and 1A (pages 5-2 to 5-4). Supporting data and calculations are provided within this study.

This study results in an annual depreciation expense accrual of $190.3 million, when applied to depreciable plant balances, as of December 31, 2017. The study results are summarized at an aggregate functional group level as follows:

Functional Group	Original Cost	Annual Accrual	
Intangible Plant	$136,998,871	6.24%	$8,548,543
Manufacturing Plant	$6,061,090	1.85%	$111,838
LNG Plant	$255,220,170	3.08%	$7,853,138
Transmission Plant	$1,752,686,918	2.08%	$36,375,379
Distribution Plant	$3,362,162,148	3.66%	$122,952,934
Bio Gas	$14,952,959	3.99%	$596,177
NG for Transportation	$30,239,026	4.47%	$1,350,648
General Plant	$293,627,637	4.26%	$12,516,910
TOTAL	**$5,851,948,820**	**3.25%**	**$190,305,567**

SECTION 2

2 INTRODUCTION

2.1 Scope

This report sets forth the results of the depreciation study for assets of FortisBC Energy to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of FortisBC Energy's distribution, transmission and general plant assets as of December 31, 2017. The rates and amounts are based on the Straight-Line method of depreciation, incorporating the ALG procedure applied on a remaining life basis. This study also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to the distribution system in service as of December 31, 2017.

The service life estimates resulting from this study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2017;
- a review of FortisBC Energy's practices and outlooks as they relate to plant operation and retirement;
- review of the Company's upcoming capital and retirement projects; and
- consideration of current practice in the gas distribution industry, including knowledge of service life estimates used for other gas distribution companies.

The depreciation accrual rates presented in this study are based on generally-accepted methods and procedures for calculating depreciation.

2.2 Plan of Study

This study is presented in the following order:

SECTION 1	Study Highlights, presents a brief summary of the depreciation study and results
SECTION 2	Introduction, contains statements with respect to the plan and the basis of the study
SECTION 3	Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study
SECTION 4	Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation
SECTION 5	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1 and 1A
SECTION 6	Presents Actuarial Analysis Calculations
SECTION 7	Presents Net Salvage Calculations
SECTION 8	Presents Detailed Depreciation Calculations
SECTION 9	Estimation of Survivor Curves provides an overview of Iowa curves and the Retirement Rate Analysis

2.3 Service Life and Net salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of the Company's plans, policies and outlook, a general knowledge of the gas utility industry, and comparisons of the service life and net salvage estimates from our studies of other natural gas utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for natural gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in Tables 1 and 1A (Section 5, pages 5-2, 5-3 and 5-4) of this study. The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

2.4 Information Provided by FortisBC Energy

FortisBC Energy has provided Concentric with the required information, as of December 31, 2017, for all accounts being studied. This information has been compiled from the plant accounting records and includes the following:

- current balances by vintage year for each account (aged balances). The balances provide the amount of investment sorted by installation year currently in operation. This file is only inclusive of current plant in service and does not include any retirement information;
- detailed retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired as well as the original cost of the asset being retired; and
- detailed cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.5 Data Reconciliation

The above data was reviewed and reconciled to FortisBC Energy's control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;

- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that the cost of removal, retirement and gross salvage data over time corresponds to plant and accounting records and their analyses reflects an accurate representation of net salvage.

3 DEVELOPMENT OF DEPRECIATION PARAMETERS

3.1 Depreciation

Depreciation, as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, decay, changes in the art, changes in demand and the requirements of public authorities[1]. When considering the action of the elements, the average service life calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, wind storms, large scale flooding, fires, actions of third parties and other natural forces of nature.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.2 Depreciation Methods and Procedures

This study calculates the annual and accrued depreciation using the Straight-Line method and ALG procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. The depreciation rates determined in this study incorporate any required

[1] The National Association of Railroad and Utilities Commissioners, Uniform System of Accounts for Class A and B Electric Utilities. The Definition used by the Federal Energy Regulatory Commission for electric is essentially the same.

correction between the calculated accrued depreciation (theoretical reserve) and the actual booked accumulated depreciation reserve over the composite remaining life of each account.

3.2.1 Estimation of Survivor Curves and Net Salvage

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as Iowa type curves. The Iowa curves *"...were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life."*[2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion ("residual measure"). The residual measure is based on a least square solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the residual measure, the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely-used practice of fitting Iowa curves up to 1 percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. Concentric will however recognize the observed data points beyond the 1 percent of maximum exposures if it is determined that the additional data is a valid consideration for life recommendation.

A discussion of the general concept of survivor curves and retirement rate method is presented in Section 9.

3.2.2 Survivor Curve and Net Salvage Judgments

The service life estimates used in the depreciation and amortization calculations were based on informed professional judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the gas distribution industry, and comparisons of the service life

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[2] Robley Winfrey, *Statistical Analyses of Industrial Property Retirements*, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

estimates from our studies of other gas distribution companies. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for gas plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The following discussion, dealing with the Company's accounts by function, which comprise the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates.

ACCOUNT 443.05 – LNG PLANT - EQUIPMENT - MT. HAYES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
60,659,737	1.04%	60-R5	60-R5	-20%	-20%

The current approved life parameter for this account is an Iowa 60-R5. This account contains costs of dikes, tanks and associated equipment used for the storage of liquid natural gas and liquefied petroleum gas.

It is becoming more common for gas transmission and distribution utilities to install liquefied natural gas facilities throughout Canada. However, there is not a large peer database to draw from in order to develop a peer comparison for these assets. As these assets are new and have only been in service since 2011, there has not been enough time for a retirement rate analysis to be useful. Concentric notes that there have been no recorded retirements in this account yet, which is expected with the Iowa R5 curve. The expected retirement ratio at 10 percent of the average service life is zero percent, meaning that the proposed Iowa curve would expect no retirements of the original cost by age six for an account using an Iowa 60-R5 curve.

Given the lack of retirement history, Concentric does not recommend any change to the life or mode of this account. Concentric viewed that the comments from the operational and management personnel was a reasonable expectation for this account and that an Iowa 60-R5 is consistent with the operations and management comments.

As there have been no recorded retirements, there has not been any recorded cost of removal or gross salvage expenditures. Consequently, Concentric is not recommending a change from the approved negative 20 percent salvage rate at this time.

ACCOUNT 448.20 – LNG PLANT – PRE-TREATMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
29,241,933	0.50%	25-R3	25-R3	-10%	-10%

The current approved life parameter for this account is an Iowa 25-R3. This account contains costs incurred in the process of removing impurities from the feed gas such as water, carbon dioxide, heavy hydrocarbons and odorant to prevent process equipment from fouling or plugging by the freezing of these impurities.

It is becoming more common for gas transmission and distribution utilities to install liquefied natural gas plants throughout Canada. However, there is not a large peer database to draw from in order to develop a peer comparison for these assets. As these assets are new and have only been in service since 2011 there has not been enough time for a retirement rate analysis to be useful. Concentric notes that there have been no recorded retirements in this account yet, which is expected with the Iowa R3 curve. The expected retirement ratio at 24 percent of the average service life is 0.9941 percent, meaning that the proposed Iowa curve would expect less than one percent of the total the original cost to be retired by age six for an account using an Iowa 25-R3 curve.

Given the lack of retirement history, Concentric does not recommend any change to the life or mode of this account. Concentric viewed that the comments from the Company's operational and management personnel was a reasonable expectation for this account and that an Iowa 25-R3 is consistent with the operations and management comments.

As there have been no recorded retirements, there has not been any recorded cost of removal or gross salvage expenditures. Consequently, Concentric is not recommending a change from the approved negative 10 percent salvage rate at this time.

ACCOUNT 448.30 – LNG PLANT – LIQUIFICATION EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
28,883,117	0.49%	40-R3	40-R3	-20%	-20%

The current approved life parameter for this account is an Iowa 40-R3. This account contains costs incurred in the process of cooling and condensing the clean gas stream to its liquid state for storage.

It is becoming more common for gas transmission and distribution utilities to install liquefied natural gas plants throughout Canada. However, there is not a large peer database to draw from in order to develop a peer comparison for these assets. As these assets are new and have only been in service since 2011, there has not been enough retirement experience for a retirement rate analysis to be useful. Concentric notes that there have been no recorded retirements in this account yet, which is expected with the Iowa R3 curve. The expected retirement ratio at 15 percent of the average service life is 0.4251 percent, meaning that the proposed Iowa curve would expect less than half of one percent of the total original cost to be retired by age six for an account using an Iowa 40-R3 curve.

Given the lack of retirement history, Concentric does not recommend any change to the life or mode of this account. Concentric viewed that the comments from the Company's operational and management personnel was a reasonable expectation for this account and that an Iowa 40-R3 is consistent with the operations and management comments.

As there have been no recorded retirements, there has not been any recorded cost of removal or gross salvage expenditures. Consequently, Concentric is not recommending a change from the approved negative 20 percent salvage rate at this time.

ACCOUNT 449.00 – LNG PLANT – OTHER EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
25,739,908	0.44%	27-R3	27-R3	-10%	-10%

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1970 through 2017, and the retirement experience over the period of 1985 through 2017. Over this 48-year period, this account experienced $3.0 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on page 6-22 of this report.

Interviews with FortisBC Energy operations and management staff have indicated that the statistically indicated average service life of 33 years for the equipment in this account is not consistent with their expectations. Concentric viewed that the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, maintaining the currently approved Iowa 27-R3 is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

The net salvage study indicates that the currently approved negative 10 percent net salvage is still appropriate. There has only been one year since 2009 with retirements recorded for this account and there has not been any net salvage recorded in the three years since the last depreciation study. Consequently, Concentric recommends maintaining the currently approved negative 10 percent net salvage estimate.

Based on historical indications and the comments from the operations and management personnel, Concentric views that negative 10 percent best represents the net salvage expectation for the assets in the LNG Plant - Other Equipment account.

ACCOUNT 462.00 – TRANSMISSION PLANT – COMPRESSOR STRUCTURES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
31,562,024	0.54%	30-R4	30-S4	-3%	-3%

This account consists of the material and installation cost associated with structures for compressor sites. The retirement rate analysis prepared in this study reviewed the plant installed over the period 1965 through 2017, and the retirement experience over the period of 1974 through 2017. Over this 53-year period, this account experienced $842,709 of retirements which indicates a high-moded Iowa curve.

This study results in a minor change in the Iowa curve from 30-R4 to 30-S4. This change reflects that there has not been significant retirement experienced since the last depreciation study.

There is a total of eight compressor sites on the mainland and three on Vancouver Island, each with multiple buildings and units on site. The buildings are generally large, aluminum sided or galvanized steel with steel beams inside, on concrete pads. The buildings are large, very well built and there is very little interim retirement expected for the buildings themselves. The cranes and other large equipment that are part of these sites are accounted for in the buildings account. Most of this equipment is still early in its life cycle and there have been very few retirements.

The previously approved estimate for this account was the Iowa 30-R4 with a residual measure of 0.2726. Based on the retirement rate analysis and the expectations of operational staff, Concentric recommends the modification to the Iowa 30-S4, with a better residual measure of 0.2130, to be appropriate for this account.

The net salvage study indicates that the currently approved negative three percent net salvage is still appropriate. There has only been three years with retirements recorded for this account and there has not been any net salvage recorded in the three years since the last depreciation study. Consequently, Concentric recommends maintaining the currently approved negative 3 percent net salvage estimate.

ACCOUNT 465.00 – TRANSMISSION PLANT – TRANSMISSION PIPELINES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
1,371,509,954	23.44%	65-R3	65-R4	-20%	-20%

FortisBC Energy gas transmission pipelines account consists of completely cathodic protected steel pipeline mains. The mains range in size from ¾ inch up to 42 inch in diameter and all operate above 500 psi as per the CSA Group designation. There has been ongoing maintenance to pig all pipelines every seven years in order to ensure that pipes are operating under approved stress levels. Currently hundreds of meters of pipe are found to need replacement every year and are replaced as needed. These pipes generally exceed 61 years of age at the time of replacement.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1957 through 2017, and the retirement experience over the period of 1962 through 2017. Over this 60-year period, this account has experienced almost $21.0 million of retirements over a narrowly dispersed range of ages, as summarized on the observed life table as provided on page 6-35 and 6-36 of this report. The original survivor curve, as plotted on page 6-37, shows a minimal level of retirement activity through the account's early life. However, at approximately age 30, the account begins to exhibit many larger retirement ratios through the remainder of the life of the account. The previous estimate for this account was the Iowa 65-R3 with a residual measure of 0.3896. Comments from the operations and management group suggested that the life of this account is expected to remain consistent going forward.

Concentric reviewed a selection of peer Canadian natural gas transmission companies. Average service life estimates among these peers ranged from 60 years through 65 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R4, with a residual measure of 0.1980, is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

This study recommends maintaining the net salvage percentage at negative 20 percent. Inclusion of data from the last three years shows a very strong trend to higher negative net salvage rates. The last three three-year rolling bands are all more negative than negative 40 percent. The historical net salvage rate is negative 28 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 25 percent at this time, however given the concept of gradualism Concentric is recommending maintaining the net salvage at negative 20 percent. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

ACCOUNT 465.11- TRANSMISSION PLANT – INTERMEDIATE PIPE - WHISTLER

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
42,295,869	0.72%	65-R3	65-R3	-20%	-20%

This is a new account containing additions installed since 2008. There have been no recorded retirements at the time of this study. As these assets are new and have only been in service since 2008, there has not been enough time for a retirement rate analysis to be useful. There have been no recorded retirements in this account yet, which is expected with the Iowa R3 curve. The expected retirement ratio at 15 percent of the average service life is 0.4251 percent, meaning that the proposed Iowa curve would expect less than half of one percent of the total original cost to be retired by age ten for an account using an Iowa 65-R3 curve.

Given the lack of retirement history, Concentric does not recommend any change to the life or mode of this account. Concentric viewed that the comments from the operational and management personnel was a reasonable expectation for this account and that an Iowa 65-R3 is consistent with the operations and management comments.

Given the lack of retirement history, Concentric does not recommend any change to the net salvage estimate at this time. Comments from operational and management personnel indicate that negative 20 percent is still an appropriate estimate.

ACCOUNT 466.00 TRANSMISSION PLANT – COMPRESSOR EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
190,510,140	3.26%	35-R4	37-R4	-2%	-3%

This account contains electric and gas turbine compressor equipment. These units are maintained at approximately every 5,000 hours with major overhauls being accounted for in Account 466.10.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1965 through 2017, and the retirement experience over the period of 1973 through 2017. Over this 52-year period, this account has experienced almost $5.8 million of retirements over a narrowly dispersed range of ages, as summarized on the observed life table as provided on pages 6-40 and 6-41 of this report. The retirement experience for the 2014 through 2017 period represents $1.3 million of the total $5.8 million. The average age of retirement over this 2014 through 2017 period was 24.2 years, as compared to an average age of retirement transactions for all years prior to 2014 of 16.9 years. This increase in average age of retirement transactions over the most recent three years has resulted in the indication of an increased average service life indication.

The original survivor curve, as plotted on page 6-42, shows a minimal level of retirement activity through the account's early life. However, at approximately age 20, the account begins to exhibit higher retirement ratios through the remainder of the life of the account. The previous estimate for this account was the Iowa 35-R4 with a residual measure of 1.1055 which does not provide a reasonable fit to the historical retirement patterns. Comments from the operations and management group suggested that the life of this account is expected to lengthen going forward.

Concentric reviewed a selection of peer Canadian natural gas transmission companies. Average service life estimates among these peers is 35 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 37-R4 with a residual measure of 0.7927 is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

This study recommends making a small change to the net salvage rate, from negative two percent to negative three percent. Inclusion of data from the last three years shows a trend to higher negative net salvage rates. The last two three-year rolling bands are both more negative than negative five percent. The historical net salvage rate is negative three percent. Concentric views that it would be reasonable to change the net salvage rate to negative three percent at this time.

ACCOUNT 467.10 TRANSMISSION PLANT – MEASURING AND REGULATING EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
62,016,326	1.06%	36-S0.5	37-R1.5	-7%	-5%

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1959 through 2017, and the retirement experience over the period of 1968 through 2017. Over this 58-year period, this account has experienced $7.4 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-45 and 6-46 of this report. The original survivor curve, as plotted on page 6-47, shows a steady rate of retirement throughout the life of this account indicating the need for a low-moded curve. The previous estimate for this account was the Iowa 36-S0.5 with a residual measure through the life of this account of 0.7128. Comments from the operations and management group suggested that the life of this account is expected to lengthen going forward.

Concentric reviewed a selection of peer Canadian natural gas transmission companies. Average service life estimates among these peers ranged from 35 years through 45 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 37-R1.5 with a residual measure of 0.5206 is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

Based on the historical data provided to Concentric and analyzed in a net salvage study, a net salvage percentage of negative five percent is recommended for this asset account - a decrease from the prior study of negative seven percentage. The recommendation is based upon discussions with FortisBC Energy operations and management staff along with an in-depth net salvage study. There has not been any net salvage recorded in the last two years; consequently, the historical net salvage rate has fallen from negative seven percent to negative six percent. Operations and management staff believe that the rate will continue to fall and that a further reduction to negative five percent is required at this time.

Based on historical indications and the comments from operations and management personnel, Concentric views that negative five percent best represents the net salvage expectation for the assets in the Measuring and Regulating Equipment account.

ACCOUNT 473.00 – DISTRIBUTION PLANT - SERVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
1,160,659,173	19.84%	45-R1	47-R2	-60%	-70%

This account contains predominantly ¾ inch steel and plastic service lines which are very rarely replaced. There are minimal pro-active replacements made when the associated main is upgraded or replaced. There has been an industry wide trend to more gas fired appliances within customer homes, however the lives of services are not dependent on the size of the service. FortisBC Energy did not begin to install plastic services until 1981, meaning that the life of services should be on the longer end of peer utilities as there is no early plastic replacement program required.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1900 through 2017, and the retirement experience over the period of 1963 through 2017. Over this 118-year period, this account has experienced almost $105.0 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-60, 6-61 and 6-62 of this report. The retirement experience for the 2014 through 2017 period represents $11.4 million of the total $105.0 million. The average age of retirement over this 2014 through 2017 period was 20.2 years, as compared to an average age of retirement transactions for all years prior to 2014 of 12.3 years. This increase in average age of retirement transactions over the most recent three years has resulted in the indication of an increased average service life indication.

The original survivor curve, as plotted on page 6-63, shows a steady rate of retirement throughout the life of this account, indicating the need for a low-moded curve. The previous estimate for this account was the Iowa 45-R1 with a residual measure of 0.9642. Comments from the operations and management group suggested that the life of this account is expected to lengthen going forward.

Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 40 through 62 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 47-R2, with a residual measure of 0.1547, is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

This study recommends making a change to the net salvage rate, from negative 60 percent to negative 70 percent. Inclusion of data from the last three years shows a trend to higher negative net salvage rates. The last eight three-year rolling bands are both more negative than negative 100 percent, as are the last seven five-year rolling bands. The historical net salvage rate is negative 119 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 100 percent at this time, however given the concept of gradualism Concentric is recommending moving the net salvage to a negative 70 percent. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

Based on historical indications and the comments from operations and management personnel, Concentric views that negative 70 percent best represents the net salvage expectation for the assets in this Distribution Plant - Services account.

ACCOUNT 474.00 – DISTRIBUTION PLANT – METER/REGULATOR INSTALLATIONS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
188,387,340	3.22%	20-S0	20-S0 & 23-SQ	-20%	-20%

Approximately 87 percent of this account relates to the installation costs of older gas meters which are due to be completely retired in 2035. The remaining 13 percent is related to station regulator assets. The investment relating to installation of meters costs follow an amortization accounting method and are expected to be completely retired in 2035. The remaining 13 percent of this account, relating to installation of station regulators, follow traditional regulatory retirement accounting practices and are expected to be in service until the end-of-life of the asset. At this time, Concentric recommends that the annual depreciation accrual should be weighted in accordance with the retirement practices for the two groups of assets in this account. With this approach, the resultant depreciation accrual rate will recognize the amortization accounting treatment related to meter installations and will also be applicable for the station regulators which will be retired in accordance with traditional regulatory accounting practices. There are detailed investment records for both groups of assets, therefore, it is possible to calculate the depreciation accrual for both groups independently and then sum the depreciation accruals amounts to determine an overall weighted depreciation rate applicable to the account as a whole.

As the majority of the investment in this account relates to amortization assets, there was not a retirement rate analysis prepared. Concentric viewed that the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 20-S0 is recommended for the station assets in this account and the 23-SQ is recommended for the meter installation assets based on the indications from management and operations, and on the professional judgement of Concentric.

This study recommends maintaining the net salvage percentage at negative 20 percent. Inclusion of data from the last three years shows a very strong trend to higher negative net salvage rates. The last six three-year rolling bands are all more negative than negative 40 percent. The historical net salvage rate is negative 38 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 30 percent at this time, however given the concept of gradualism, Concentric is recommending maintaining the net salvage at negative 20 percent. Close monitoring of this account will be necessary in future depreciation studies to ensure that the net salvage rate is changed as necessary.

ACCOUNT 475.00 – DISTRIBUTION PLANT – SYSTEMS - MAINS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
1,427,597,191	24.40%	64-R2.5	65-R2.5	-25%	-25%

This account contains steel and plastic distribution mains. The company has been undertaking replacement program since 2013 which is still on-going. Currently, approximately seven kilometers per year are replaced on a proactive basis. These replacements are targeted based on age and risk of future problems. Almost all of the pipe being replaced is older vintage. This program is expected to be ongoing with no foreseeable plans to increase or decrease the retirements. FortisBC Energy did not begin to install plastic mains until 1981, meaning that the life of mains should be on the longer end of peer utilities as there is no early plastic replacement program required.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1924 through 2017, and the retirement experience over the period of 1963 through 2017. Over this 93-year period, this account has experienced $50.0 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-66 and 6-67 of this report. The retirement experience for the 2014 through 2017 period represents $4.1 million of the total $50.0 million. The average age of retirement over this 2014 through 2017 period was 20.3 years, as compared to an average age of retirement transactions for all years prior to 2014 of 13.6 years. This increase in average age of retirement transactions over the most recent three years has resulted in the indication of an increased service life indication.

The original survivor curve, as plotted on page 6-68, shows a steady rate of retirement throughout the early life of this account, with rapidly increasing retirements beginning at age 66 indicating the need for a mid-moded curve. The previous estimate for this account was the Iowa 64-R2.5 with a residual measure of 0.0810. Comments from the operations and management group suggested that the life of this account is expected to remain consistent going forward.

Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 61 through 68 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 65-R2.5, with a residual measure of 0.1728, is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

This study recommends maintaining the currently approved negative 25 percent net salvage rate. Inclusion of data from the last three years shows a trend to higher negative net salvage rates. The last seven three-year rolling bands are both more negative than negative 30 percent, as are the last six five-year rolling bands. The historical net salvage rate is negative 30 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 30 percent at this time, however given the concept of gradualism, Concentric is recommending maintaining the net salvage at negative 25 percent.

Based on historical indications and the comments from operations and management personnel, Concentric views that negative 25 percent best represents the net salvage expectation for the assets in the Distribution Plant – Systems – Mains account.

ACCOUNT 477.10 – DISTRIBUTION PLANT – MEASURING AND REGULATING

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
143,051,691	2.44%	30-R2	33-R2	-10%	-12%

This account contains a mix of measuring and regulating equipment including regulators, valves, line heaters, filters and process flow piping. This equipment is generally very easy to replace and size up or down as needed. Consequently, measuring and regulating stations are often built with the intention of being sized properly for the current need while being able to expand later; this means that there are many smaller value retirements to right size the equipment but far fewer large retirements due to stations no longer suiting the intended need.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1957 through 2017, and the retirement experience over the period of 1959 through 2017. Over this 60-year period, this account has experienced $17.8 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-73 and 6-74 of this report. The original survivor curve, as plotted on page 6-75, shows a steady rate of retirement throughout the early life of this account indicating the need for a low-moded curve. The previous estimate for this account was the Iowa 30-R2 with a residual measure of 0.4202, however, this fit is too short after age 23. Comments from the operations and management group suggested that the life of this account is expected to continue to lengthen going forward.

Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 33 through 50 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 33-R2 with a residual measure of 0.0535 is recommended for this account based on the fit to the historic data, the indications from management and operations, and on the professional judgement of Concentric.

This study recommends making a change to the net salvage rate from negative 10 percent to negative 12 percent. Inclusion of data from the last three years shows a trend to higher negative net salvage rates. The last three three-year rolling bands are both more negative than negative 10 percent, as are the last two five-year rolling bands. The historical net salvage rate is negative 12 percent. Concentric views that it would be reasonable to change the net salvage rate to negative 12 percent at this time.

Based on historical indications and the comments from operations and management personnel, Concentric views that negative 12 percent best represents the net salvage expectation for the assets in this Distribution Plant – Measuring and Regulating.

ACCOUNT 478.10 – DISTRIBUTION PLANT - METERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
256,174,679	4.38%	18-R2.5	18-R4	0	0

This account contains mechanical gas meters, 90 percent of which are small residential units. FortisBC Energy is currently not using AMR/AMI technology for this account. Consequently, FortisBC Energy would be expected to have a life on the longer end of the peer comparison as many Canadian utilities have implemented AMR/AMI technology. Measurement Canada standard S-S-06 is the largest influence on the average service life of the units in this account. This standard dictates that each vintage has significant testing after 10 years, then again after eight years and a following six years. Meters are expected to pass the first seal period, however, it is expected that there will be significant failure at the second round of testing. FEI is currently investigating the feasibility of an Advanced Metering initiative which may impact the remaining life of its meter assets. The recommended depreciation rates in this study do not contemplate the impact of the Advanced Metering initiative and will have to be reviewed should the Company proceed with the initiative.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1963 through 2017 and the retirement experience over the period of 1963 through 2017. Over this 54-year period this account has experienced $99.0 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-81 and 6-82 of this report. The original survivor curve, as plotted on page 6-83, shows a steady rate of retirement throughout the early life of this account with a significant increase in retirements occurring between approximately age five and age 20 indicating the need for a mid-moded curve. The previous estimate for this account was the Iowa 18-R2.5, which does not provide a good fit to the historical retirement patterns in the early life with a residual measure of 1.0284. However, comments from the operations and management groups indicate that the historical data in this account is not expected to be indicative of future activity. It is expected that the life of this account will continue to shorten due to the Measurement Canada standards and the technological changes expected in the future.

Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 15 through 30 years. Concentric viewed that the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 18-R4, with a residual measure of 1.2579, is recommended for this account based on the indications from management and operations, and on the professional judgement of Concentric.

This study recommends maintaining no net salvage estimate. Inclusion of data from the last three years shows a trend to higher positive net salvage rates. The last ten three-year rolling bands are both more positive than one percent, as are the last ten five-year rolling bands. The historical net salvage rate is one percent. Peer utilities have estimates ranging from zero to five percent. Concentric views that it would be reasonable to maintain no net salvage estimate at this time, however, this account requires careful monitoring in the future.

ACCOUNT 482.20 – STRUCTURES - MASONRY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
114,701,266	1.96%	50-R2.5	60-R2	-10%	-4%

This account contains the largest buildings in the FortisBC Energy portfolio, including the head office located in Surrey and purchases in Burnaby. The Surrey and Burnaby buildings were purchased in 2005 and have been built with a utilitarian esthetic design to ensure that there are minimal upgrades needed later. One of the largest forces of retirements are changes to the economic and business needs. As the business grows and changes, different buildings are needed which forces retirement of older buildings. There have also been substantial changes to building standards, including regulations regarding access for people with disabilities and building code updates which means that the oldest buildings can no longer be used effectively.

The retirement rate analysis prepared in this study reviewed the plant installed over the period 1960 through 2017, and the retirement experience over the period of 1978 through 2017. Over this 58-year period, this account has experienced $2.6 million of retirements over a widely dispersed range of ages, as summarized on the observed life table as provided on pages 6-90 and 6-91 of this report. The original survivor curve, as plotted on page 6-92, shows a steady rate of retirement throughout the early life of this account indicating the need for a mid-moded curve. The previous estimate for this account was the Iowa 50-R2.5 with a residual measure of 0.5103. Comments from the operations and management groups indicate that the historical data in this account is not expected to be indicative of future activity. It is expected that the life of this account will continue to lengthen in the future.

Concentric reviewed a selection of peer Canadian natural gas distribution companies. Average service life estimates among these peers ranged from 30 through 75 years. Concentric viewed that the observed life indication combined with the comments from the operational and management personnel was the most reasonable expectation for the equipment in this account. As such, the Iowa 60-R2, with a residual measure of 0.0577, is recommended for this account based on the indications from management and operations, and on the professional judgement of Concentric.

This study recommends making a change to the net salvage rate from negative 10 percent to negative four percent. Inclusion of data from the last three years shows a trend to lower negative net salvage rates. The historical net salvage rate is negative 11 percent. Concentric views that it would be reasonable to change the net salvage rate to negative four percent at this time.

Based on historical indications and the comments from operations and management personnel, Concentric views that negative four percent best represents the net salvage expectation for the assets in the General Plant – Structure – Masonry account.

3.3 Other Accounts

The above analysis provides the consideration relating to over 87 percent of the depreciable plant. Many of the accounts related to the remaining 13 percent of the depreciable plant studied, as of December 31, 2017, are subjected to amortization accounting. This is proposed for a number of accounts that represent numerous units of property but very small portions of depreciable gas plant in service.

3.4 Impact of Recent Government Policies Related to Carbon Reduction Initiatives

Concentric has been advised by FortisBC management of recent policy statements of the BC government pertaining to enhanced actions to address climate change and greenhouse gas emission reductions. FortisBC views that these statements could have the potential to affect FortisBC's gas distribution business significantly within the next ten to twenty years, depending on how the policies are implemented. Concentric has reviewed the Government of British Columbia's recently released CleanBC Plan, as well as other related documents, and notes the following based on its review of these documents.

The CleanBC plan, released on December 5th, 2018 provides a plan related to achieving greenhouse gas reduction targets. This action plan outlines British Columbia's goal to *"increase our use of cleaner energy, especially renewable hydro-electricity, in our lives and in key sectors of our economy – shifting away from our reliance on fossil fuels for transportation, industry, and housing."* The CleanBC plan is aimed at achieving the legislative changes introduced on May 7, 2018 to update the Province's greenhouse gas reduction targets. The updated legislation sets new targets of:

- a 40% reduction in carbon emissions from 2007 levels by 2030;
- a 60% reduction from 2007 levels by 2040; while
- the previously-established target of an 80% reduction in emissions by 2050 remains.

The CleanBC plan anticipates meeting the above targets through a strategy of reducing Green House Gas (GHG) emissions by shifting away from fossil fuels and towards clean and renewable energy. The plan specifically indicates that:

> *"To meet our goals, we must increase our use of cleaner energy, especially electricity, in our lives and in key sectors of our economy – shifting away from our reliance on fossil fuels for transportation, industry, and housing. Together, we can make these sectors more efficient, so we use less energy and waste less, and make sure the energy we do use is the cleanest possible. People will benefit with more comfortable buildings, cleaner air, and more transportation options".*

If there is success in the achievement of the proposed CleanBC Plan objectives, there may be a significant impact on how the FortisBC system assets are utilized, with potential increasing impacts through the next ten years and until 2050. The action plan anticipates that reducing natural gas use, which currently provides over half of British Columbia's residential heating, will require mass adoption of green technologies in buildings across the province. The plan outlines changes to building codes and standards that will make new buildings more efficient in the future, in addition to improving the efficiency of existing buildings through providing targeted incentives. In addition to the CleanBC plan, the province of British Columbia introduced the EfficiencyBC program in September 2018 to provide a number of matching rebates to, for example, lower the costs of replacing natural gas furnaces with heat pumps.

Although some of the CleanBC initiatives, such as the plan to require 15% renewable content in the natural gas stream by 2030, represent opportunities for continued use of the natural gas system, the overall trend toward reduced natural gas use may cause the future growth and retirement programs of the FortisBC system to be significantly different than the retirement patterns witnessed in the past. While future retirements that are caused by normal forces of retirement, such as wear and tear and changes in technology of the assets, will continue, it is important to assess whether the utilization of groups of assets is changing due to the implementation of action plans or programs such as CleanBC and EfficiencyBC. Consistent with the change in the utilization of the assets, it is possible that larger scale asset retirements may be required in the periods between now and 2050.

Common depreciation practice is to deal with the anticipated large-scale retirements through the increased componentization of accounts in order to provide a shorter remaining life on the investment that will be most suspectable to the impacts of the carbon reduction initiatives. Additionally, the introduction of a Life Span date within the depreciation rate calculations may be required for the accounts most impacted. However, at this time the future impacts of the CleanBC plan have not been sufficiently studied, nor have specific programs been developed in enough detail or had sufficient time to provide indications of changes in the utilization of assets. The introduction of a Life Span date will cause a significant increase to the depreciation rates. Consequently, Concentric views that additional study of the changes is required before the introduction of a Life

Span date for the FortisBC system. However, Concentric notes that future depreciation studies of the FortisBC system may require the introduction of a Life Span into the depreciation rate calculations.

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because (normally) all of the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group procedure (Also known as the Average Service Life procedure), the rate of annual depreciation is based on the average service life of the group - this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

In the determination of the depreciation rates in this study, the use of the Average Life Group procedure has been continued. While the Equal Life Group procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Average Life Group procedure was used in order to conform to past Company practices and approvals by the BCUC.

4.2 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for a number of accounts. The accounts and their amortization periods are as follows:

Account	Title	Amortization Period, Years	Net Salvage Percentage
402.01	Computer Software Applications – 8 Years	8	-
402.02	Computer Software Applications – 5 Years	5	-
474.02	Distribution Plant – New Meter Installations	22	-
483.10	Computer Hardware	4	-
483.20	Computer Software (12.5%)	8	-
483.25	RNG Computer Software (20%)	5	-
483.30	Office Equipment	15	-
483.40	Furniture	20	-
486.00	Small Tools/Equipment	20	-
487.20	NGV Cylinders	15	-
488.10	Telephone Equipment	15	-
488.20	Radio Equipment	15	-

For calculating annual amortization amounts, as of December 31, 2017, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. Any amount of book reserve in vintages older than the amortization period has been deducted from both the original cost as well as from accumulated depreciation. This approach assumes that the original costs of vintages, older than the chosen amortization period, will have been retired along with their accumulated depreciation.

The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age, to its amortization period. An annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

Amortization accounting is widespread across various regulated utilities including electrical and gas utilities.

SECTION 5

5 RESULTS OF STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the Average Life Group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other gas distribution utilities. The results of the statistical analysis of service life are presented in Section 6, beginning on page 6-2 of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2017, are presented in account sequence starting on page 8-2 of the supporting documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation, and the calculated annual accrual.

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SCHEDULE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
INTANGIBLE PLANT									
401.01	Franchises and Consents	40-SQ	-	297,252	212,425	84,827	3,208	1.08	19.90
402.01	Computer Software Application - 8 Years	8-SQ	-	114,130,181	65,227,079	48,484,528	6,060,566	12.50 *	3.44
402.02	Computer Software Application - 5 Years	5-SQ	-	20,602,390	8,282,646	12,319,744	2,463,949	20.00 *	3.05
402.03	Intangible Plant	40-SQ	-	1,906,591	1,073,775	832,816	20,820	2.50 *	20.99
402.11	Plant Acquisitions and Adjustments	40-SQ	-	62,457	62,457	-	-	-	32.00
TOTAL INTANGIBLE PLANT				**136,998,871**	**74,858,382**	**61,721,916**	**8,548,543**	**6.24**	
MANUFACTURING PLANT									
432.00	Structures	40-SQ	-	992,394	309,160	683,234	17,081	2.50 *	26.09
433.00	Equipment	20-SQ	-	516,348	236,230	280,118	14,006	5.00 *	11.68
434.00	Holders	40-SQ	-	2,954,888	584,808	2,370,080	59,252	2.50 *	32.39
436.00	Compressor Equipment	25-SQ	-	366,583	126,866	239,717	9,589	4.00 *	17.52
437.00	Measuring and Regulating Equipment	20-SQ	-	1,230,878	992,664	238,214	11,911	5.00 *	12.17
TOTAL MANUFACTURING PLANT				**6,061,090**	**2,249,728**	**3,811,362**	**111,838**	**1.85**	
LNG PLANT									
442.00	Structures	25-L2	-	5,209,412	3,670,131	1,539,281	114,594	2.20	12.29
442.01	Structures - Mt. Hayes	25-L2	-	19,038,721	4,618,064	14,420,657	732,118	3.85	19.68
443.00	Equipment	40-S4	-	16,713,755	12,310,410	4,403,345	205,728	1.23	17.68
443.05	Equipment - Mt. Hayes	60-R5	-	60,659,737	6,597,849	54,061,888	1,000,194	1.65	54.05
448.10	Piping	40-R3	-	12,433,032	1,887,707	10,545,325	304,762	2.45	34.59
448.20	Pre-Treatment	25-R3	-	29,241,933	7,555,227	21,686,706	1,124,000	3.84	19.29
448.30	Liquefaction Equipment	40-R3	-	28,883,117	4,718,462	24,164,655	706,922	2.45	34.18
448.40	Send Out Equipment	40-R2	-	23,555,076	3,782,268	19,772,808	568,403	2.41	34.78
448.50	Substation and Electrical	40-R2	-	21,790,943	3,553,200	18,237,743	525,496	2.41	34.70
448.60	Control Room	15-R3	-	6,354,097	2,613,477	3,740,620	386,741	6.09	9.65
449.00	Other Equipment	27-R3	-	25,739,908	16,141,911	9,597,997	713,617	2.77	11.87
449.01	Other Equipment - Mt. Hayes	33-R3	-	5,600,437	323,087	5,277,350	172,643	3.08	30.57
TOTAL LNG PLANT				**255,220,170**	**67,771,795**	**187,448,375**	**6,555,217**	**2.57**	
TRANSMISSION PLANT									
462.00	Compressor Structures	30-S4	-	31,562,024	16,731,361	14,830,663	1,048,868	3.32	14.12
463.00	Measuring and Regulating Structures	38-S2	-	15,076,202	7,107,561	7,968,640	321,751	2.13	23.63
464.00	Other Structures	30-R4	-	6,768,180	2,896,457	3,871,723	244,782	3.62	16.04
465.00	Transmission Pipeline	65-R4	-	1,371,509,954	395,481,214	976,028,740	20,069,779	1.46	48.13
465.11	Intermediate Pipe - Whistler	65-R3	-	42,295,869	5,134,387	37,161,481	649,610	1.54	57.21
465.30	Mains - Mt. Hayes	65-SQ	-	6,307,725	693,485	5,614,240	86,373	1.54 *	59.01
466.00	Compressor Equipment	37-R4	-	190,510,140	88,143,732	102,366,407	4,609,829	2.42	21.57
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5	-	5,340,973	1,313,881	4,027,093	125,215	2.34	32.16
467.10	Measuring and Regulating Equipment	37-R1.5	-	62,016,326	25,117,840	36,898,487	1,313,080	2.12	26.61
467.20	Telemetry Equipment	10-L1.5	-	17,220,938	8,190,973	9,029,965	1,545,043	8.97	5.56
467.31	Measuring and Regulating Equipment - Whistler	37-R1.5	-	313,344	96,667	216,677	7,081	2.26	30.60
468.00	Communications Equipment	19-R3	-	3,765,245	4,779,395	- 1,014,151	-	-	5.56
TOTAL TRANSMISSION PLANT				**1,752,686,918**	**555,686,953**	**1,196,999,965**	**30,021,411**	**1.71**	

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DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Account	Account Description (1)	Survivor Curve (2)	Net Salvage Percent (3)	Original Cost as of Dec. 31, 2017 (4)	Book Depreciation Reserve (5)	Future Accruals (6)	Calculated Annual Accural Amount (7)	Calculated Annual Accural Rate (8)	Composite Remaining Life (9)
DISTRIBUTION PLANT									
472.00	Structures	38-R1.5	-	25,234,840	9,193,108	16,041,731	541,556	2.15	28.49
473.00	Services	47-R2	-	1,160,659,173	291,133,465	869,525,709	25,328,595	2.18	34.49
474.00	Meter/Regulator Installations	20-S0/23-SQ	-	188,387,340	82,496,856	105,890,484	14,031,510	7.45	**
474.02	New Meter Installations	22-SQ	-	132,111,279	16,651,984	115,459,295	5,248,150	4.55 *	19.46
475.00	Systems - Mains	65-R2.5	-	1,427,597,191	476,829,560	950,767,631	19,294,827	1.35	48.47
476.00	NGV Fuel Equipment	7-L0	-	613,588	2,149,456	- 1,535,868	-	-	4.43
477.10	Measuring and Regulating	33-R2	-	143,051,691	51,810,876	91,240,815	3,592,458	2.51	23.95
477.20	Telemetry	20-R3	-	14,930,538	6,075,041	8,855,497	535,339	3.59	13.34
478.10	Meters	18-R4	-	256,174,679	133,905,431	122,269,248	15,513,812	6.06	8.20
478.20	Instruments	35-R5	-	13,401,830	6,024,709	7,377,121	390,904	2.92	19.01
TOTAL DISTRIBUTION PLANT				**3,362,162,148**	**1,076,270,486**	**2,285,891,662**	**84,477,151**	**2.51**	
BIO GAS									
418.10	Purification Overhauls	20-SQ	-	20,423	3,735	16,688	834	5.00 *	17.00
418.20	Purification Upgrader	20-SQ	-	9,794,870	1,381,044	8,413,827	420,691	5.00 *	17.36
472.20	Structures and Improvements	36-R1.5	-	654,898	71,844	583,053	17,594	2.69	33.11
474.10	Meters/Regulator Installations	19-S0	-	226,054	28,936	197,117	12,035	5.32	16.38
475.10	Mains - Municipal Land	65-R2.5	-	1,655,815	68,413	1,587,402	25,768	1.56	61.61
477.40	Measuring and Regulating	30-R2	-	2,565,623	289,121	2,276,502	82,490	3.22	27.55
478.30	Meters	18-R2.5	-	35,277	8,734	26,543	1,724	4.89	15.18
TOTAL BIO GAS				**14,952,959**	**1,851,827**	**13,101,132**	**561,137**	**3.75**	
NG FOR TRANSPORTATION									
476.10	CNG Disp Equipment	20-SQ	-	12,897,495	1,832,791	11,064,704	553,235	5.00 *	17.44
476.20	LNG Disp Equipment	20-SQ	-	11,683,174	1,660,759	10,022,415	501,121	5.00 *	17.45
476.30	CNG Foundation	20-SQ	-	2,365,123	280,719	2,084,404	104,220	5.00 *	17.75
476.40	LNG Foundation	20-SQ	-	1,311,362	230,901	1,080,461	54,023	5.00 *	16.86
476.50	LNG Pumps	10-SQ	-	1,494,110	319,159	1,174,951	117,495	10.00 *	7.92
476.60	CNG Dehydrator	20-SQ	-	487,763	76,697	411,066	20,553	5.00 *	16.99
TOTAL NG FOR TRANSPORTATION				**30,239,026**	**4,401,026**	**25,838,000**	**1,350,648**	**4.47**	
GENERAL PLANT									
482.10	Stuctures (Frame)	25-R1.5	-	23,263,706	9,238,192	14,025,514	738,194	3.17	17.46
482.20	Structures (Masonry)	60-R2	-	114,701,266	27,102,987	87,598,278	1,748,208	1.52	49.75
483.10	Computer Hardware	4-SQ	-	36,928,213	16,894,852	20,033,360	5,008,340	25.00 *	1.78
483.20	Computer Software (12.5%)	8-SQ	-	7,197,065	3,274,486	3,922,579	490,322	12.50 *	4.57
483.25	RNG Computer Software (20%)	5-SQ	-	138,461	27,692	110,769	22,154	20.00 *	4.00
483.30	Office Equipment	15-SQ	-	3,377,105	1,713,206	1,663,899	110,927	6.67 *	6.88
483.40	Furniture	20-SQ	-	17,805,850	9,276,667	8,529,183	426,459	5.00 *	9.57
484.00	Vehicles	7-L1	-	20,521,572	7,712,662	12,808,910	2,272,148	11.07	5.16
485.10	Heavy Work Equipment	13-L0.5	-	905,623	485,649	419,974	46,558	5.14	8.16
485.20	Heavy Mobile Equipment	9-L1.5	-	5,384,508	2,856,060	2,528,449	327,909	6.09	6.23
486.00	Small Tools/Equipment	20-SQ	-	47,038,954	21,117,862	25,921,092	1,296,055	5.00 *	11.23
487.20	NGV Cylinders	15-SQ	-	12,336	8,375	3,961	264	6.67 *	4.25
488.10	Telephone Equipment	15-SQ	-	3,384,005	2,395,825	988,180	65,879	6.67 *	3.91
488.20	Radio Equipment	15-SQ	-	12,968,973	3,194,066	9,774,907	651,660	6.67 *	11.51
TOTAL GENERAL PLANT				**293,627,637**	**105,298,580**	**188,329,057**	**13,205,078**	**4.50**	
TOTAL DEPRECIABLE PLANT				**5,851,948,820**	**1,888,388,776**	**3,963,141,470**	**144,831,023**	**2.47**	

FortisBC Energy Inc.

SCHEDULE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
PLANT NOT STUDIED									
175.00	Unamortized Conversion/Expense				837,802				
178.00	Organizational Costs				428,218				
430.00	Manufacturing Plant - Land				20				
440.00	LNG Gas - Land				1,125				
440.01	LNG Gas - Land - Mt. Hayes								
448.65	Inspections				338,756				
460.00	Transmission Plant - Land				502,987				
461.01	Transmission Plant - Land Rights				1,766,391				
461.02	Transmission Plant - Land Rights - Mt. Hayes								
461.10	Transmission Plant - Land Rights - Byron Creek				18,595				
461.13	IP Land Rights - Whistler								
465.10	Transmission Plant - Transmission Pipeline - Byron Creek				1,290,115				
465.20	Inspections			11,912,000					
466.10	Compressor Overhaul				2,708,292				
467.30	Transmission Plant - Measuring and Regulating Equipment - Byron Creek				16,587				
470.00	Distribution System - Land			65,734	(12,821)				
471.01	Distribution System - Land Rights			11,155,845	247,716				
471.10	Distribution System - Land Rights - Byron Creek			2,857,393	1,370				
472.10	Distribution System - Structures - Byron Creek			(187,804,927)	59,477				
477.30	Measuring and Regulating Rquipment - Byron Creek			20,877,961	209,911				
480.00	General Plant - Land				17,122				
482.30	Structures (Leased)				2,903,926				
484.10	Capital Lease Vehicles				19,862,616				
TOTAL PLANT NOT STUDIED				**(140,935,993.13)**	**31,198,204**				
TOTAL PLANT				**5,711,012,826.46**	**1,919,586,981**				

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SCHEDULE 1A. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017
DEPRECIATION RELATED TO RECOVERY OF COST OF REMOVAL

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
LNG PLANT									
442.00	Structures	25-L2	-10	5,209,412	107,124	413,817	35,333	0.68	2.88
442.01	Structures - Mt. Hayes	25-L2	-10	19,038,721	77,894	1,825,978	93,054	0.49	4.33
443.00	Equipment	40-S4	-20	16,713,755	404,216	2,938,535	187,499	1.12	2.35
443.05	Equipment - Mt. Hayes	60-R5	-20	60,659,737	210,393	11,921,554	220,578	0.36	2.01
448.10	Piping	40-R3	-10	12,433,032	31,019	1,212,285	35,094	0.28	2.73
448.20	Pre-Treatment	25-R3	-10	29,241,933	132,082	2,792,111	144,822	0.50	4.34
448.30	Liquefaction Equipment	40-R3	-20	28,883,117	155,053	5,621,570	164,470	0.57	3.02
448.40	Send Out Equipment	40-R2	-10	23,555,076	61,993	2,293,515	65,955	0.28	2.69
448.50	Substation and Electrical	40-R2	-20	21,790,943	116,877	4,241,311	122,219	0.56	2.97
449.00	Other Equipment	27-R3	-10	25,739,908	609,578	1,964,413	211,155	0.82	3.59
449.01	Other Equipment - Mt. Hayes	33-R3	-10	5,600,437	17,818	542,226	17,741	0.32	3.40
TOTAL LNG PLANT				**248,866,073**	**1,924,047**	**35,767,315**	**1,297,921**	**0.52**	
TRANSMISSION PLANT									
462.00	Compressor Structures	30-S4	-3	31,562,024	460,094	486,767	35,998	0.11	3.44
463.00	Measuring and Regulating Structures	38-S2	-15	15,076,202	220,661	2,040,769	93,388	0.62	2.75
464.00	Other Structures	30-R4	-5	6,768,180	44,193	294,216	19,903	0.29	3.91
465.00	Transmission Pipeline	65-R4	-20	1,371,509,954	11,189,760	263,112,231	5,786,973	0.42	1.89
465.11	Intermediate Pipe - Whistler	65-R3	-20	42,295,869	143,778	8,315,396	145,362	0.34	1.88
465.30	Mains - Mt. Hayes	65-SQ	-20	6,307,725	20,156	1,241,389	19,098	0.30	1.54
466.00	Compressor Equipment	37-R4	-3	190,510,140	2,625,925	3,089,379	139,368	0.07	2.49
467.00	Measuring and Regulating Equipment - Mt. Hayes	37-R1.5	-7	5,340,973	11,218	362,650	11,276	0.21	2.56
467.10	Measuring and Regulating Equipment	37-R1.5	-5	62,016,326	488,524	2,612,293	101,496	0.16	2.28
467.31	Measuring and Regulating Equipment - Whistler	37-S1.5	-7	313,344	(689)	22,623	1,106	0.35	2.61
TOTAL TRANSMISSION PLANT				**1,731,700,735**	**15,203,618**	**281,577,714**	**6,353,968**	**0.37**	
DISTRIBUTION PLANT									
472.00	Structures	38-R1.5	-15	25,234,840	198,267	3,586,959	130,627	0.52	2.66
473.00	Services	47-R2	-70	1,160,659,173	22,727,803	789,733,618	24,203,889	2.09	4.27
474.00	Meter/Regulator Installations	20-S0/23-SQ	-20	188,387,340	(7,465,341)	45,142,809	6,339,569	3.37	10.81
475.00	Systems - Mains	65-R2.5	-25	1,427,597,191	22,972,831	333,926,467	7,079,542	0.50	1.85
477.10	Measuring and Regulating	33-R2	-12	143,051,691	2,478,559	14,687,643	650,510	0.45	2.97
477.20	Telemetry	20-R3	-5	14,930,538	18,319	728,208	71,647	0.48	4.07
TOTAL DISTRIBUTION PLANT				**2,959,860,773**	**40,930,438**	**1,187,805,705**	**38,475,783**	**1.30**	
BIO GAS									
418.20	Purification Upgrader	20-SQ	-5	9,794,870	20,996	468,747	23,437	0.24	5.00
472.20	Structures and Improvements	36-R1.5	-10	654,898	2,261	63,228	1,912	0.29	2.98
474.10	Meters/Regulator Installations	19-S0	-25	226,054	3,355	53,158	3,252	1.44	6.76
475.10	Mains - Municipal Land	65-R2.5	-25	1,655,815	17,279	396,674	6,439	0.39	1.95
TOTAL BIO GAS				**12,331,636**	**43,892**	**981,808**	**35,041**	**0.28**	
GENERAL PLANT									
482.10	Stuctures (Frame)	25-R1.5	-4	23,263,706	(282,314)	1,212,862	86,072	0.37	3.54
482.20	Structures (Masonry)	60-R2	-4	114,701,266	257,818	4,330,233	87,940	0.08	1.60
484.00	Vehicles	7-L1	15	20,521,572	569,350	- 3,647,586	(759,184)	(3.70)	7.37
485.10	Heavy Work Equipment	13-L0.5	5	905,623	1,162	- 46,443	(6,101)	(0.67)	4.47
485.20	Heavy Mobile Equipment	9-L1.5	15	5,384,508	(169,259)	- 638,417	(96,895)	(1.80)	4.29
TOTAL GENERAL PLANT				**164,776,676**	**376,757**	**1,210,649**	**(688,169)**	**(0.42)**	
TOTAL DEPRECIABLE PLANT				**5,117,535,893**	**58,478,752**	**1,507,343,191**	**45,474,544**	**0.89**	
TOTAL PLANT				**5,117,535,893**	**58,478,752**				

SECTION 6

6 ACTUARIAL ANALYSIS CALCULATIONS

FortisBC Energy

Account #: 44200 - LNG Plant - Structures

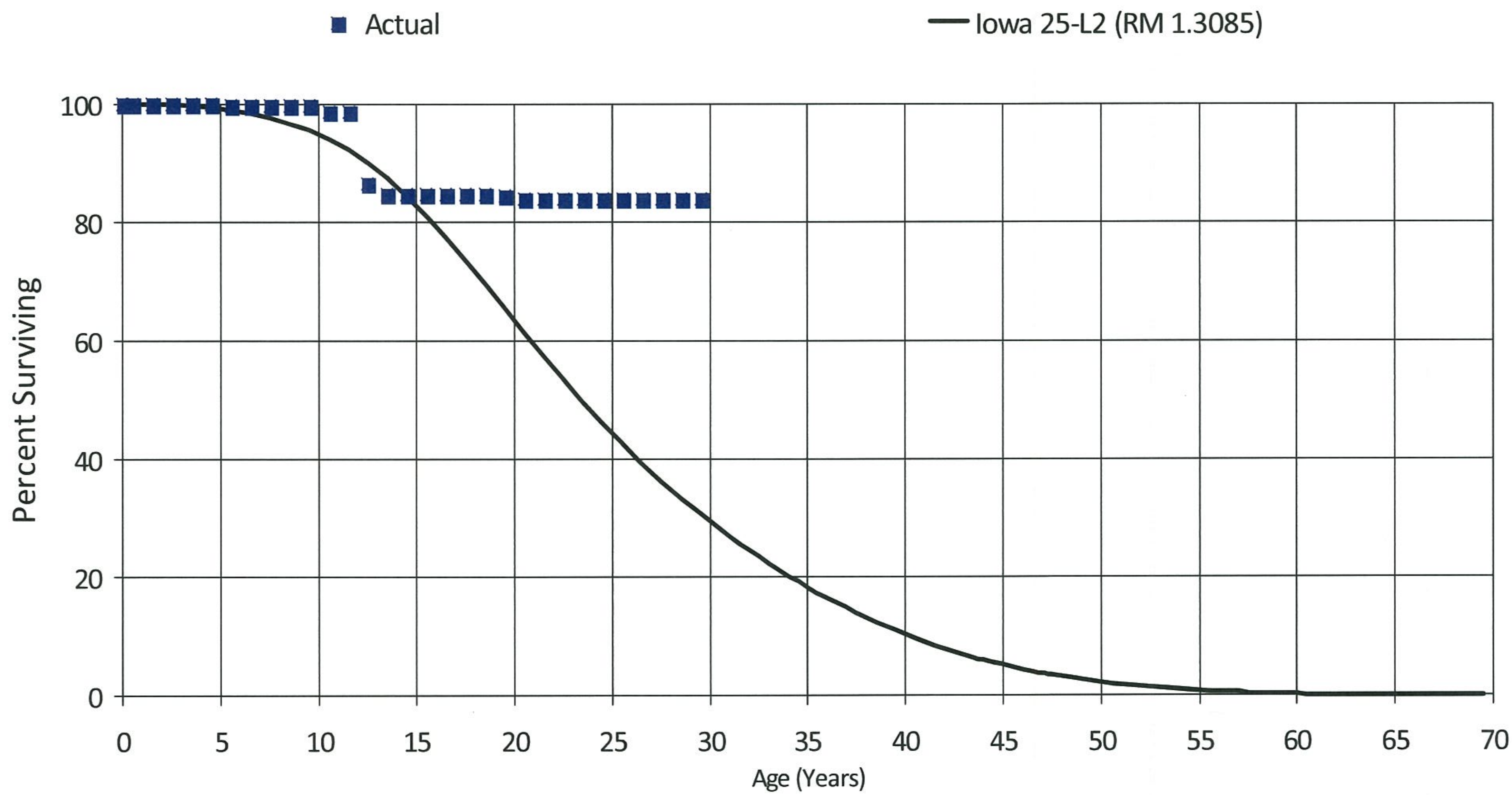
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,095,726	0	0.0000	1.0000	100.00
0.5	6,094,765	0	0.0000	1.0000	100.00
1.5	6,067,819	0	0.0000	1.0000	100.00
2.5	6,052,697	0	0.0000	1.0000	100.00
3.5	5,845,777	0	0.0000	1.0000	100.00
4.5	5,845,777	11,458	0.0020	0.9980	100.00
5.5	5,834,319	0	0.0000	1.0000	99.80
6.5	5,834,319	0	0.0000	1.0000	99.80
7.5	5,759,436	0	0.0000	1.0000	99.80
8.5	5,759,435	1,000	0.0002	0.9998	99.80
9.5	5,728,074	61,358	0.0107	0.9893	99.78
10.5	5,396,114	0	0.0000	1.0000	98.71
11.5	5,382,502	669,121	0.1243	0.8757	98.71
12.5	3,877,309	74,954	0.0193	0.9807	86.44
13.5	3,785,359	0	0.0000	1.0000	84.77
14.5	3,081,103	2,477	0.0008	0.9992	84.77
15.5	3,042,092	0	0.0000	1.0000	84.70
16.5	2,947,273	0	0.0000	1.0000	84.70
17.5	2,628,524	1,959	0.0008	0.9993	84.70
18.5	2,492,672	6,000	0.0024	0.9976	84.64
19.5	2,089,926	10,373	0.0050	0.9950	84.44
20.5	1,833,440	0	0.0000	1.0000	84.02
21.5	1,790,660	0	0.0000	1.0000	84.02
22.5	1,658,079	0	0.0000	1.0000	84.02
23.5	1,573,517	0	0.0000	1.0000	84.02
24.5	1,565,423	0	0.0000	1.0000	84.02
25.5	1,454,996	0	0.0000	1.0000	84.02
26.5	1,453,071	0	0.0000	1.0000	84.02
27.5	1,453,071	0	0.0000	1.0000	84.02
28.5	1,453,071	0	0.0000	1.0000	84.02
29.5	0	0	0.0000	0.0000	84.02

FortisBC Energy

Account #: 44200 - LNG Plant - Structures

Actual and Smooth Survivor Curves

Placement Band - 1972 - 2017   Experience Band - 1985 - 2017



FortisBC Energy

Account #: 44201 - LNG Plant - Structures - Mt. Hayes

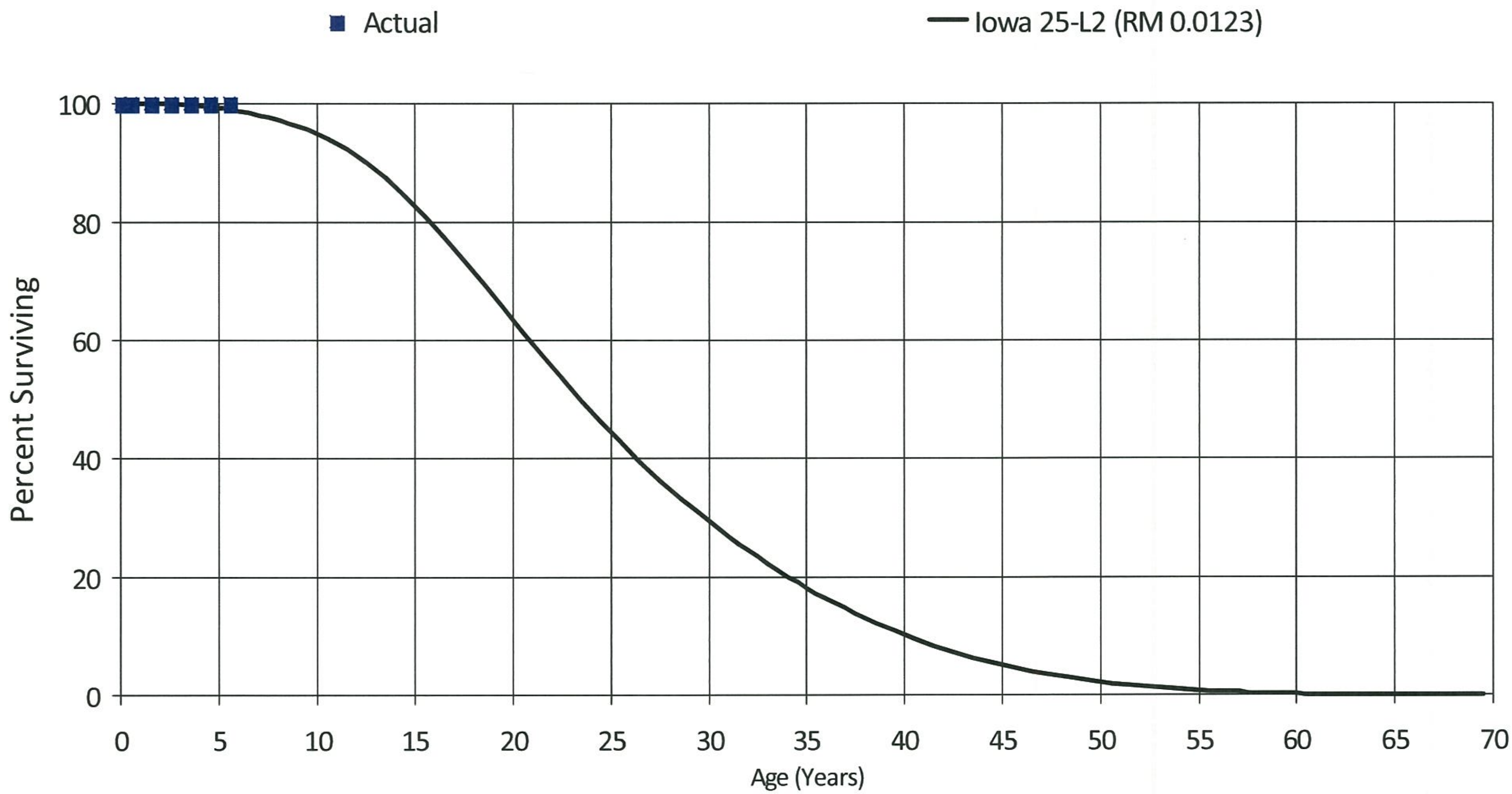
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	19,038,721	0	0.0000	1.0000	100.00
0.5	18,670,714	0	0.0000	1.0000	100.00
1.5	18,166,491	0	0.0000	1.0000	100.00
2.5	17,307,739	0	0.0000	1.0000	100.00
3.5	17,281,611	0	0.0000	1.0000	100.00
4.5	17,258,994	0	0.0000	1.0000	100.00
5.5	17,258,994	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44201 - LNG Plant - Structures - Mt. Hayes

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44300 - LNG Plant - Equipment

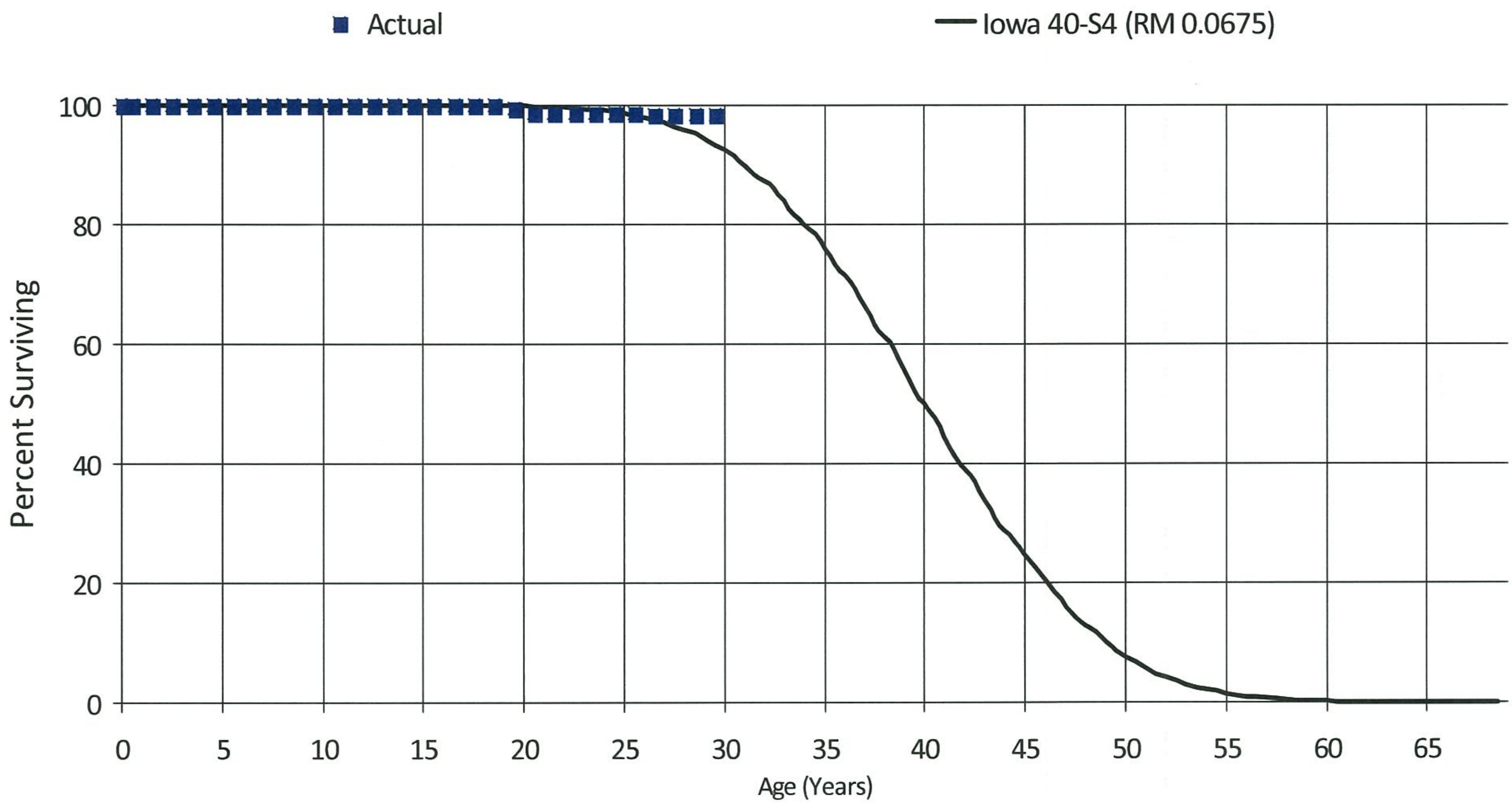
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,858,466	0	0.0000	1.0000	100.00
0.5	16,849,739	0	0.0000	1.0000	100.00
1.5	16,711,010	0	0.0000	1.0000	100.00
2.5	16,643,327	0	0.0000	1.0000	100.00
3.5	16,643,327	0	0.0000	1.0000	100.00
4.5	16,693,071	1,000	0.0001	0.9999	100.00
5.5	16,692,071	0	0.0000	1.0000	99.99
6.5	16,687,472	0	0.0000	1.0000	99.99
7.5	16,687,472	0	0.0000	1.0000	99.99
8.5	16,687,472	0	0.0000	1.0000	99.99
9.5	16,687,472	12,708	0.0008	0.9992	99.99
10.5	16,674,504	0	0.0000	1.0000	99.91
11.5	16,623,006	0	0.0000	1.0000	99.91
12.5	16,623,006	0	0.0000	1.0000	99.91
13.5	16,424,228	0	0.0000	1.0000	99.91
14.5	16,240,687	0	0.0000	1.0000	99.91
15.5	10,936,617	1,734	0.0002	0.9998	99.91
16.5	10,832,588	0	0.0000	1.0000	99.89
17.5	10,750,667	0	0.0000	1.0000	99.89
18.5	10,003,933	44,685	0.0045	0.9955	99.89
19.5	9,856,823	79,648	0.0081	0.9919	99.44
20.5	9,592,571	0	0.0000	1.0000	98.64
21.5	9,199,099	0	0.0000	1.0000	98.64
22.5	9,199,099	0	0.0000	1.0000	98.64
23.5	9,199,099	0	0.0000	1.0000	98.64
24.5	9,136,647	0	0.0000	1.0000	98.64
25.5	9,109,307	27,340	0.0030	0.9970	98.64
26.5	9,052,020	0	0.0000	1.0000	98.34
27.5	9,052,020	0	0.0000	1.0000	98.34
28.5	9,052,020	0	0.0000	1.0000	98.34
29.5	0	0	0.0000	0.0000	98.34

FortisBC Energy

Account #: 44300 - LNG Plant - Equipment

Actual and Smooth Survivor Curves

Placement Band - 1972 - 2017   Experience Band - 1998 - 2017



FortisBC Energy

Account #: 44305 - LNG Plant - Equipment - Mt. Hayes

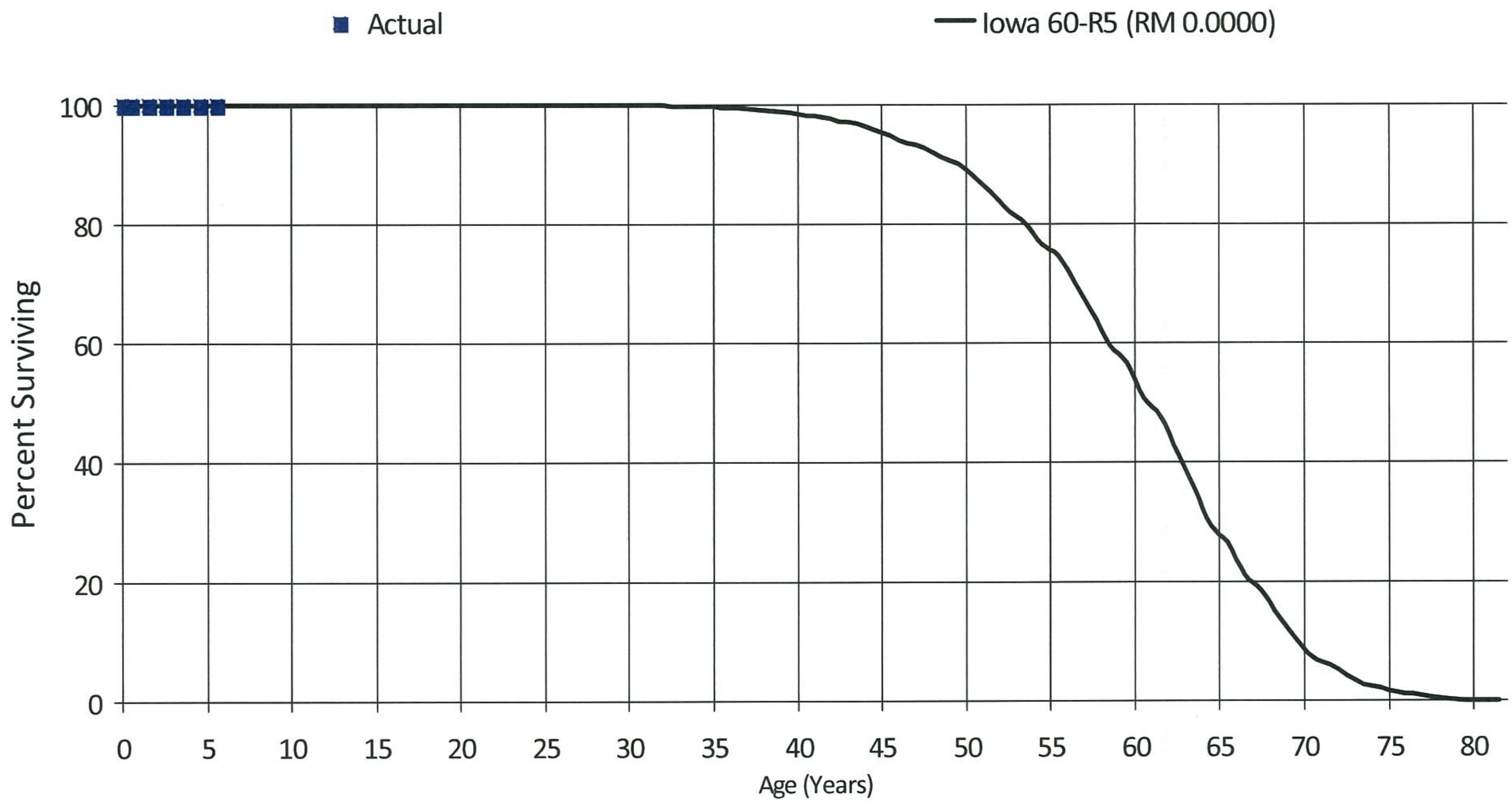
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	60,659,737	0	0.0000	1.0000	100.00
0.5	60,292,553	0	0.0000	1.0000	100.00
1.5	60,136,843	0	0.0000	1.0000	100.00
2.5	60,103,832	0	0.0000	1.0000	100.00
3.5	60,103,832	0	0.0000	1.0000	100.00
4.5	60,103,832	0	0.0000	1.0000	100.00
5.5	60,103,832	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44305 - LNG Plant - Equipment - Mt. Hayes

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44810 - LNG Plant - Piping

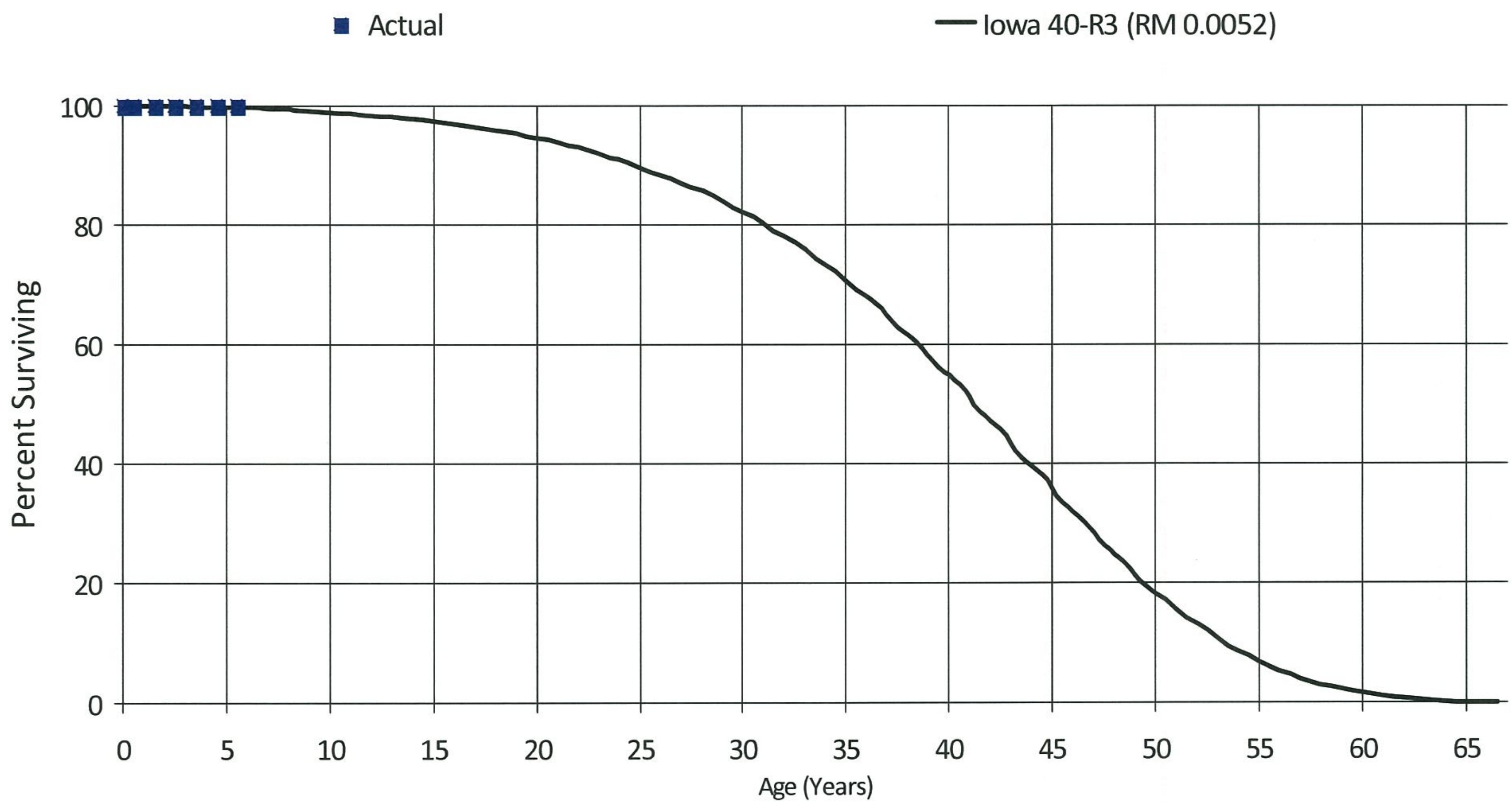
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	12,433,032	0	0.0000	1.0000	100.00
0.5	11,532,521	0	0.0000	1.0000	100.00
1.5	11,532,521	0	0.0000	1.0000	100.00
2.5	11,486,806	0	0.0000	1.0000	100.00
3.5	11,486,806	0	0.0000	1.0000	100.00
4.5	11,486,806	0	0.0000	1.0000	100.00
5.5	11,486,806	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44810 - LNG Plant - Piping

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44820 - LNG Plant - Pre-Treatment

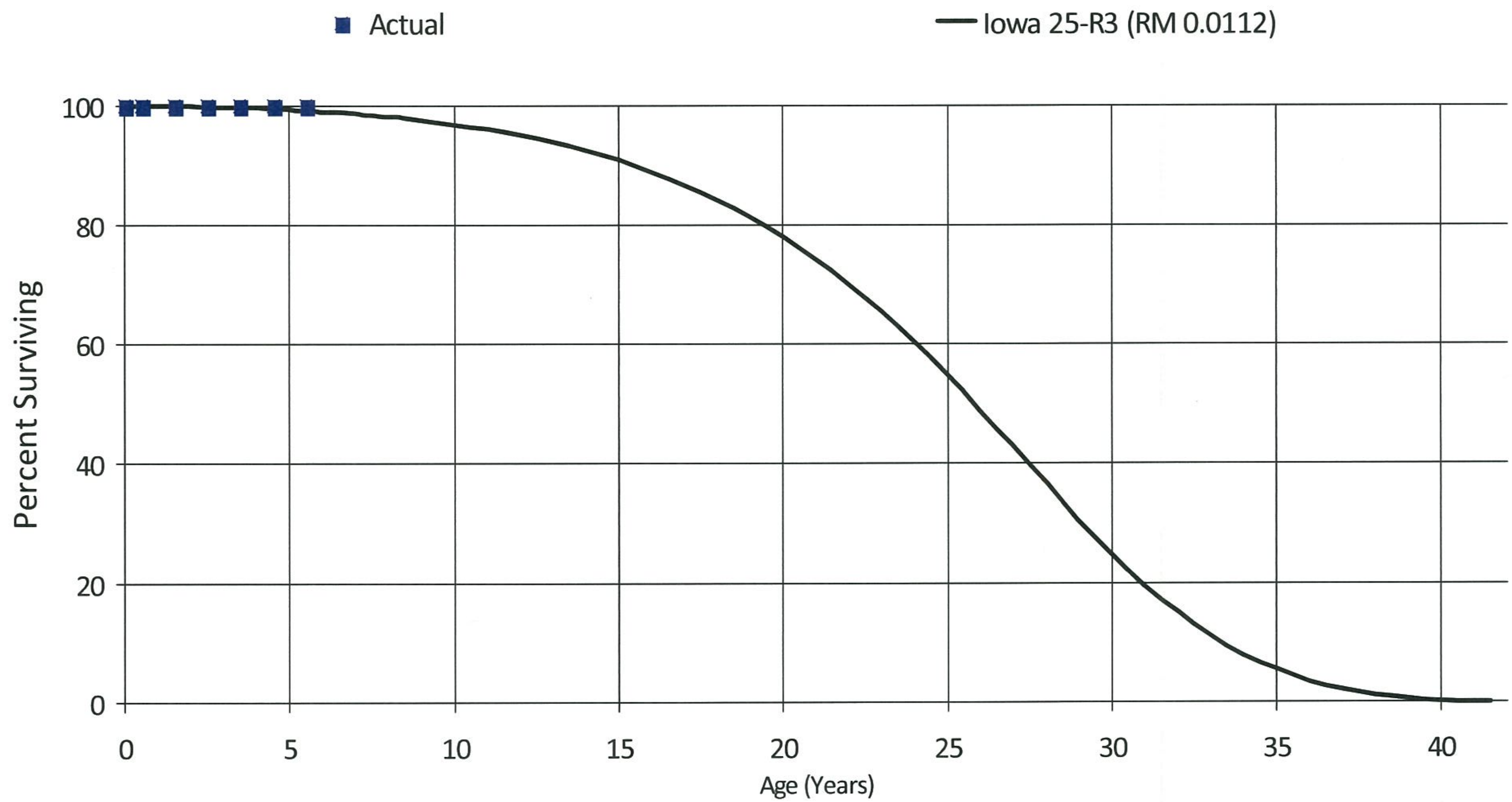
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	29,241,933	0	0.0000	1.0000	100.00
0.5	29,224,597	0	0.0000	1.0000	100.00
1.5	28,994,003	0	0.0000	1.0000	100.00
2.5	28,709,485	0	0.0000	1.0000	100.00
3.5	28,709,485	0	0.0000	1.0000	100.00
4.5	28,709,485	0	0.0000	1.0000	100.00
5.5	28,709,485	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44820 - LNG Plant - Pre-Treatment

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44830 - LNG Plant - Liquefaction Equipment

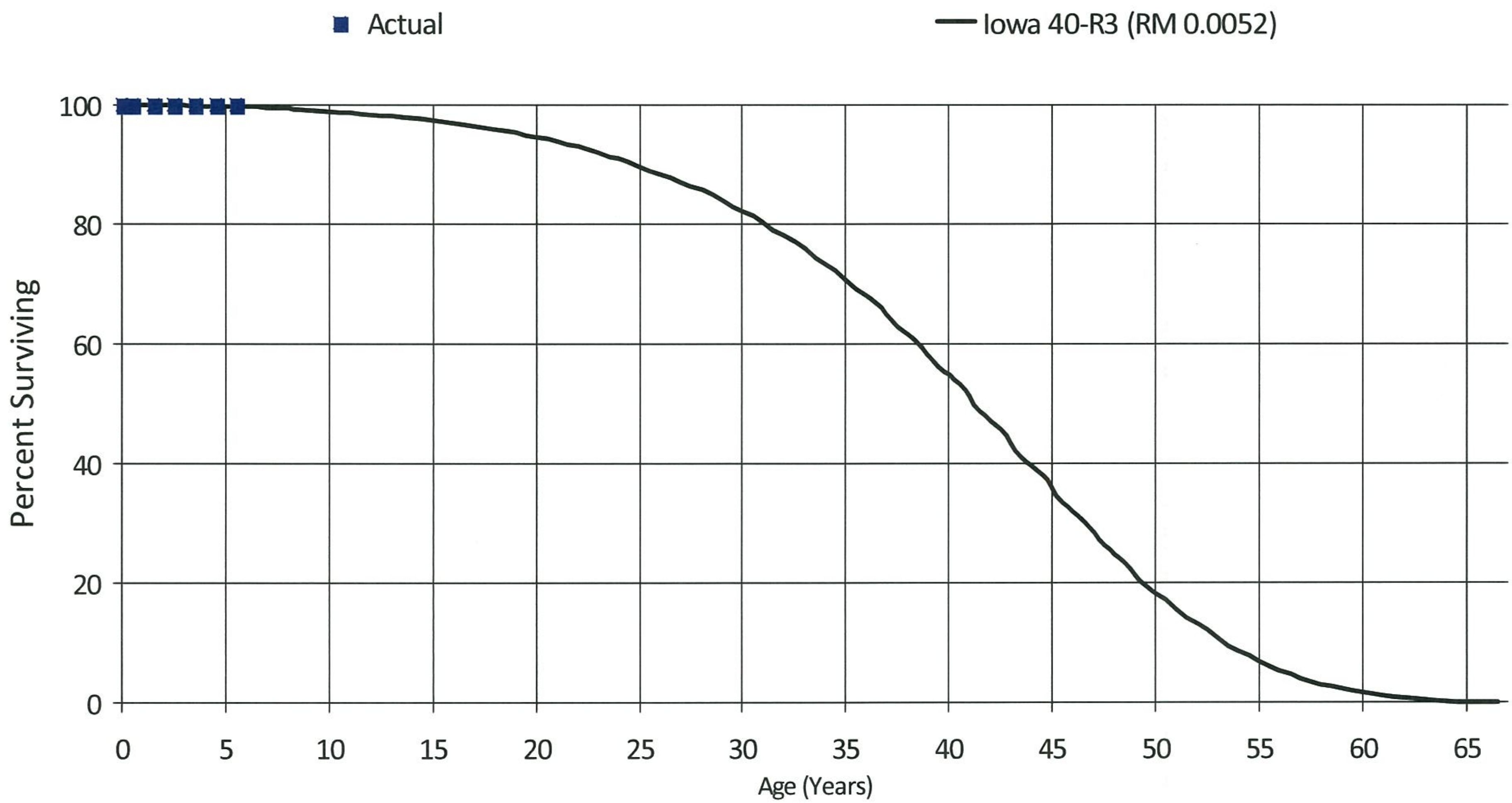
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	28,883,117	0	0.0000	1.0000	100.00
0.5	28,832,462	0	0.0000	1.0000	100.00
1.5	28,832,462	0	0.0000	1.0000	100.00
2.5	28,709,485	0	0.0000	1.0000	100.00
3.5	28,709,485	0	0.0000	1.0000	100.00
4.5	28,709,485	0	0.0000	1.0000	100.00
5.5	28,709,485	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44830 - LNG Plant - Liquefaction Equipment

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44840 - LNG Plant - Send Out Equipment

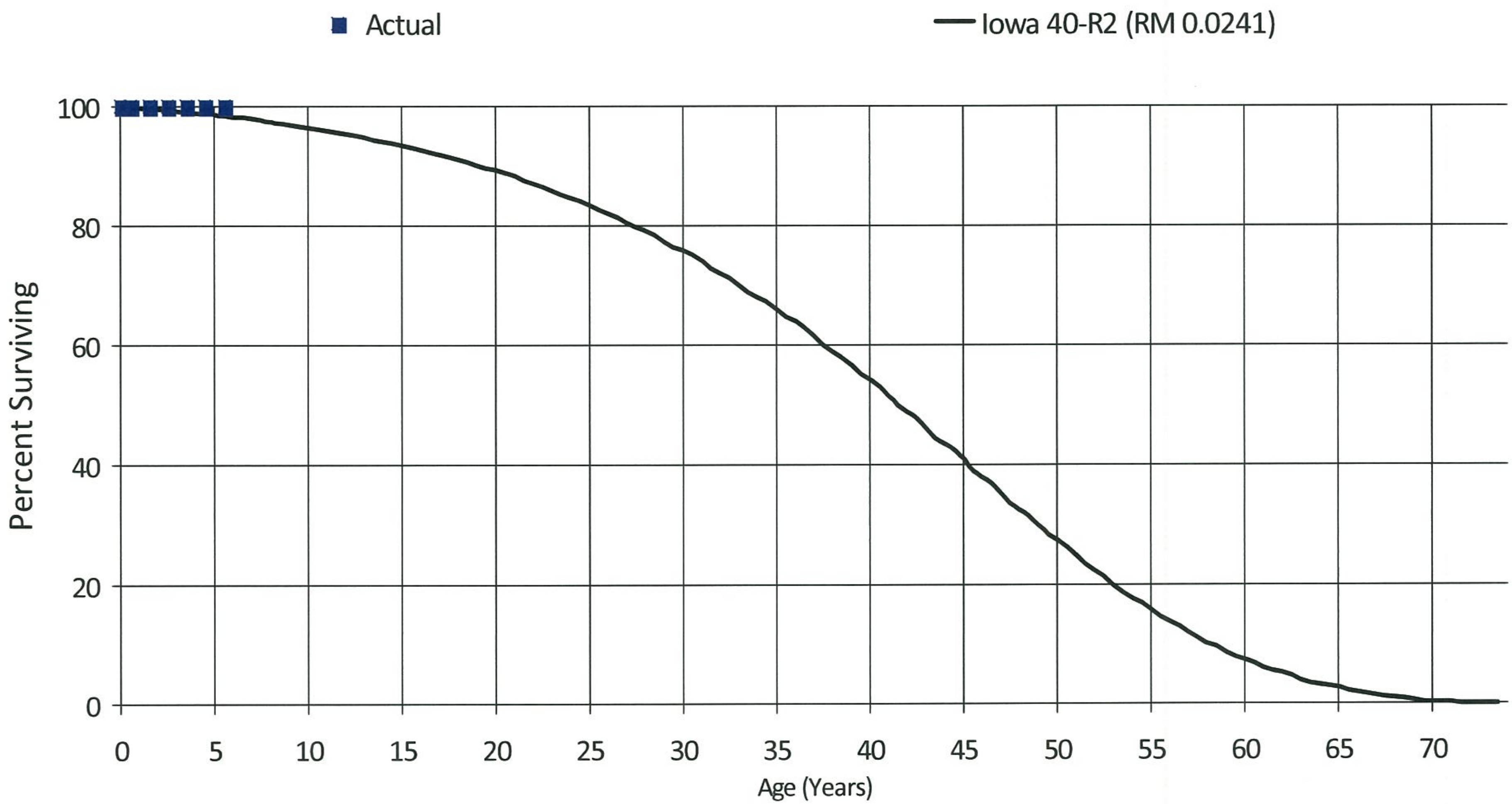
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	23,555,076	0	0.0000	1.0000	100.00
0.5	23,353,236	0	0.0000	1.0000	100.00
1.5	23,317,927	0	0.0000	1.0000	100.00
2.5	22,957,011	0	0.0000	1.0000	100.00
3.5	22,957,011	0	0.0000	1.0000	100.00
4.5	22,957,011	0	0.0000	1.0000	100.00
5.5	22,957,011	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44840 - LNG Plant - Send Out Equipment

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44850 - LNG Plant - Substation and Electrical

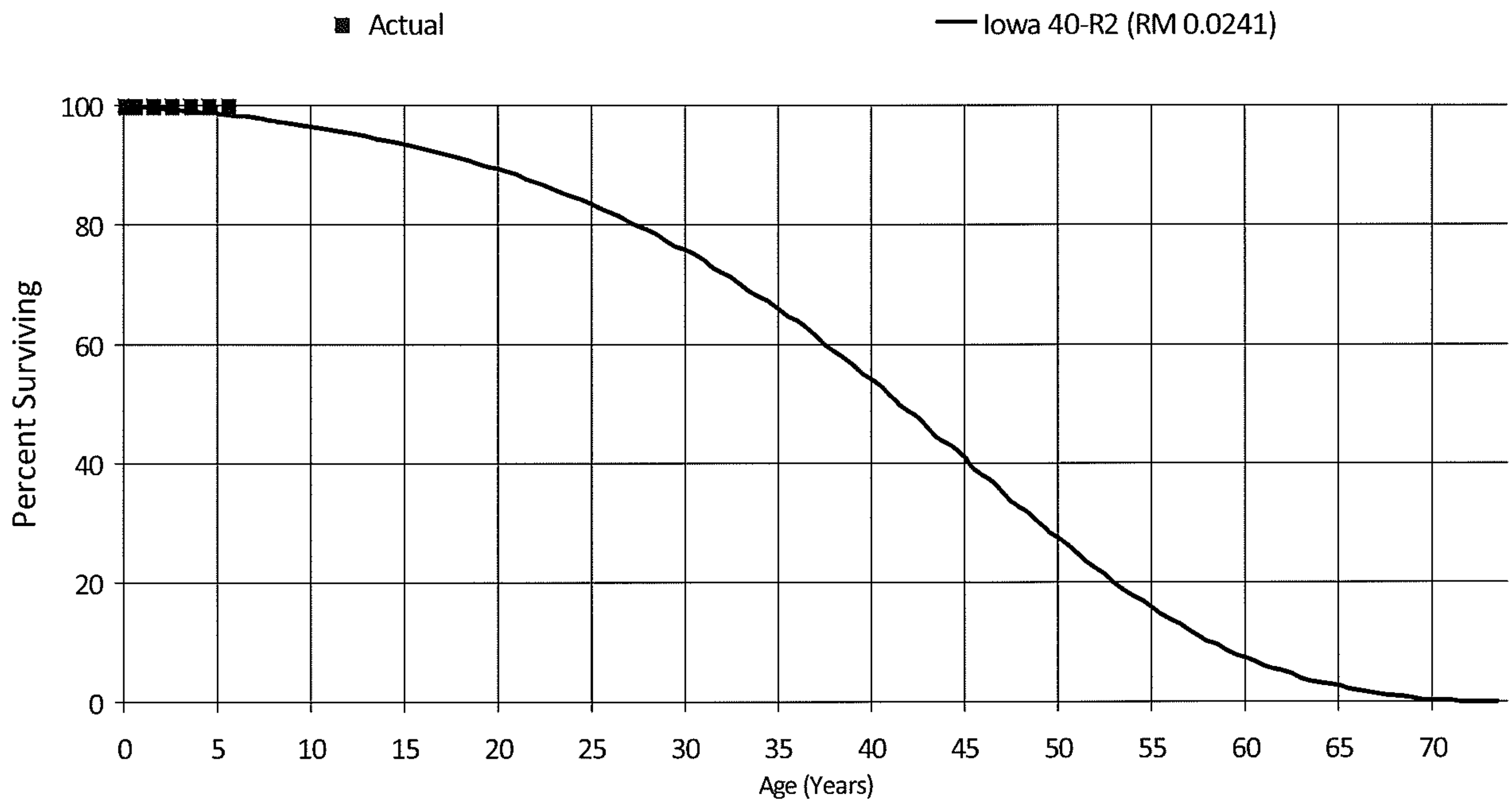
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	21,790,943	0	0.0000	1.0000	100.00
0.5	21,748,519	0	0.0000	1.0000	100.00
1.5	21,748,519	0	0.0000	1.0000	100.00
2.5	21,640,921	0	0.0000	1.0000	100.00
3.5	21,640,921	0	0.0000	1.0000	100.00
4.5	21,640,921	0	0.0000	1.0000	100.00
5.5	21,640,921	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44850 - LNG Plant - Substation and Electrical

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44860 - LNG Plant - Control Room

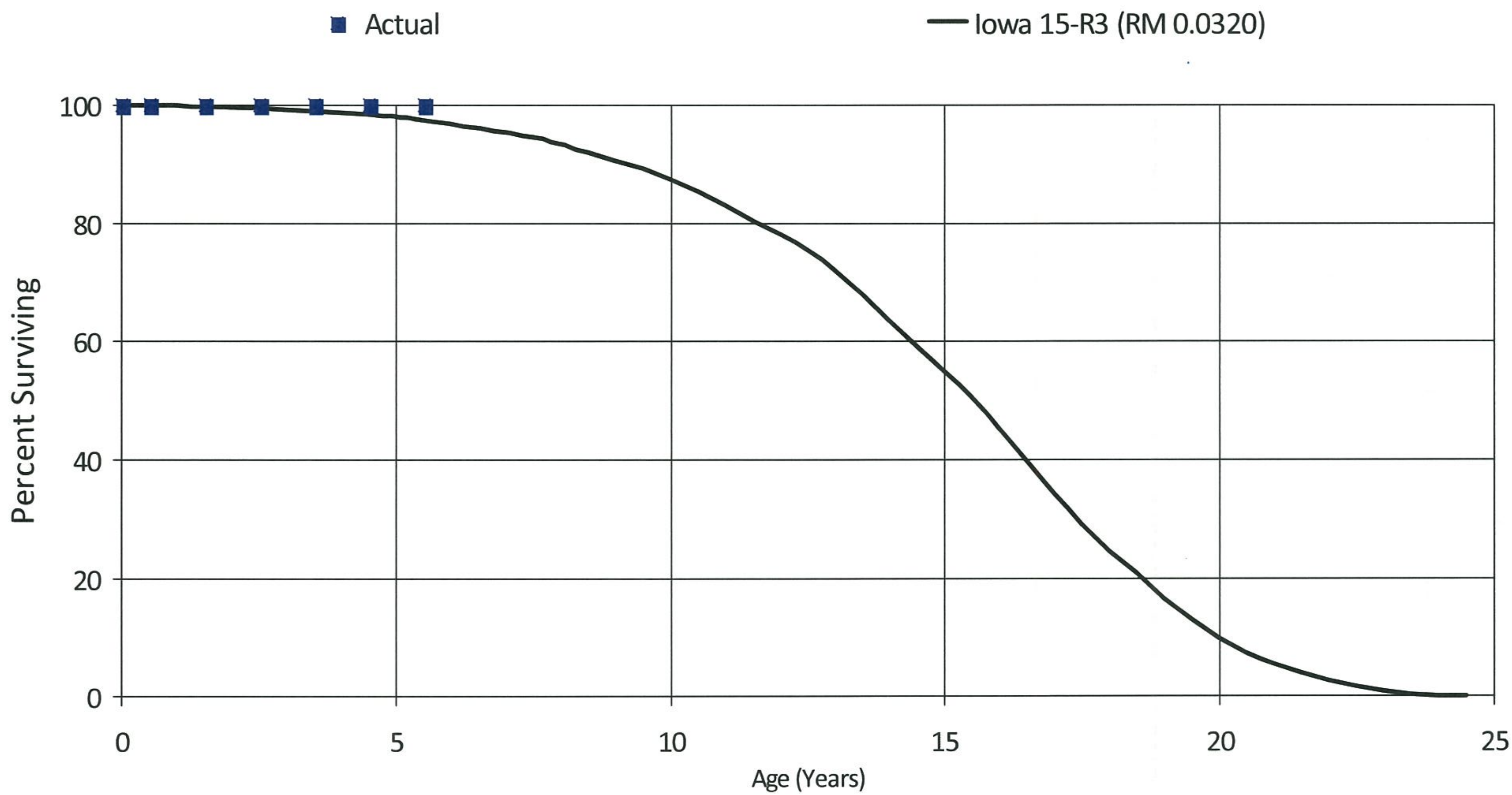
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,354,097	0	0.0000	1.0000	100.00
0.5	6,354,097	0	0.0000	1.0000	100.00
1.5	6,131,257	0	0.0000	1.0000	100.00
2.5	5,899,221	0	0.0000	1.0000	100.00
3.5	5,899,221	0	0.0000	1.0000	100.00
4.5	5,899,221	0	0.0000	1.0000	100.00
5.5	5,899,221	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44860 - LNG Plant - Control Room

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 44900 - LNG Plant - Other Equipment

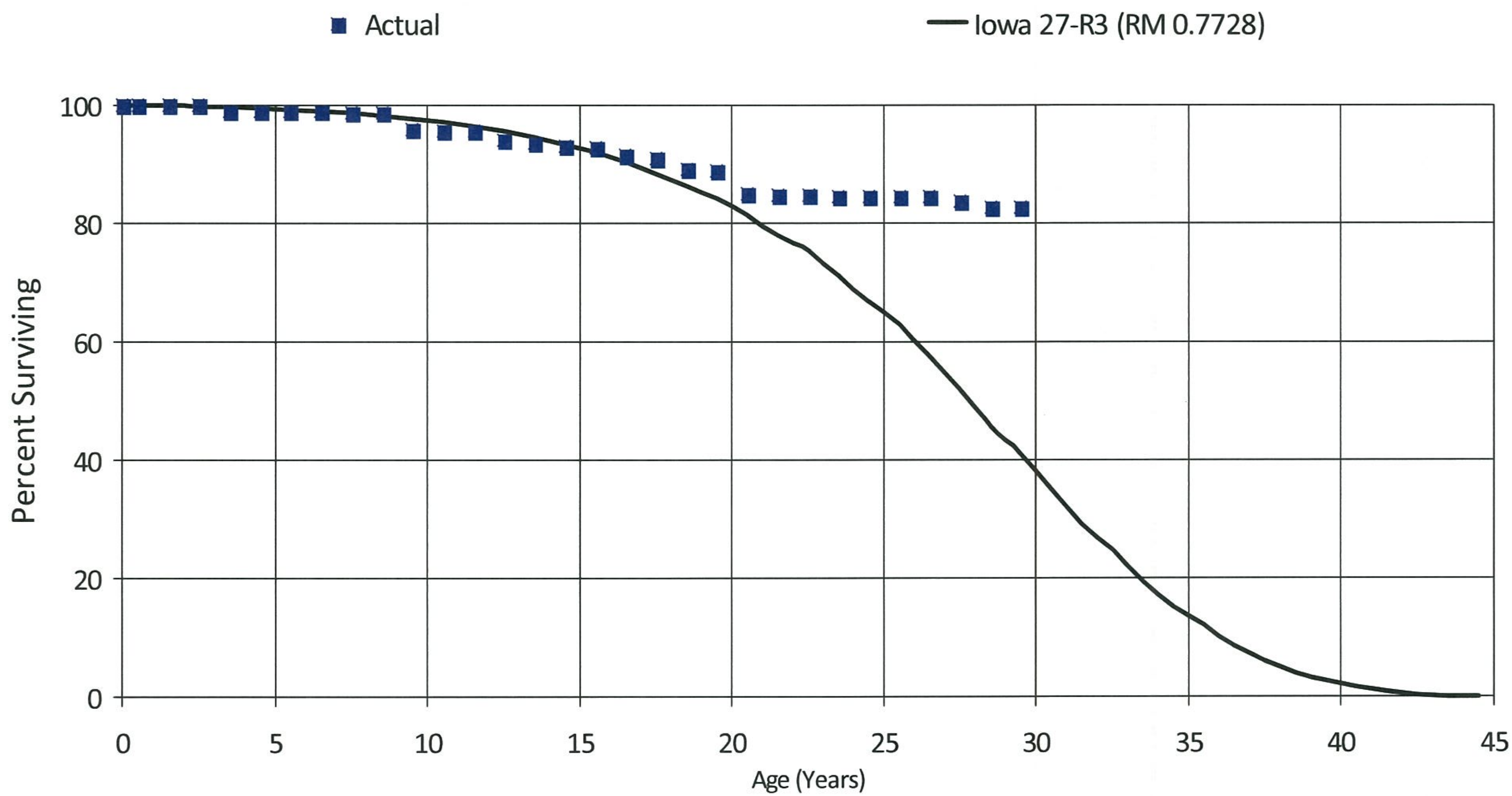
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	28,976,329	500	0.0000	1.0000	100.00
0.5	28,956,303	0	0.0000	1.0000	100.00
1.5	28,513,963	1	0.0000	1.0000	100.00
2.5	28,361,723	258,133	0.0091	0.9909	100.00
3.5	28,014,990	48	0.0000	1.0000	99.09
4.5	27,988,283	10,802	0.0004	0.9996	99.09
5.5	27,309,301	21,004	0.0008	0.9992	99.05
6.5	27,224,223	56,589	0.0021	0.9979	98.97
7.5	26,540,279	9,223	0.0004	0.9997	98.76
8.5	24,681,250	698,665	0.0283	0.9717	98.73
9.5	19,825,168	70,887	0.0036	0.9964	95.93
10.5	19,395,025	25,930	0.0013	0.9987	95.59
11.5	19,060,720	286,493	0.0150	0.9850	95.46
12.5	18,460,262	123,449	0.0067	0.9933	94.03
13.5	18,304,457	67,845	0.0037	0.9963	93.40
14.5	16,436,756	41,927	0.0026	0.9975	93.05
15.5	16,037,827	220,295	0.0137	0.9863	92.81
16.5	15,796,026	85,676	0.0054	0.9946	91.53
17.5	14,745,503	300,308	0.0204	0.9796	91.03
18.5	13,800,898	71,537	0.0052	0.9948	89.18
19.5	13,710,800	578,265	0.0422	0.9578	88.72
20.5	13,051,405	27,751	0.0021	0.9979	84.98
21.5	12,221,742	21,715	0.0018	0.9982	84.80
22.5	9,328,510	20,000	0.0021	0.9979	84.65
23.5	9,112,863	0	0.0000	1.0000	84.47
24.5	6,775,971	0	0.0000	1.0000	84.47
25.5	6,213,044	9	0.0000	1.0000	84.47
26.5	5,658,572	54,471	0.0096	0.9904	84.47
27.5	5,604,101	67,164	0.0120	0.9880	83.66
28.5	5,536,937	0	0.0000	1.0000	82.66
29.5	0	0	0.0000	0.0000	82.66

FortisBC Energy

Account #: 44900 - LNG Plant - Other Equipment

Actual and Smooth Survivor Curves

Placement Band - 1970 - 2017 Experience Band - 1985 - 2017



FortisBC Energy

Account #: 44901 - LNG Plant - Other Equipment - Mt. Hayes

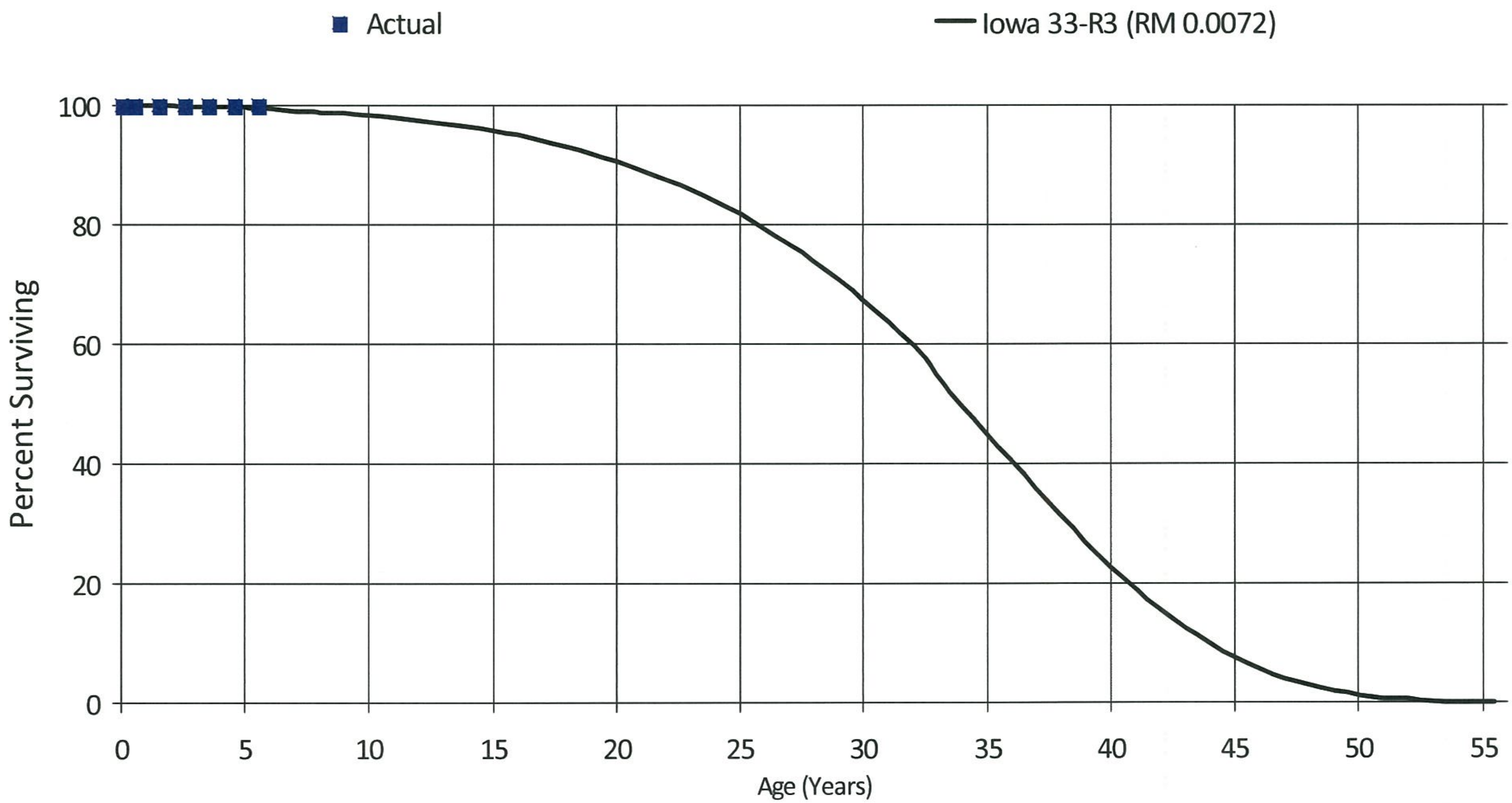
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,600,437	0	0.0000	1.0000	100.00
0.5	5,592,021	0	0.0000	1.0000	100.00
1.5	5,232,914	0	0.0000	1.0000	100.00
2.5	2,958,920	0	0.0000	1.0000	100.00
3.5	33,242	0	0.0000	1.0000	100.00
4.5	33,242	0	0.0000	1.0000	100.00
5.5	33,242	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 44901 - LNG Plant - Other Equipment - Mt. Hayes

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 46200 - Transmission Plant - Compressor Structures

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	32,192,648	458	0.0000	1.0000	100.00
0.5	32,136,216	0	0.0000	1.0000	100.00
1.5	30,822,393	1,338	0.0000	1.0000	100.00
2.5	30,398,476	0	0.0000	1.0000	100.00
3.5	30,240,787	1,225	0.0000	1.0000	100.00
4.5	29,577,490	7,893	0.0003	0.9997	100.00
5.5	27,637,858	6,379	0.0002	0.9998	99.97
6.5	27,064,959	2,414	0.0001	0.9999	99.95
7.5	26,837,227	659	0.0000	1.0000	99.94
8.5	26,386,312	3,363	0.0001	0.9999	99.94
9.5	26,206,149	3,380	0.0001	0.9999	99.93
10.5	24,541,505	6,438	0.0003	0.9997	99.92
11.5	24,482,222	288,000	0.0118	0.9882	99.89
12.5	24,194,222	1,162	0.0001	1.0000	98.72
13.5	24,025,339	15,868	0.0007	0.9993	98.72
14.5	23,898,095	13,625	0.0006	0.9994	98.65
15.5	21,955,996	1,961	0.0001	0.9999	98.59
16.5	21,168,357	3,140	0.0002	0.9999	98.58
17.5	16,817,335	458,159	0.0272	0.9728	98.57
18.5	13,808,955	0	0.0000	1.0000	95.88
19.5	10,479,906	0	0.0000	1.0000	95.88
20.5	10,084,974	0	0.0000	1.0000	95.88
21.5	9,652,000	0	0.0000	1.0000	95.88
22.5	5,027,371	0	0.0000	1.0000	95.88
23.5	3,580,341	0	0.0000	1.0000	95.88
24.5	2,397,634	0	0.0000	1.0000	95.88
25.5	2,146,598	0	0.0000	1.0000	95.88
26.5	293,960	0	0.0000	1.0000	95.88
27.5	262,661	0	0.0000	1.0000	95.88
28.5	260,102	0	0.0000	1.0000	95.88
29.5	257,546	0	0.0000	1.0000	95.88
30.5	257,546	0	0.0000	1.0000	95.88
31.5	257,546	0	0.0000	1.0000	95.88
32.5	257,546	0	0.0000	1.0000	95.88
33.5	256,651	0	0.0000	1.0000	95.88
34.5	256,651	0	0.0000	1.0000	95.88
35.5	255,405	0	0.0000	1.0000	95.88
36.5	255,405	0	0.0000	1.0000	95.88
37.5	254,790	0	0.0000	1.0000	95.88
38.5	254,790	0	0.0000	1.0000	95.88
39.5	248,874	0	0.0000	1.0000	95.88
40.5	248,807	0	0.0000	1.0000	95.88
41.5	248,807	0	0.0000	1.0000	95.88
42.5	242,648	0	0.0000	1.0000	95.88
43.5	242,648	27,247	0.1123	0.8877	95.88

FortisBC Energy

Account #: 46200 - Transmission Plant - Compressor Structures

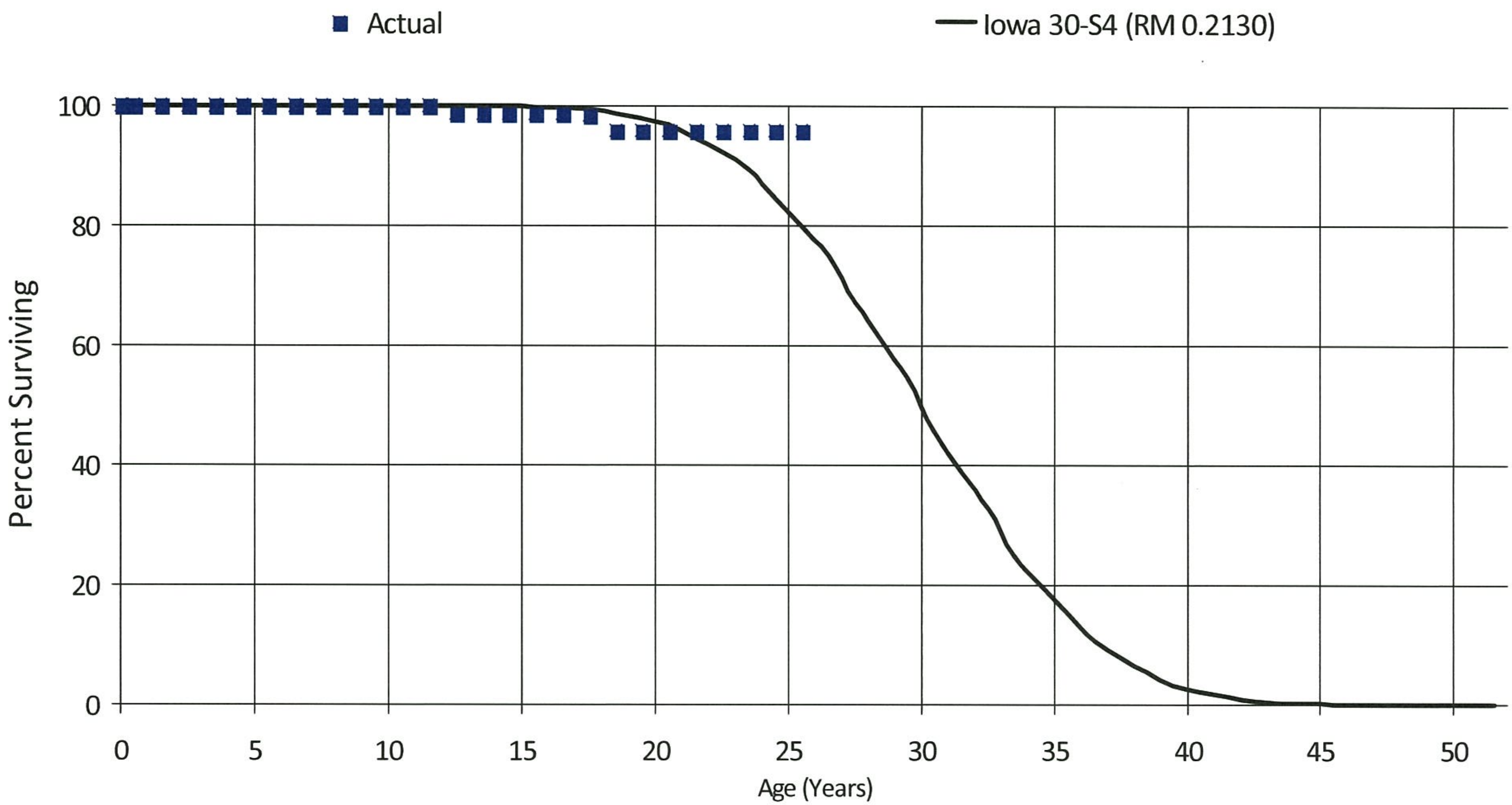
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	0	0	0.0000	0.0000	85.11

FortisBC Energy

Account #: 46200 - Transmission Plant - Compressor Structures

Actual and Smooth Survivor Curves

Placement Band - 1965 - 2017 Experience Band - 1974 - 2017



FortisBC Energy

Account #: 46300 - Transmission Plant - Measuring and Regulating Structures

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,835,158	53,753	0.0034	0.9966	100.00
0.5	15,422,040	3	0.0000	1.0000	99.66
1.5	15,155,316	23	0.0000	1.0000	99.66
2.5	14,738,955	142	0.0000	1.0000	99.66
3.5	14,612,631	167	0.0000	1.0000	99.66
4.5	13,713,804	617	0.0000	1.0000	99.66
5.5	13,578,729	244	0.0000	1.0000	99.66
6.5	13,428,181	6,386	0.0005	0.9995	99.66
7.5	13,086,154	17,727	0.0014	0.9987	99.61
8.5	12,915,400	48,726	0.0038	0.9962	99.48
9.5	12,757,369	4,013	0.0003	0.9997	99.10
10.5	10,995,910	544	0.0001	1.0000	99.07
11.5	9,209,869	437	0.0001	1.0000	99.07
12.5	9,054,868	36,190	0.0040	0.9960	99.07
13.5	8,652,415	955	0.0001	0.9999	98.67
14.5	8,447,511	22,233	0.0026	0.9974	98.66
15.5	7,614,818	100,090	0.0131	0.9869	98.40
16.5	7,408,867	113	0.0000	1.0000	97.11
17.5	7,009,448	59	0.0000	1.0000	97.11
18.5	6,389,200	265,851	0.0416	0.9584	97.11
19.5	6,002,817	41,956	0.0070	0.9930	93.07
20.5	5,739,227	10,287	0.0018	0.9982	92.42
21.5	5,377,459	6,227	0.0012	0.9988	92.25
22.5	4,898,794	18,950	0.0039	0.9961	92.14
23.5	4,808,648	22,385	0.0047	0.9953	91.78
24.5	4,612,207	3,756	0.0008	0.9992	91.35
25.5	4,346,797	3,000	0.0007	0.9993	91.28
26.5	323,067	32,532	0.1007	0.8993	91.22
27.5	285,287	0	0.0000	1.0000	82.03
28.5	283,385	0	0.0000	1.0000	82.03
29.5	128,940	0	0.0000	1.0000	82.03
30.5	120,536	0	0.0000	1.0000	82.03
31.5	119,171	622	0.0052	0.9948	82.03
32.5	115,506	322	0.0028	0.9972	81.60
33.5	106,267	0	0.0000	1.0000	81.37
34.5	106,267	0	0.0000	1.0000	81.37
35.5	105,021	1,000	0.0095	0.9905	81.37
36.5	104,021	0	0.0000	1.0000	80.60
37.5	102,359	54,267	0.5302	0.4698	80.60
38.5	48,092	230	0.0048	0.9952	37.87
39.5	47,862	0	0.0000	1.0000	37.69
40.5	47,862	0	0.0000	1.0000	37.69
41.5	47,862	0	0.0000	1.0000	37.69
42.5	47,862	0	0.0000	1.0000	37.69
43.5	35,325	0	0.0000	1.0000	37.69

FortisBC Energy

Account #: 46300 - Transmission Plant - Measuring and Regulating Structures

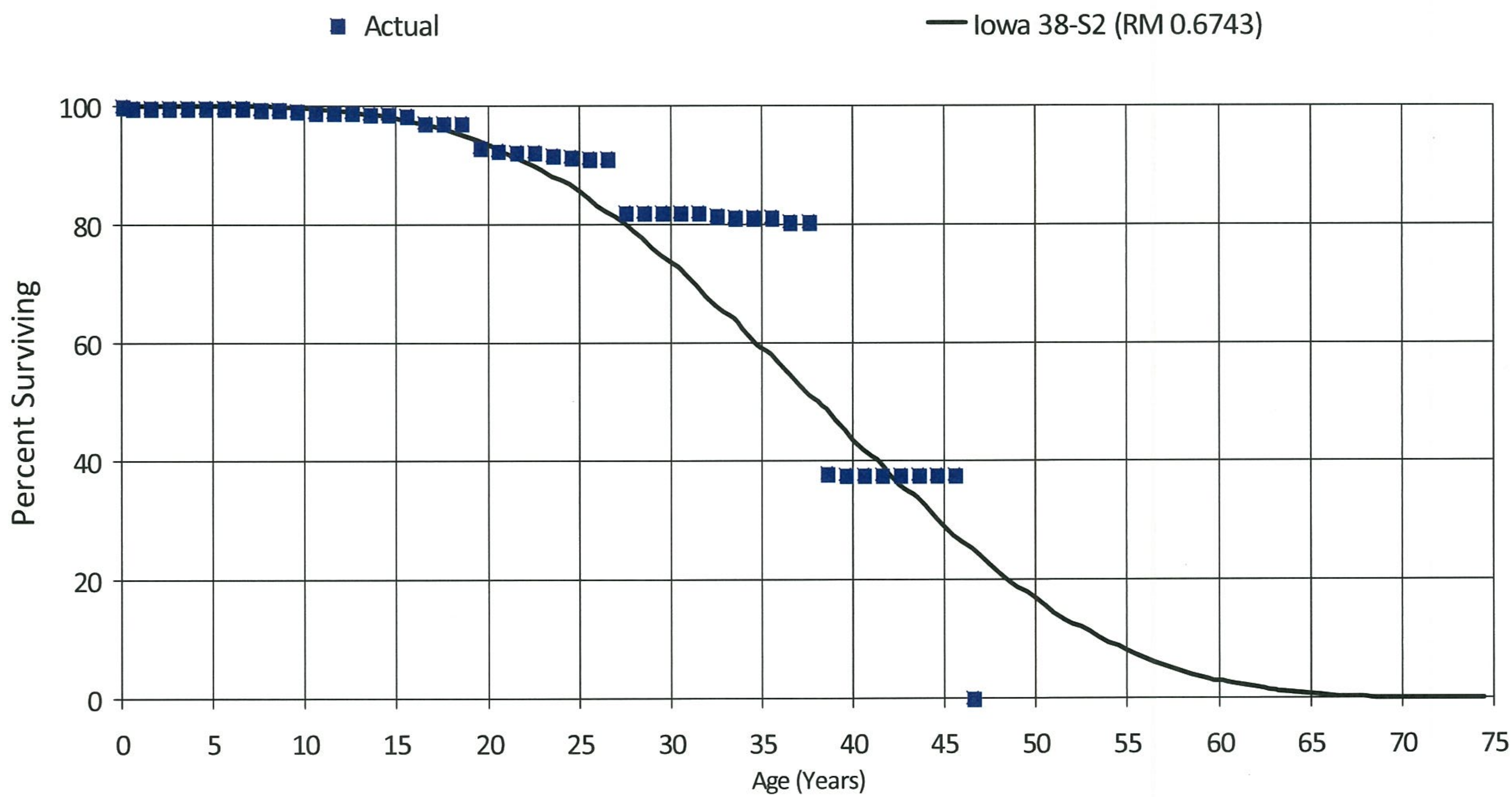
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	35,325	0	0.0000	1.0000	37.69
45.5	4,697	4,697	1.0000	0.0000	37.69
46.5	0	0	0.0000	0.0000	0.00

FortisBC Energy

Account #: 46300 - Transmission Plant - Measuring and Regulating Structures

Actual and Smooth Survivor Curves

Placement Band - 1956 - 2017   Experience Band - 1968 - 2017



FortisBC Energy

Account #: 46400 - Transmission Plant - Other Structures

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	6,813,593	0	0.0000	1.0000	100.00
0.5	6,813,593	0	0.0000	1.0000	100.00
1.5	6,611,709	7,358	0.0011	0.9989	100.00
2.5	6,533,434	4,055	0.0006	0.9994	99.89
3.5	6,510,699	7,453	0.0011	0.9989	99.83
4.5	6,171,389	0	0.0000	1.0000	99.72
5.5	6,164,097	0	0.0000	1.0000	99.72
6.5	6,164,097	0	0.0000	1.0000	99.72
7.5	6,164,097	0	0.0000	1.0000	99.72
8.5	6,141,105	0	0.0000	1.0000	99.72
9.5	6,140,942	643	0.0001	0.9999	99.72
10.5	6,035,918	0	0.0000	1.0000	99.71
11.5	5,797,717	70	0.0000	1.0000	99.71
12.5	5,509,233	0	0.0000	1.0000	99.71
13.5	4,954,438	8,017	0.0016	0.9984	99.71
14.5	4,935,592	3,713	0.0008	0.9993	99.55
15.5	4,394,172	0	0.0000	1.0000	99.48
16.5	560,883	0	0.0000	1.0000	99.48
17.5	455,458	0	0.0000	1.0000	99.48
18.5	263,652	0	0.0000	1.0000	99.48
19.5	260,641	6,746	0.0259	0.9741	99.48
20.5	236,882	0	0.0000	1.0000	96.91
21.5	159,999	0	0.0000	1.0000	96.91
22.5	159,433	0	0.0000	1.0000	96.91
23.5	115,691	0	0.0000	1.0000	96.91
24.5	106,136	0	0.0000	1.0000	96.91
25.5	106,136	0	0.0000	1.0000	96.91
26.5	80,005	0	0.0000	1.0000	96.91
27.5	75,828	0	0.0000	1.0000	96.91
28.5	70,582	0	0.0000	1.0000	96.91
29.5	57,683	0	0.0000	1.0000	96.91
30.5	39,047	0	0.0000	1.0000	96.91
31.5	39,047	0	0.0000	1.0000	96.91
32.5	39,047	0	0.0000	1.0000	96.91
33.5	35,848	0	0.0000	1.0000	96.91
34.5	26,979	0	0.0000	1.0000	96.91
35.5	26,979	0	0.0000	1.0000	96.91
36.5	26,979	0	0.0000	1.0000	96.91
37.5	26,979	0	0.0000	1.0000	96.91
38.5	16,153	0	0.0000	1.0000	96.91
39.5	9,838	0	0.0000	1.0000	96.91
40.5	9,838	0	0.0000	1.0000	96.91
41.5	9,838	0	0.0000	1.0000	96.91
42.5	7,845	0	0.0000	1.0000	96.91
43.5	7,845	0	0.0000	1.0000	96.91

FortisBC Energy

Account #: 46400 - Transmission Plant - Other Structures

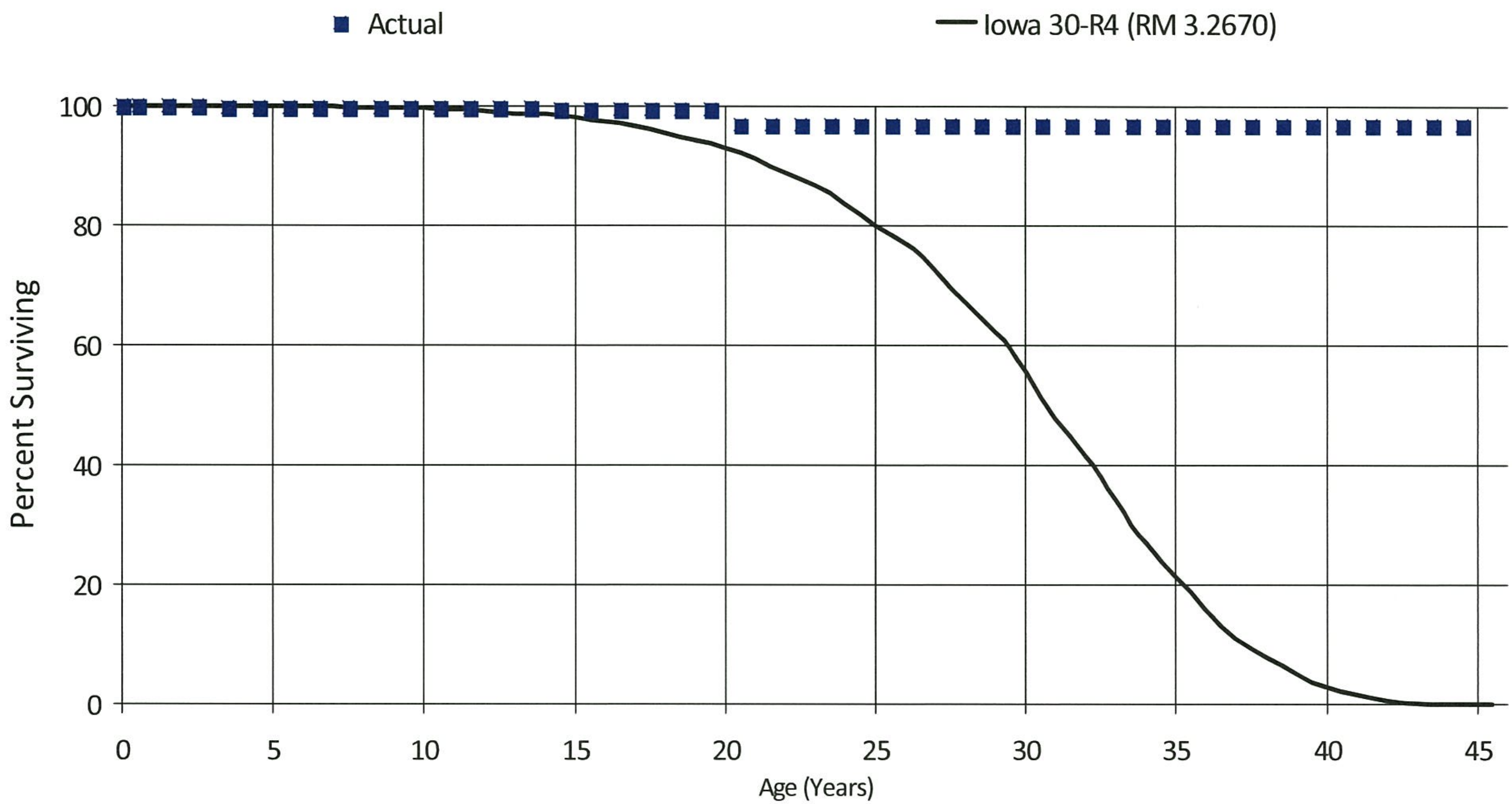
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	0	0	0.0000	0.0000	96.91

FortisBC Energy

Account #: 46400 - Transmission Plant - Other Structures

Actual and Smooth Survivor Curves

Placement Band - 1968 - 2017   Experience Band - 1970 - 2017



FortisBC Energy

Account #: 46500 - Transmission Plant - Transmission Pipeline

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,384,199,273	120,950	0.0001	0.9999	100.00
0.5	1,219,290,768	240,793	0.0002	0.9998	99.99
1.5	1,197,991,767	211,413	0.0002	0.9998	99.97
2.5	1,173,232,982	2,231,944	0.0019	0.9981	99.95
3.5	1,155,649,961	342,123	0.0003	0.9997	99.76
4.5	1,134,648,855	377,896	0.0003	0.9997	99.73
5.5	1,119,089,951	68,177	0.0001	0.9999	99.70
6.5	1,061,976,725	235,985	0.0002	0.9998	99.69
7.5	1,053,260,339	242,657	0.0002	0.9998	99.67
8.5	1,043,809,851	523,204	0.0005	0.9995	99.65
9.5	1,031,350,505	193,645	0.0002	0.9998	99.60
10.5	1,020,750,838	254,603	0.0003	0.9998	99.58
11.5	1,007,966,291	706,802	0.0007	0.9993	99.56
12.5	995,938,891	935,791	0.0009	0.9991	99.49
13.5	981,409,681	224,828	0.0002	0.9998	99.40
14.5	963,201,866	1,787,516	0.0019	0.9981	99.38
15.5	935,497,886	123,051	0.0001	0.9999	99.20
16.5	889,027,174	232,752	0.0003	0.9997	99.19
17.5	569,162,575	198,990	0.0004	0.9997	99.16
18.5	556,487,577	119,708	0.0002	0.9998	99.13
19.5	556,367,869	58,544	0.0001	0.9999	99.11
20.5	547,924,261	22,452	0.0000	1.0000	99.10
21.5	535,128,396	79,329	0.0002	0.9999	99.10
22.5	501,827,662	195,019	0.0004	0.9996	99.09
23.5	498,733,787	2,360,277	0.0047	0.9953	99.05
24.5	489,463,480	637,492	0.0013	0.9987	98.58
25.5	431,422,913	242,810	0.0006	0.9994	98.45
26.5	107,536,240	392,531	0.0037	0.9964	98.39
27.5	100,491,117	88,602	0.0009	0.9991	98.03
28.5	99,710,850	262,511	0.0026	0.9974	97.94
29.5	64,107,171	85,697	0.0013	0.9987	97.68
30.5	62,209,007	206,250	0.0033	0.9967	97.55
31.5	58,481,894	271,949	0.0047	0.9954	97.23
32.5	57,131,973	196,752	0.0034	0.9966	96.78
33.5	56,452,935	59,197	0.0011	0.9990	96.45
34.5	56,078,676	259,998	0.0046	0.9954	96.35
35.5	55,174,436	794,901	0.0144	0.9856	95.90
36.5	53,000,716	119,234	0.0023	0.9978	94.52
37.5	52,152,209	0	0.0000	1.0000	94.31
38.5	52,104,910	325,751	0.0063	0.9938	94.31
39.5	51,428,901	91,157	0.0018	0.9982	93.72
40.5	51,065,138	98,214	0.0019	0.9981	93.55
41.5	33,610,068	65,377	0.0020	0.9981	93.37
42.5	33,483,536	54,236	0.0016	0.9984	93.19
43.5	33,396,596	212,380	0.0064	0.9936	93.04

FortisBC Energy

Account #: 46500 - Transmission Plant - Transmission Pipeline

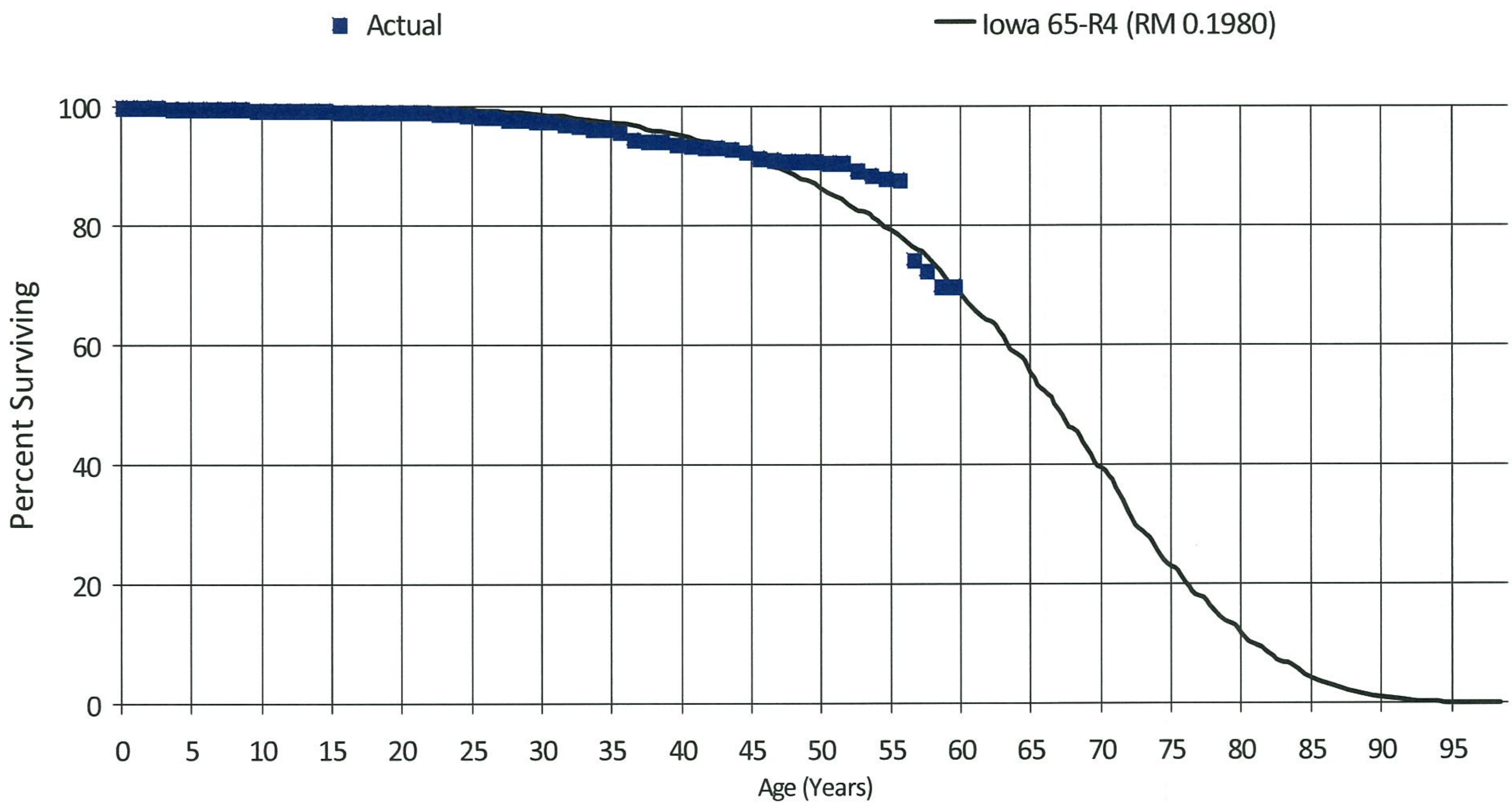
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	32,774,760	389,123	0.0119	0.9881	92.45
45.5	24,694,760	29,368	0.0012	0.9988	91.35
46.5	22,394,089	54,471	0.0024	0.9976	91.24
47.5	21,976,711	19,361	0.0009	0.9991	91.02
48.5	20,367,648	0	0.0000	1.0000	90.94
49.5	19,599,039	75,430	0.0039	0.9962	90.94
50.5	19,101,455	10,775	0.0006	0.9994	90.59
51.5	18,882,359	246,592	0.0131	0.9869	90.54
52.5	18,635,767	183,267	0.0098	0.9902	89.36
53.5	18,404,732	107,894	0.0059	0.9941	88.48
54.5	18,204,308	27,670	0.0015	0.9985	87.96
55.5	15,760,791	2,443,062	0.1550	0.8450	87.83
56.5	13,189,924	315,574	0.0239	0.9761	74.22
57.5	12,856,742	457,414	0.0356	0.9644	72.44
58.5	11,234,983	8,280	0.0007	0.9993	69.86
59.5	14,547	2,000	0.1375	0.8625	69.81

FortisBC Energy

Account #: 46500 - Transmission Plant - Transmission Pipeline

Actual and Smooth Survivor Curves

Placement Band - 1957 - 2017   Experience Band - 1962 - 2017



FortisBC Energy

Account #: 46511 - Transmission Plant - Intermediate Pipe - Whistler

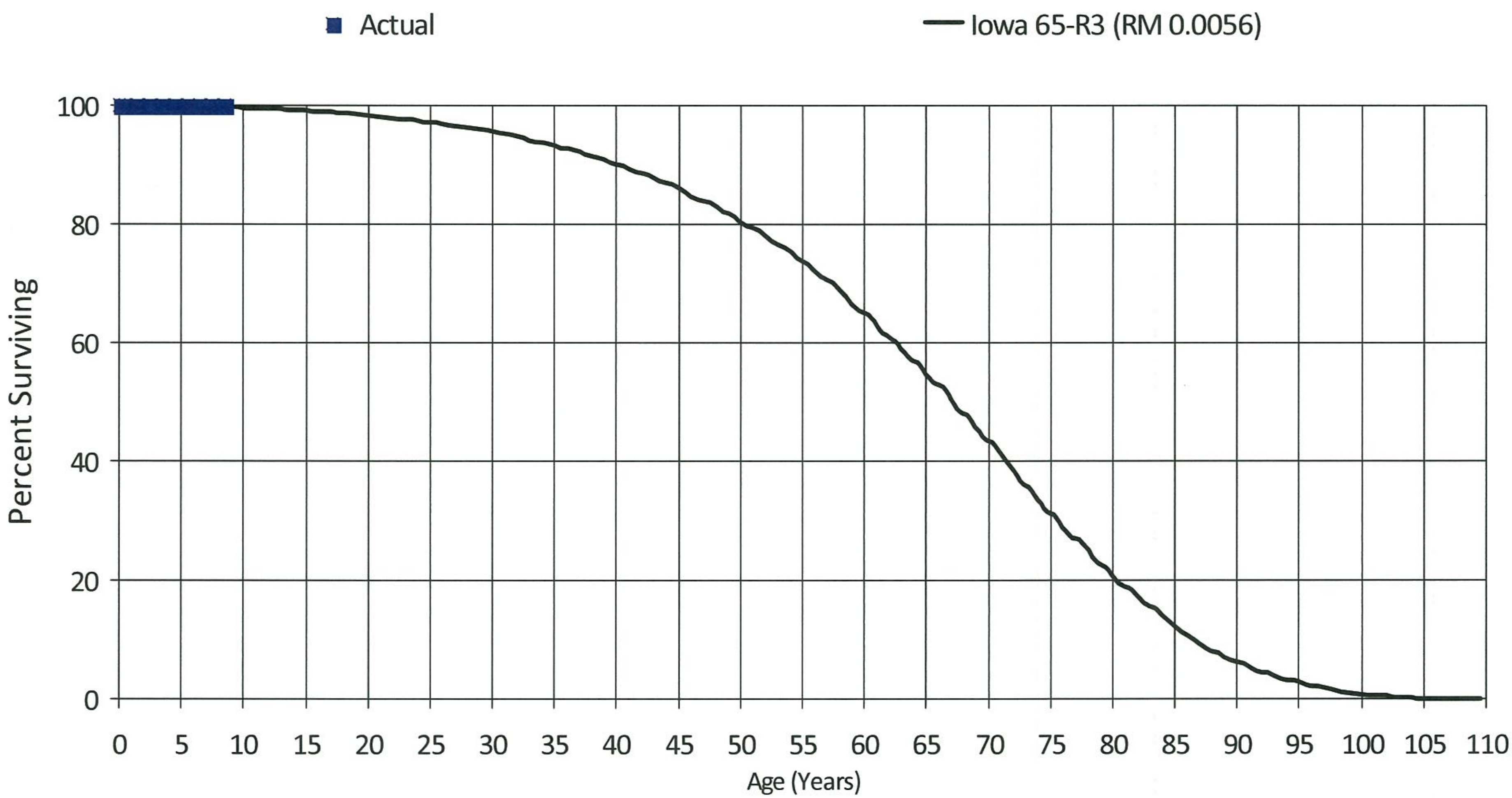
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	42,295,869	0	0.0000	1.0000	100.00
0.5	42,291,140	0	0.0000	1.0000	100.00
1.5	42,291,140	0	0.0000	1.0000	100.00
2.5	42,287,556	0	0.0000	1.0000	100.00
3.5	42,172,895	0	0.0000	1.0000	100.00
4.5	42,172,895	0	0.0000	1.0000	100.00
5.5	42,172,895	0	0.0000	1.0000	100.00
6.5	42,172,895	0	0.0000	1.0000	100.00
7.5	42,039,067	0	0.0000	1.0000	100.00
8.5	8,227	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 46511 - Transmission Plant - Intermediate Pipe - Whistler

Actual and Smooth Survivor Curves

Placement Band - 2008 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 46600 - Transmission Plant - Compressor Equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	196,504,049	35	0.0000	1.0000	100.00
0.5	189,135,556	556	0.0000	1.0000	100.00
1.5	182,468,197	758	0.0000	1.0000	100.00
2.5	178,950,602	2,978	0.0000	1.0000	100.00
3.5	178,125,563	1,513	0.0000	1.0000	100.00
4.5	176,703,079	16,949	0.0001	0.9999	100.00
5.5	173,778,135	23,569	0.0001	0.9999	99.99
6.5	169,923,106	206,181	0.0012	0.9988	99.98
7.5	169,512,411	260,667	0.0015	0.9985	99.86
8.5	164,561,921	62,334	0.0004	0.9996	99.71
9.5	161,183,739	305,855	0.0019	0.9981	99.67
10.5	142,463,222	101,825	0.0007	0.9993	99.48
11.5	141,921,487	11,150	0.0001	0.9999	99.41
12.5	140,042,656	139,310	0.0010	0.9990	99.40
13.5	137,565,851	6,869	0.0001	1.0000	99.30
14.5	136,860,244	37,088	0.0003	0.9997	99.30
15.5	130,335,369	255,037	0.0020	0.9980	99.27
16.5	124,446,161	677,697	0.0055	0.9946	99.08
17.5	73,105,072	285,588	0.0039	0.9961	98.54
18.5	65,778,663	1,223,034	0.0186	0.9814	98.15
19.5	58,446,501	135,051	0.0023	0.9977	96.33
20.5	54,839,303	678,340	0.0124	0.9876	96.11
21.5	52,153,827	510	0.0000	1.0000	94.92
22.5	47,316,384	160,085	0.0034	0.9966	94.92
23.5	27,928,176	9,084	0.0003	0.9997	94.60
24.5	22,834,209	500,374	0.0219	0.9781	94.57
25.5	19,553,973	501,436	0.0256	0.9744	92.50
26.5	2,661,341	655	0.0003	0.9998	90.13
27.5	2,630,212	4,049	0.0015	0.9985	90.11
28.5	2,606,081	22,073	0.0085	0.9915	89.97
29.5	2,570,502	0	0.0000	1.0000	89.21
30.5	2,482,907	79,374	0.0320	0.9680	89.21
31.5	2,395,924	29,977	0.0125	0.9875	86.36
32.5	2,364,659	0	0.0000	1.0000	85.28
33.5	2,361,184	0	0.0000	1.0000	85.28
34.5	2,330,142	0	0.0000	1.0000	85.28
35.5	2,330,142	0	0.0000	1.0000	85.28
36.5	2,327,132	32,582	0.0140	0.9860	85.28
37.5	2,294,550	0	0.0000	1.0000	84.09
38.5	2,291,709	0	0.0000	1.0000	84.09
39.5	1,513,636	0	0.0000	1.0000	84.09
40.5	1,464,608	0	0.0000	1.0000	84.09
41.5	1,452,220	0	0.0000	1.0000	84.09
42.5	1,449,467	0	0.0000	1.0000	84.09
43.5	1,161,436	0	0.0000	1.0000	84.09

FortisBC Energy

Account #: 46600 - Transmission Plant - Compressor Equipment

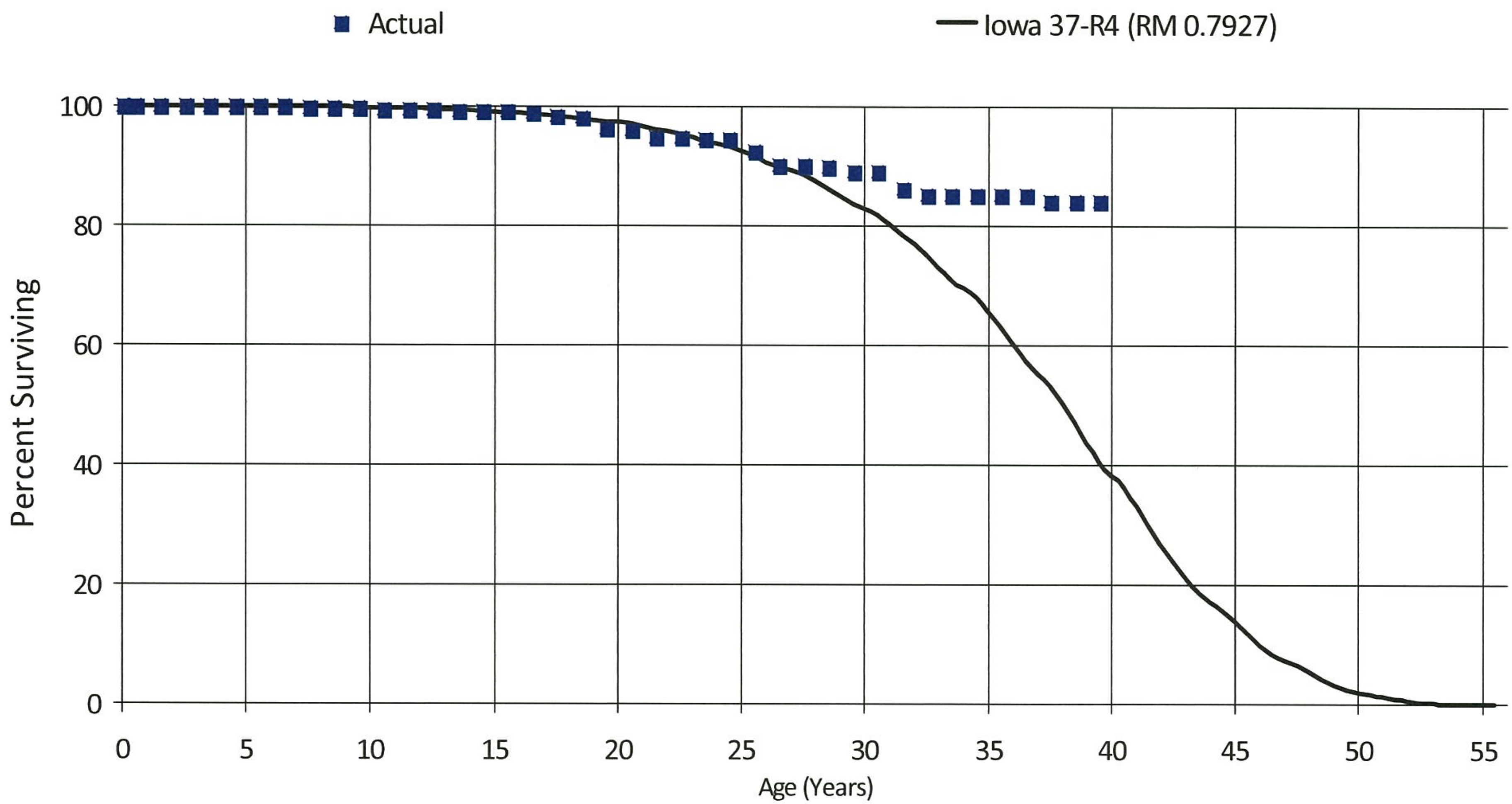
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	0	0	0.0000	0.0000	84.09

FortisBC Energy

Account #: 46600 - Transmission Plant - Compressor Equipment

Actual and Smooth Survivor Curves

Placement Band - 1965 - 2017   Experience Band - 1973 - 2017



FortisBC Energy

ount #: 46700 - Transmission Plant - Measuring and Regulating Equipment - Mt. Ha

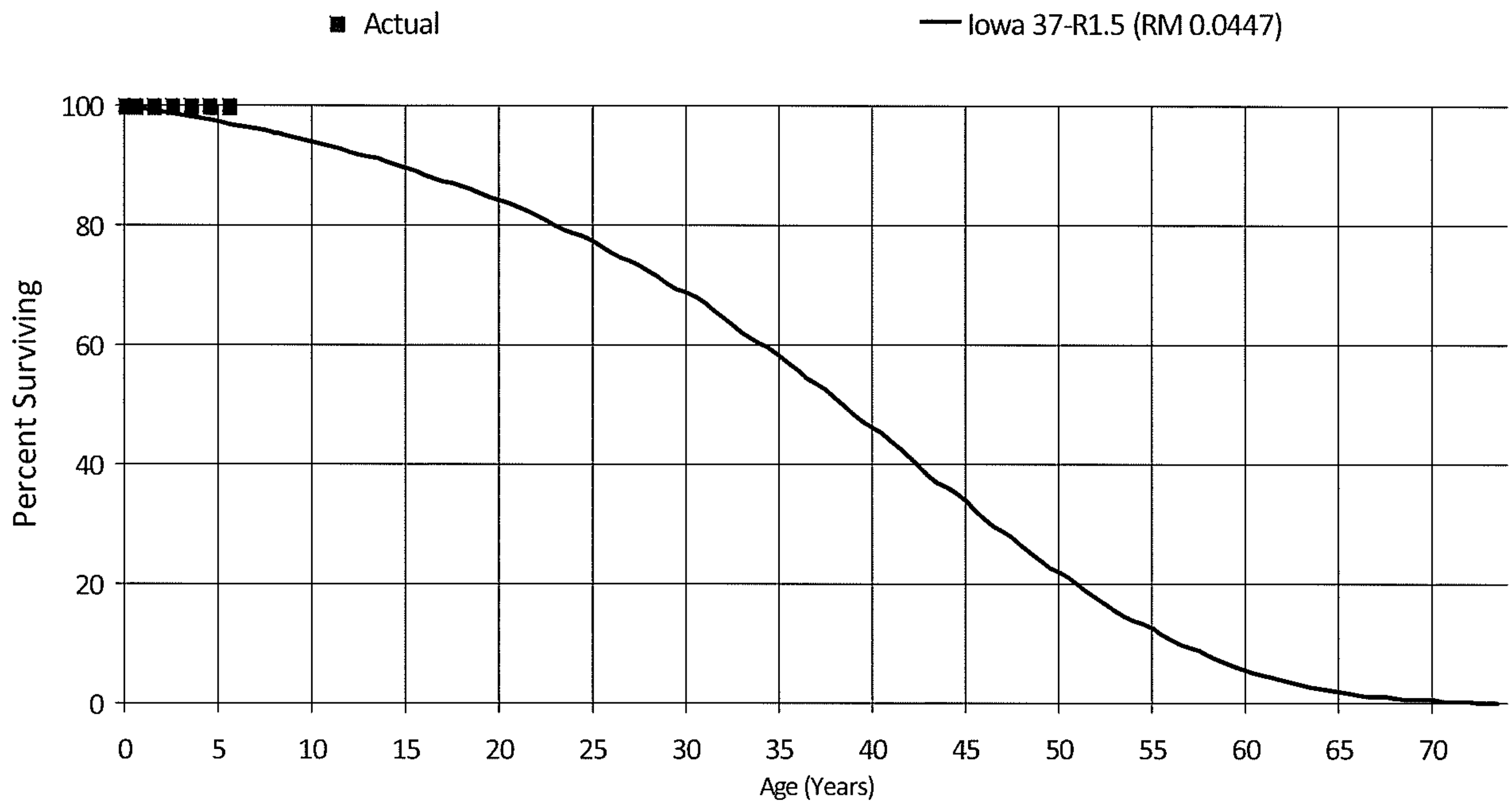
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	5,340,973	0	0.0000	1.0000	100.00
0.5	5,340,973	0	0.0000	1.0000	100.00
1.5	5,340,973	0	0.0000	1.0000	100.00
2.5	5,340,973	0	0.0000	1.0000	100.00
3.5	5,340,973	0	0.0000	1.0000	100.00
4.5	5,340,973	0	0.0000	1.0000	100.00
5.5	5,340,973	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 46700 - Transmission Plant - Measuring and Regulating Equipment - Mt. Hayes

Actual and Smooth Survivor Curves

Placement Band - 2011 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 46710 - Transmission Plant - Measuring and Regulating Equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	69,480,565	178,113	0.0026	0.9974	100.00
0.5	66,372,577	12,133	0.0002	0.9998	99.74
1.5	64,557,476	29,770	0.0005	0.9995	99.72
2.5	57,404,343	68,444	0.0012	0.9988	99.67
3.5	56,067,496	109,969	0.0020	0.9980	99.55
4.5	53,517,798	405,247	0.0076	0.9924	99.35
5.5	49,647,293	321,108	0.0065	0.9935	98.60
6.5	47,927,118	272,673	0.0057	0.9943	97.96
7.5	47,096,513	219,247	0.0047	0.9953	97.40
8.5	46,208,924	151,312	0.0033	0.9967	96.95
9.5	44,624,431	275,322	0.0062	0.9938	96.63
10.5	43,326,083	421,211	0.0097	0.9903	96.03
11.5	40,825,278	1,035,584	0.0254	0.9746	95.10
12.5	39,346,805	307,634	0.0078	0.9922	92.69
13.5	37,967,896	98,887	0.0026	0.9974	91.97
14.5	33,670,456	125,050	0.0037	0.9963	91.73
15.5	31,205,850	1,151,222	0.0369	0.9631	91.39
16.5	29,062,406	143,250	0.0049	0.9951	88.02
17.5	24,943,357	266,891	0.0107	0.9893	87.59
18.5	22,826,586	965,986	0.0423	0.9577	86.65
19.5	20,841,613	249,863	0.0120	0.9880	82.98
20.5	17,582,007	111,890	0.0064	0.9936	81.99
21.5	16,498,373	58,490	0.0036	0.9965	81.47
22.5	15,113,430	79,172	0.0052	0.9948	81.18
23.5	14,059,317	133,595	0.0095	0.9905	80.75
24.5	12,435,952	8,317	0.0007	0.9993	79.98
25.5	10,747,866	116,173	0.0108	0.9892	79.93
26.5	1,715,523	1,249	0.0007	0.9993	79.07
27.5	1,714,274	7,442	0.0043	0.9957	79.01
28.5	1,649,670	3,232	0.0020	0.9980	78.67
29.5	529,882	21,090	0.0398	0.9602	78.52
30.5	497,173	44,228	0.0890	0.9110	75.39
31.5	415,135	800	0.0019	0.9981	68.68
32.5	306,906	0	0.0000	1.0000	68.55
33.5	278,853	0	0.0000	1.0000	68.55
34.5	278,853	4,450	0.0160	0.9840	68.55
35.5	259,214	37,550	0.1449	0.8551	67.46
36.5	219,830	2,124	0.0097	0.9903	57.69
37.5	217,706	0	0.0000	1.0000	57.13
38.5	217,706	0	0.0000	1.0000	57.13
39.5	214,218	0	0.0000	1.0000	57.13
40.5	213,179	670	0.0031	0.9969	57.13
41.5	212,509	0	0.0000	1.0000	56.95
42.5	211,511	17,501	0.0827	0.9173	56.95
43.5	177,419	5,000	0.0282	0.9718	52.24

FortisBC Energy

Account #: 46710 - Transmission Plant - Measuring and Regulating Equipment

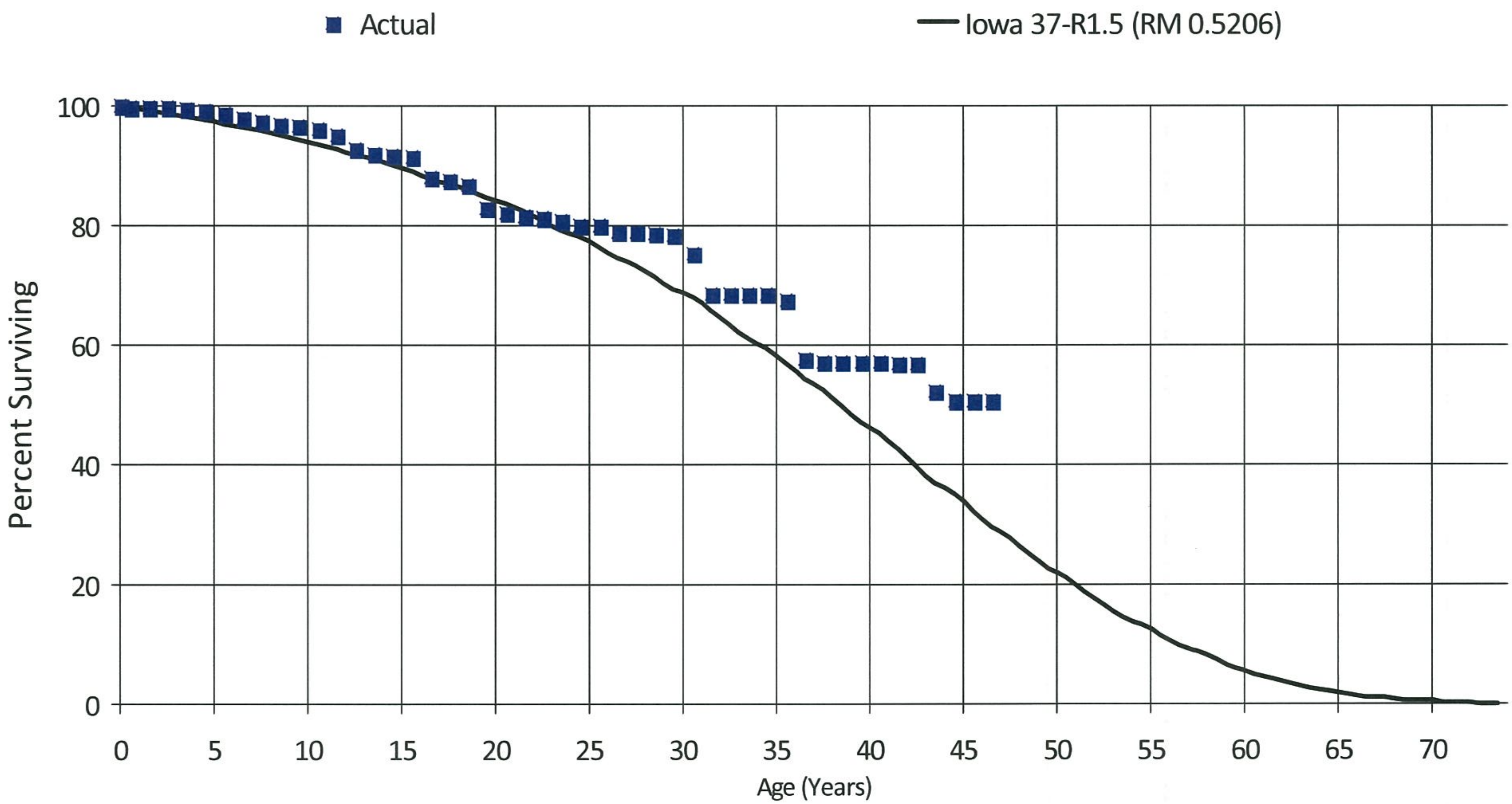
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	172,419	0	0.0000	1.0000	50.77
45.5	47,395	0	0.0000	1.0000	50.77
46.5	0	0	0.0000	0.0000	50.77

FortisBC Energy

Account #: 46710 - Transmission Plant - Measuring and Regulating Equipment

Actual and Smooth Survivor Curves

Placement Band - 1959 - 2017   Experience Band - 1968 - 2017



FortisBC Energy

Account #: 46720 - Transmission Plant - Telemetry Equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	22,485,986	12,073	0.0005	0.9995	100.00
0.5	22,309,037	45,109	0.0020	0.9980	99.95
1.5	21,498,086	978,712	0.0455	0.9545	99.75
2.5	16,957,683	83,362	0.0049	0.9951	95.21
3.5	15,974,069	53,988	0.0034	0.9966	94.74
4.5	14,490,850	56,162	0.0039	0.9961	94.42
5.5	13,767,237	185,424	0.0135	0.9865	94.05
6.5	10,315,419	1,223,566	0.1186	0.8814	92.78
7.5	8,974,186	118,502	0.0132	0.9868	81.77
8.5	8,719,941	95,520	0.0110	0.9891	80.69
9.5	8,447,591	235,495	0.0279	0.9721	79.81
10.5	8,106,629	41,519	0.0051	0.9949	77.58
11.5	6,925,986	71,345	0.0103	0.9897	77.18
12.5	6,832,263	968,173	0.1417	0.8583	76.39
13.5	5,424,770	119,054	0.0220	0.9781	65.56
14.5	5,205,365	102,444	0.0197	0.9803	64.12
15.5	4,968,445	54,904	0.0111	0.9890	62.86
16.5	4,451,542	112,326	0.0252	0.9748	62.17
17.5	3,992,100	61,450	0.0154	0.9846	60.60
18.5	2,070,452	126,714	0.0612	0.9388	59.67
19.5	1,851,530	394,401	0.2130	0.7870	56.02
20.5	1,253,283	19,720	0.0157	0.9843	44.09
21.5	1,118,025	68,992	0.0617	0.9383	43.40
22.5	759,726	53,099	0.0699	0.9301	40.72
23.5	556,390	12,282	0.0221	0.9779	37.87
24.5	421,476	5,731	0.0136	0.9864	37.03
25.5	323,695	30,770	0.0951	0.9049	36.53
26.5	213,235	0	0.0000	1.0000	33.06
27.5	213,235	0	0.0000	1.0000	33.06
28.5	212,275	61,082	0.2878	0.7123	33.06
29.5	143,399	0	0.0000	1.0000	23.55
30.5	135,399	0	0.0000	1.0000	23.55
31.5	134,873	600	0.0045	0.9956	23.55
32.5	99,965	0	0.0000	1.0000	23.45
33.5	91,291	0	0.0000	1.0000	23.45
34.5	91,291	0	0.0000	1.0000	23.45
35.5	82,883	4,345	0.0524	0.9476	23.45
36.5	76,884	0	0.0000	1.0000	22.22
37.5	49,049	0	0.0000	1.0000	22.22
38.5	47,609	11,208	0.2354	0.7646	22.22
39.5	29,685	0	0.0000	1.0000	16.99
40.5	29,685	0	0.0000	1.0000	16.99
41.5	22,750	0	0.0000	1.0000	16.99
42.5	22,750	0	0.0000	1.0000	16.99
43.5	20,658	0	0.0000	1.0000	16.99

FortisBC Energy

Account #: 46720 - Transmission Plant - Telemetry Equipment

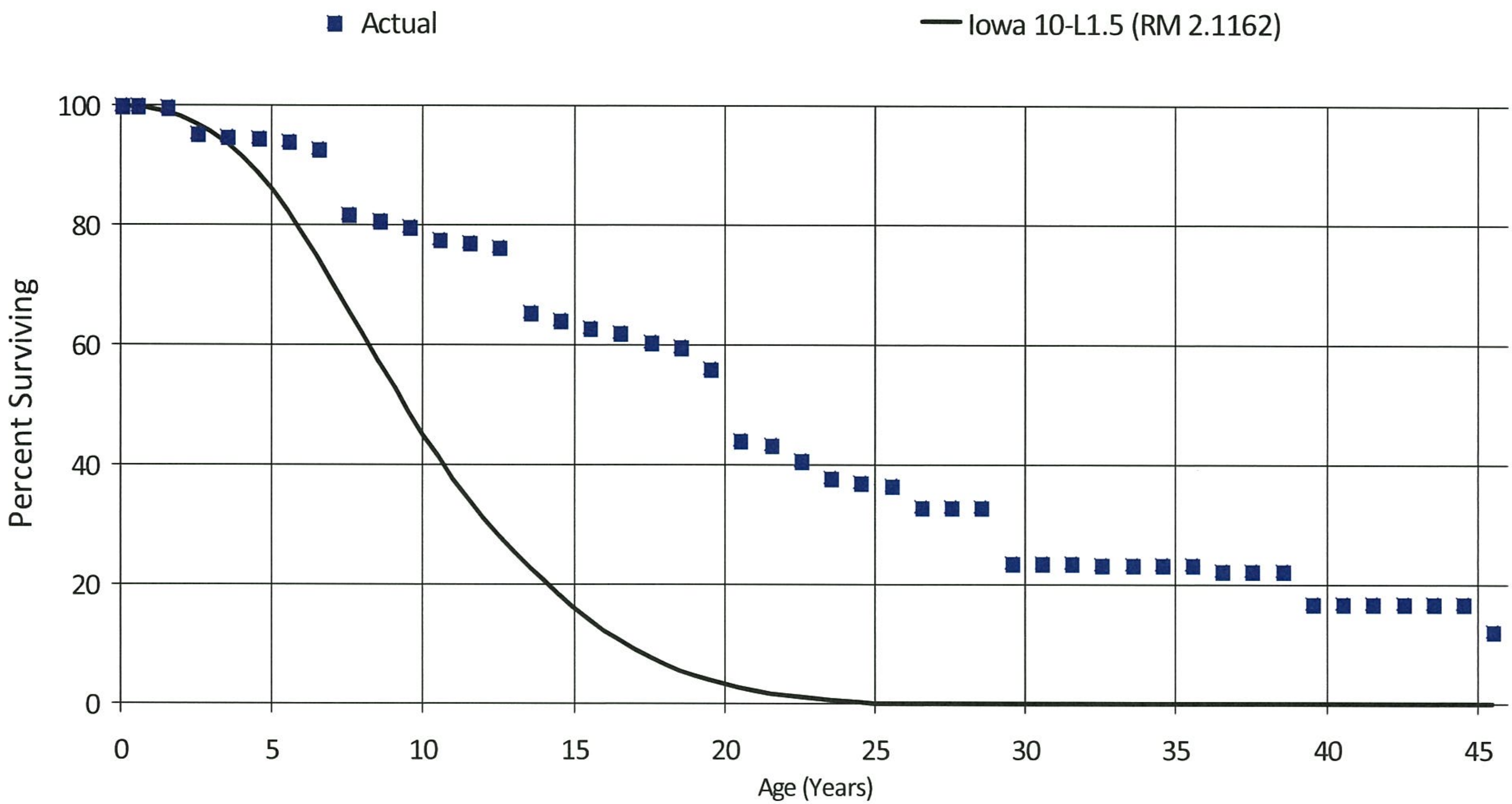
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	20,658	5,845	0.2830	0.7171	16.99
45.5	0	0	0.0000	0.0000	12.18

FortisBC Energy

Account #: 46720 - Transmission Plant - Telemetry Equipment

Actual and Smooth Survivor Curves

Placement Band - 1968 - 2017 Experience Band - 1973 - 2017



FortisBC Energy

count #: 46731 - Transmission Plant - Measuring and Regulating Equipment - Whist

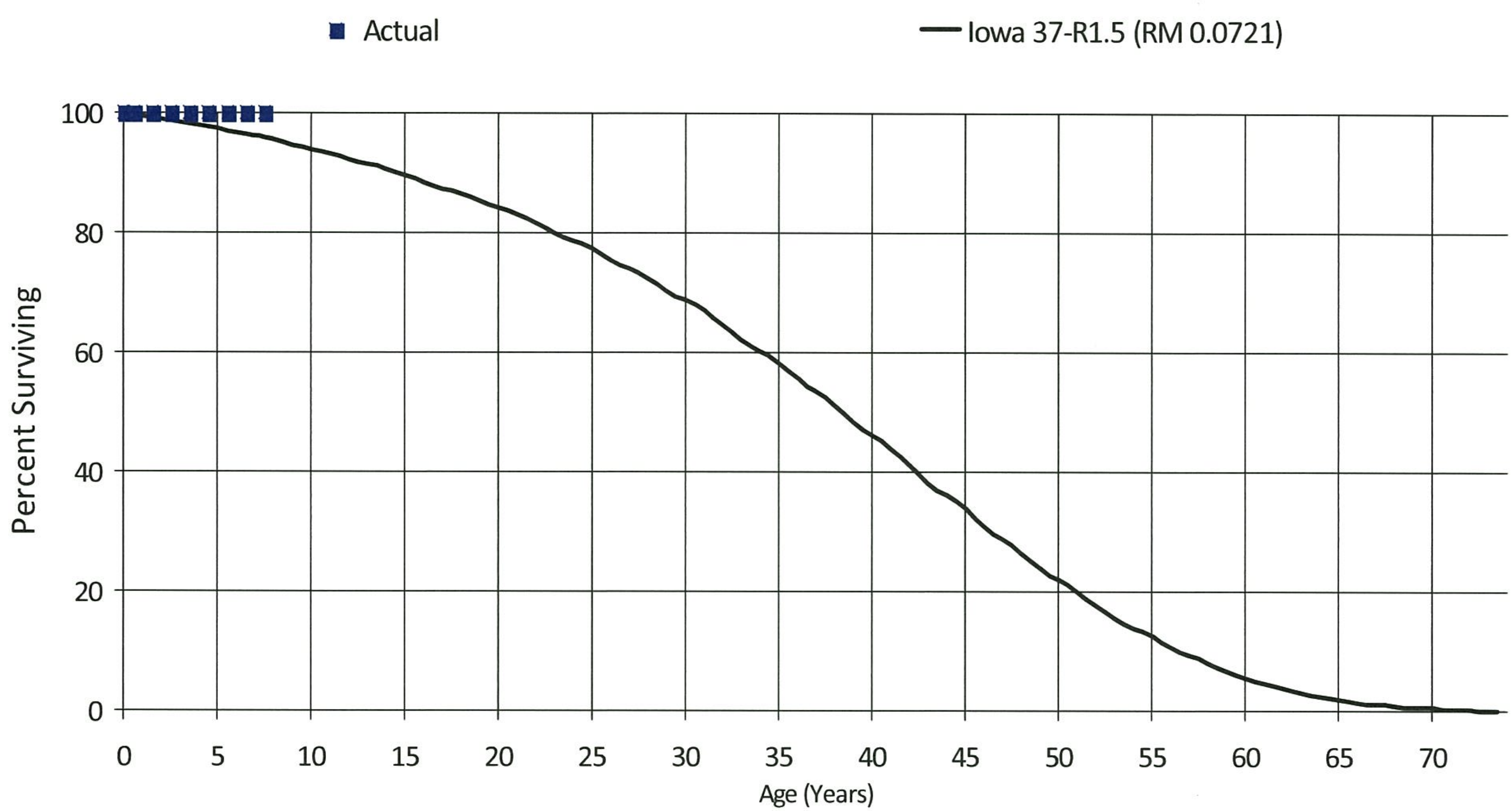
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	313,344	0	0.0000	1.0000	100.00
0.5	313,344	0	0.0000	1.0000	100.00
1.5	313,344	0	0.0000	1.0000	100.00
2.5	313,344	0	0.0000	1.0000	100.00
3.5	313,344	0	0.0000	1.0000	100.00
4.5	313,344	0	0.0000	1.0000	100.00
5.5	313,344	0	0.0000	1.0000	100.00
6.5	313,344	0	0.0000	1.0000	100.00
7.5	313,344	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 46731 - Transmission Plant - Measuring and Regulating Equipment - Whistler

Actual and Smooth Survivor Curves

Placement Band - 2009 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 46800 - Transmission Plant - Communications Equipment

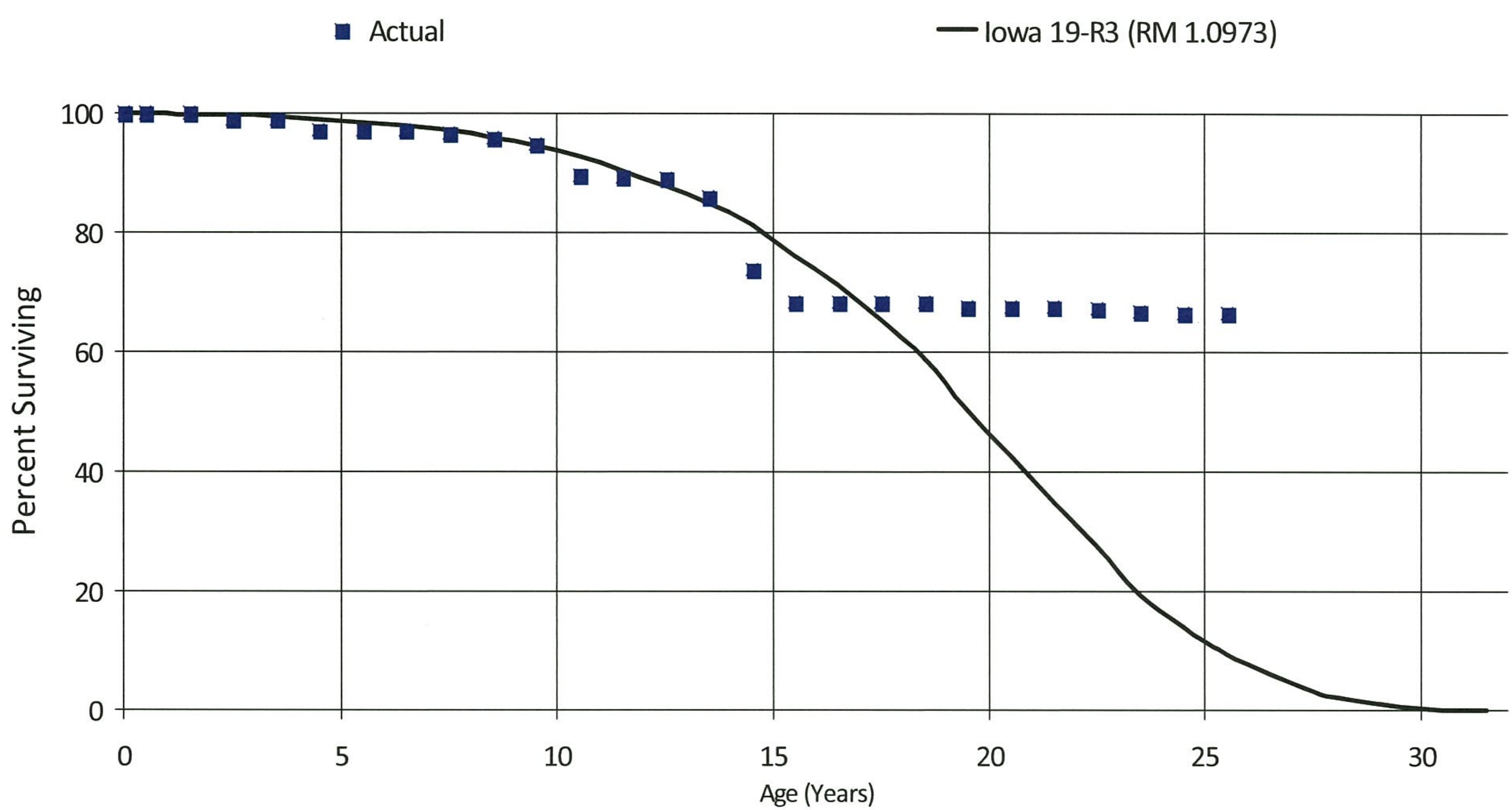
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	3,333,581	0	0.0000	1.0000	100.00
0.5	3,336,496	0	0.0000	1.0000	100.00
1.5	3,336,496	30,284	0.0091	0.9909	100.00
2.5	3,306,106	106	0.0000	1.0000	99.09
3.5	5,043,469	101,196	0.0201	0.9799	99.09
4.5	4,677,434	0	0.0000	1.0000	97.10
5.5	4,677,421	849	0.0002	0.9998	97.10
6.5	4,381,858	19,964	0.0046	0.9954	97.08
7.5	4,360,954	37,386	0.0086	0.9914	96.64
8.5	4,093,915	37,644	0.0092	0.9908	95.81
9.5	4,014,138	225,386	0.0562	0.9439	94.93
10.5	3,531,263	7,378	0.0021	0.9979	89.60
11.5	3,509,406	17,333	0.0049	0.9951	89.41
12.5	3,492,073	122,320	0.0350	0.9650	88.97
13.5	3,364,832	476,973	0.1418	0.8583	85.85
14.5	2,450,446	180,769	0.0738	0.9262	73.68
15.5	2,221,882	0	0.0000	1.0000	68.24
16.5	2,126,600	0	0.0000	1.0000	68.24
17.5	2,124,192	0	0.0000	1.0000	68.24
18.5	2,121,179	22,940	0.0108	0.9892	68.24
19.5	2,055,159	417	0.0002	0.9998	67.50
20.5	2,016,481	0	0.0000	1.0000	67.49
21.5	2,012,674	10,144	0.0050	0.9950	67.49
22.5	1,982,137	12,206	0.0062	0.9938	67.15
23.5	1,963,378	5,319	0.0027	0.9973	66.74
24.5	1,958,059	0	0.0000	1.0000	66.56
25.5	1,958,059	0	0.0000	1.0000	66.56

FortisBC Energy

Account #: 46800 - Transmission Plant - Communications Equipment

Actual and Smooth Survivor Curves

Placement Band - 1991 - 2017 Experience Band - 1995 - 2017



FortisBC Energy

Account #: 47200 - Distribution Plant - Structures

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	27,850,402	91,687	0.0033	0.9967	100.00
0.5	26,848,907	75,898	0.0028	0.9972	99.67
1.5	25,890,736	200,569	0.0078	0.9923	99.39
2.5	24,313,217	117,864	0.0049	0.9952	98.62
3.5	23,743,741	113,207	0.0048	0.9952	98.14
4.5	22,706,144	173,877	0.0077	0.9923	97.67
5.5	21,535,437	22,826	0.0011	0.9989	96.92
6.5	19,475,338	24,883	0.0013	0.9987	96.82
7.5	18,973,747	59,802	0.0032	0.9969	96.70
8.5	18,363,352	81,760	0.0045	0.9956	96.40
9.5	17,225,301	132,675	0.0077	0.9923	95.97
10.5	16,177,176	53,744	0.0033	0.9967	95.23
11.5	13,662,880	82,419	0.0060	0.9940	94.91
12.5	11,375,973	41,035	0.0036	0.9964	94.34
13.5	10,112,680	28,684	0.0028	0.9972	94.00
14.5	9,755,301	700,750	0.0718	0.9282	93.73
15.5	8,832,203	111,094	0.0126	0.9874	87.00
16.5	8,136,101	13,759	0.0017	0.9983	85.91
17.5	7,588,079	18,707	0.0025	0.9975	85.76
18.5	7,122,752	7,305	0.0010	0.9990	85.55
19.5	6,647,597	33,860	0.0051	0.9949	85.46
20.5	5,681,813	18,346	0.0032	0.9968	85.03
21.5	4,658,099	14,988	0.0032	0.9968	84.76
22.5	3,722,935	5,722	0.0015	0.9985	84.49
23.5	2,960,615	68,201	0.0230	0.9770	84.36
24.5	2,663,612	63,894	0.0240	0.9760	82.42
25.5	1,935,564	8,894	0.0046	0.9954	80.44
26.5	921,258	9,489	0.0103	0.9897	80.07
27.5	867,706	85,832	0.0989	0.9011	79.25
28.5	755,023	6,623	0.0088	0.9912	71.41
29.5	730,964	7,625	0.0104	0.9896	70.78
30.5	577,556	6,871	0.0119	0.9881	70.04
31.5	456,610	5,674	0.0124	0.9876	69.21
32.5	439,149	38,266	0.0871	0.9129	68.35
33.5	374,174	12,424	0.0332	0.9668	62.39
34.5	320,678	7,637	0.0238	0.9762	60.32
35.5	304,707	5,185	0.0170	0.9830	58.88
36.5	223,091	23,097	0.1035	0.8965	57.88
37.5	192,798	23,397	0.1214	0.8787	51.89
38.5	168,367	11,575	0.0688	0.9313	45.59
39.5	156,776	10,276	0.0656	0.9345	42.46
40.5	146,501	365	0.0025	0.9975	39.68
41.5	144,313	9,320	0.0646	0.9354	39.58
42.5	128,254	5,444	0.0425	0.9576	37.02
43.5	118,755	3,313	0.0279	0.9721	35.45

FortisBC Energy

Account #: 47200 - Distribution Plant - Structures

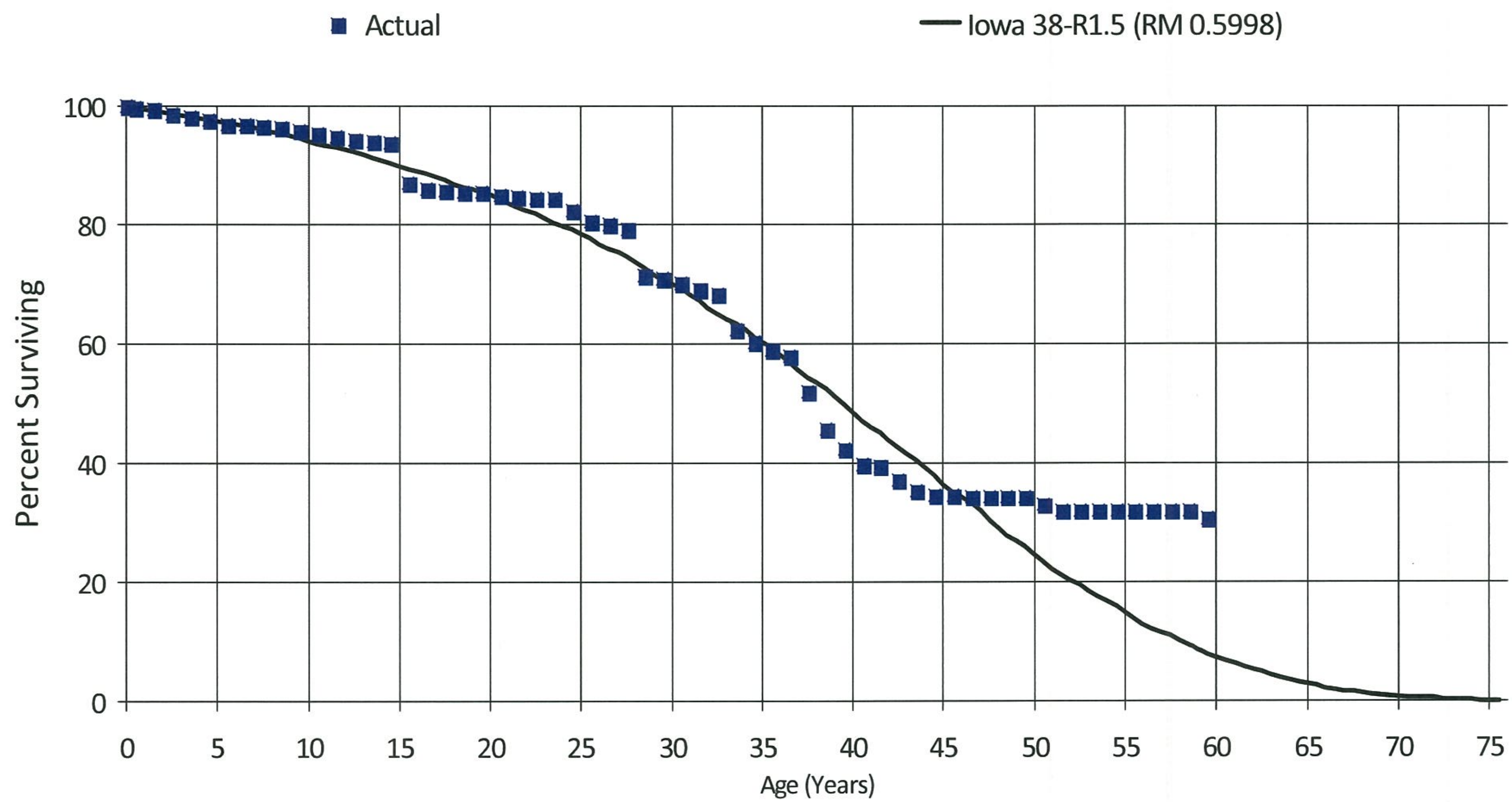
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	101,462	0	0.0000	1.0000	34.46
45.5	97,408	728	0.0075	0.9925	34.46
46.5	95,996	0	0.0000	1.0000	34.20
47.5	80,944	0	0.0000	1.0000	34.20
48.5	79,110	0	0.0000	1.0000	34.20
49.5	63,621	2,024	0.0318	0.9682	34.20
50.5	61,598	2,101	0.0341	0.9659	33.11
51.5	59,496	0	0.0000	1.0000	31.98
52.5	58,937	0	0.0000	1.0000	31.98
53.5	58,937	0	0.0000	1.0000	31.98
54.5	58,937	0	0.0000	1.0000	31.98
55.5	43,528	0	0.0000	1.0000	31.98
56.5	21,818	0	0.0000	1.0000	31.98
57.5	21,818	0	0.0000	1.0000	31.98
58.5	21,818	943	0.0432	0.9568	31.98
59.5	0	0	0.0000	0.0000	30.60

FortisBC Energy

Account #: 47200 - Distribution Plant - Structures

Actual and Smooth Survivor Curves

Placement Band - 1957 - 2017 Experience Band - 1959 - 2017



FortisBC Energy

Account #: 47220 - Bio Gas - Structures and Improvements

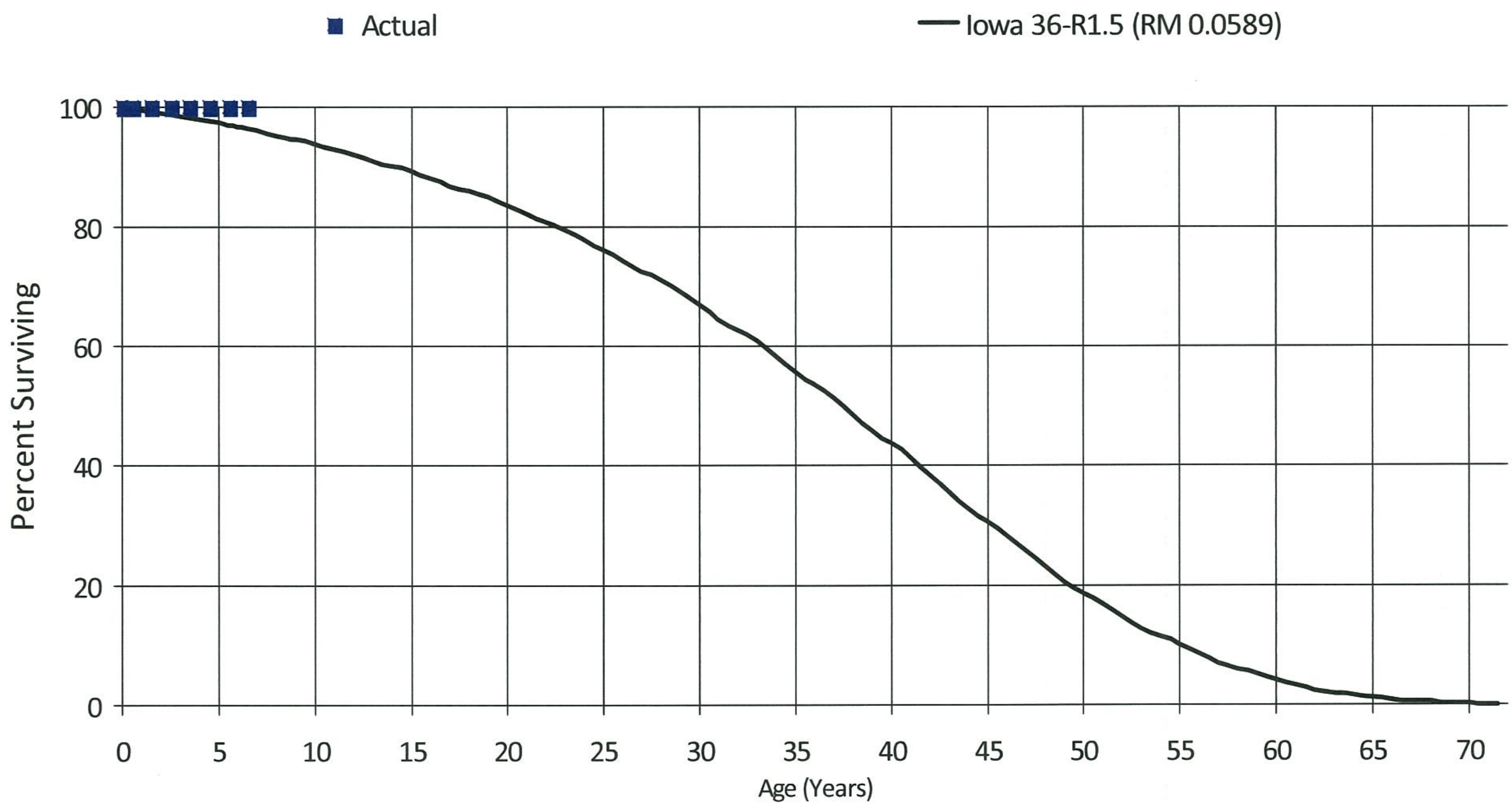
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	654,898	0	0.0000	1.0000	100.00
0.5	654,898	0	0.0000	1.0000	100.00
1.5	622,023	0	0.0000	1.0000	100.00
2.5	462,387	0	0.0000	1.0000	100.00
3.5	184,972	0	0.0000	1.0000	100.00
4.5	136,986	0	0.0000	1.0000	100.00
5.5	136,986	0	0.0000	1.0000	100.00
6.5	136,986	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 47220 - Bio Gas - Structures and Improvements

Actual and Smooth Survivor Curves

Placement Band - 2010 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 47300 - Distribution Plant - Services

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,265,070,049	12,126,777	0.0096	0.9904	100.00
0.5	1,198,674,982	2,427,961	0.0020	0.9980	99.04
1.5	1,154,254,499	2,793,510	0.0024	0.9976	98.84
2.5	1,108,135,553	2,495,908	0.0023	0.9978	98.60
3.5	1,060,718,463	2,487,541	0.0024	0.9977	98.38
4.5	1,014,746,452	3,512,103	0.0035	0.9965	98.15
5.5	968,791,236	2,764,480	0.0029	0.9972	97.81
6.5	929,632,313	2,614,819	0.0028	0.9972	97.53
7.5	892,295,400	8,745,025	0.0098	0.9902	97.26
8.5	850,551,213	2,434,732	0.0029	0.9971	96.31
9.5	802,903,492	3,127,582	0.0039	0.9961	96.03
10.5	756,725,277	3,274,378	0.0043	0.9957	95.66
11.5	717,756,510	3,301,696	0.0046	0.9954	95.25
12.5	680,264,732	2,170,805	0.0032	0.9968	94.81
13.5	650,046,261	3,268,597	0.0050	0.9950	94.51
14.5	622,050,239	3,150,450	0.0051	0.9949	94.03
15.5	595,030,227	3,226,018	0.0054	0.9946	93.55
16.5	570,066,152	3,922,020	0.0069	0.9931	93.04
17.5	537,779,122	4,366,954	0.0081	0.9919	92.40
18.5	508,353,466	4,637,637	0.0091	0.9909	91.65
19.5	474,823,642	3,161,195	0.0067	0.9933	90.81
20.5	437,863,256	3,505,483	0.0080	0.9920	90.21
21.5	398,061,615	3,390,874	0.0085	0.9915	89.49
22.5	357,453,905	3,340,619	0.0094	0.9907	88.73
23.5	316,533,534	4,415,784	0.0140	0.9861	87.90
24.5	271,631,664	2,353,114	0.0087	0.9913	86.67
25.5	231,425,640	1,890,794	0.0082	0.9918	85.92
26.5	204,808,093	2,097,454	0.0102	0.9898	85.22
27.5	50,601,920	373,315	0.0074	0.9926	84.35
28.5	46,160,655	372,740	0.0081	0.9919	83.73
29.5	42,908,498	388,455	0.0091	0.9910	83.05
30.5	37,236,130	302,478	0.0081	0.9919	82.30
31.5	34,702,395	244,897	0.0071	0.9929	81.63
32.5	29,032,128	174,893	0.0060	0.9940	81.05
33.5	25,724,080	148,554	0.0058	0.9942	80.56
34.5	22,167,502	161,329	0.0073	0.9927	80.10
35.5	19,191,050	147,275	0.0077	0.9923	79.52
36.5	16,084,114	150,624	0.0094	0.9906	78.91
37.5	13,937,699	164,817	0.0118	0.9882	78.17
38.5	12,380,122	168,371	0.0136	0.9864	77.25
39.5	10,779,711	172,091	0.0160	0.9840	76.20
40.5	9,327,365	108,561	0.0116	0.9884	74.98
41.5	7,833,384	49,090	0.0063	0.9937	74.11
42.5	6,822,796	36,878	0.0054	0.9946	73.65
43.5	5,781,095	31,267	0.0054	0.9946	73.25

FortisBC Energy

Account #: 47300 - Distribution Plant - Services

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	4,979,357	92,396	0.0186	0.9814	72.85
45.5	4,359,394	29,377	0.0067	0.9933	71.50
46.5	3,905,530	37,857	0.0097	0.9903	71.02
47.5	3,468,335	29,647	0.0086	0.9915	70.33
48.5	3,240,970	36,307	0.0112	0.9888	69.73
49.5	2,947,281	40,091	0.0136	0.9864	68.95
50.5	2,666,020	34,188	0.0128	0.9872	68.01
51.5	2,407,852	30,660	0.0127	0.9873	67.14
52.5	2,198,419	26,152	0.0119	0.9881	66.29
53.5	1,959,698	32,873	0.0168	0.9832	65.50
54.5	1,694,315	63,091	0.0372	0.9628	64.40
55.5	1,464,591	22,537	0.0154	0.9846	62.00
56.5	1,442,054	28,868	0.0200	0.9800	61.05
57.5	1,283,679	23,709	0.0185	0.9815	59.83
58.5	80,300	3,372	0.0420	0.9580	58.72
59.5	76,928	2,777	0.0361	0.9639	56.25
60.5	74,151	1,500	0.0202	0.9798	54.22
61.5	72,651	777	0.0107	0.9893	53.12
62.5	71,874	1,686	0.0235	0.9765	52.55
63.5	70,188	1,480	0.0211	0.9789	51.32
64.5	68,708	2,377	0.0346	0.9654	50.24
65.5	66,331	3,544	0.0534	0.9466	48.50
66.5	62,787	6,635	0.1057	0.8943	45.91
67.5	56,152	10,001	0.1781	0.8219	41.06
68.5	46,151	13,679	0.2964	0.7036	33.75
69.5	32,472	5,866	0.1807	0.8194	23.75
70.5	26,606	13,087	0.4919	0.5081	19.46
71.5	13,519	9,566	0.7076	0.2924	9.89
72.5	3,953	1,500	0.3795	0.6205	2.89
73.5	2,453	1,200	0.4892	0.5108	1.79
74.5	1,253	287	0.2291	0.7710	0.91
75.5	966	400	0.4141	0.5859	0.70
76.5	566	0	0.0000	1.0000	0.41
77.5	566	0	0.0000	1.0000	0.41
78.5	566	0	0.0000	1.0000	0.41
79.5	566	0	0.0000	1.0000	0.41
80.5	566	0	0.0000	1.0000	0.41
81.5	566	0	0.0000	1.0000	0.41
82.5	566	0	0.0000	1.0000	0.41
83.5	566	300	0.5300	0.4700	0.41
84.5	266	0	0.0000	1.0000	0.19
85.5	266	0	0.0000	1.0000	0.19
86.5	266	0	0.0000	1.0000	0.19
87.5	266	0	0.0000	1.0000	0.19
88.5	266	0	0.0000	1.0000	0.19

FortisBC Energy

Account #: 47300 - Distribution Plant - Services

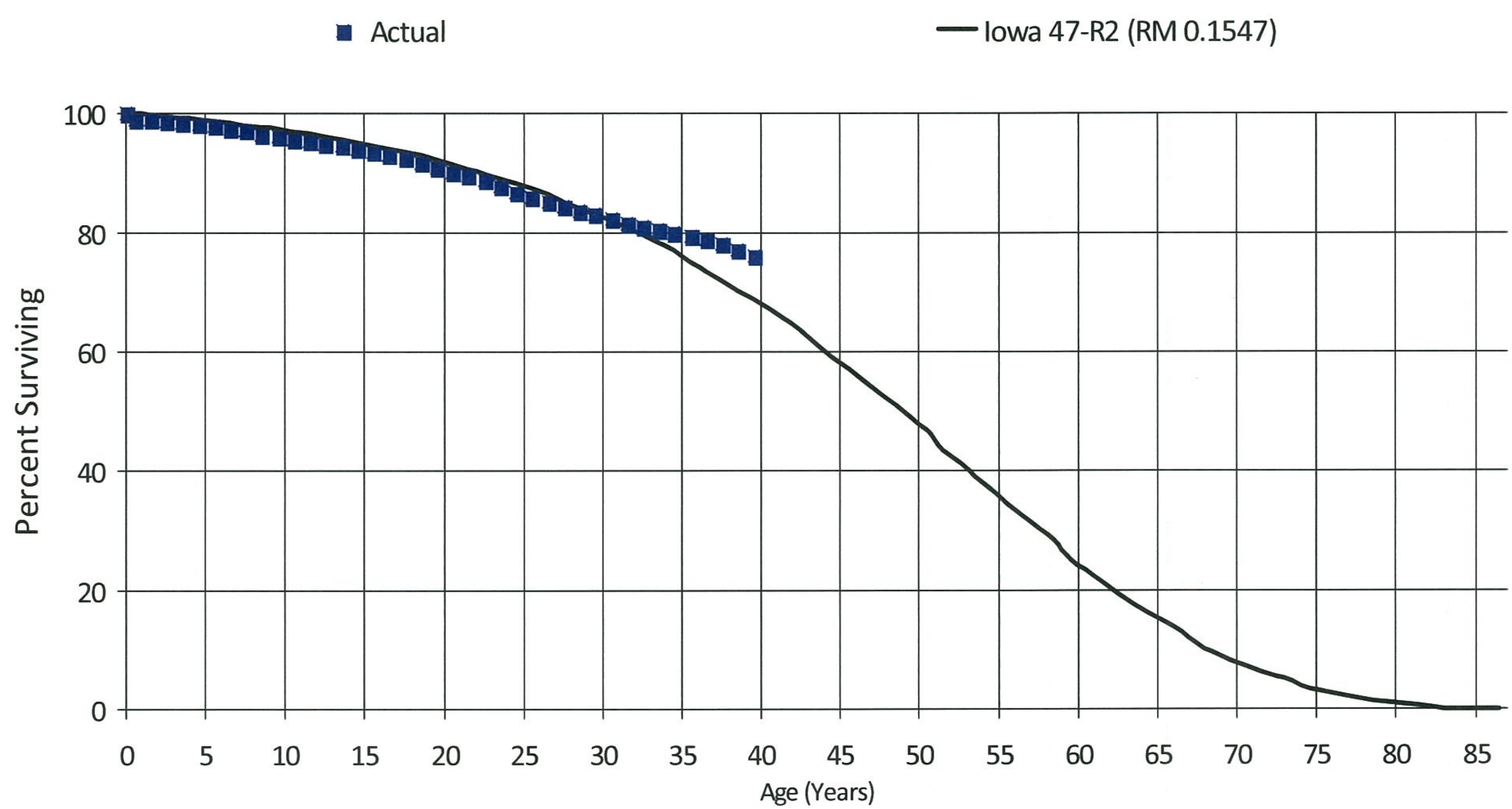
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
89.5	266	0	0.0000	1.0000	0.19
90.5	266	0	0.0000	1.0000	0.19
91.5	266	266	1.0000		0.19

FortisBC Energy

Account #: 47300 - Distribution Plant - Services

Actual and Smooth Survivor Curves

Placement Band - 1900 - 2017   Experience Band - 1963 - 2017



FortisBC Energy

Account #: 47410 - Bio Gas - Meters/Regulator Installations

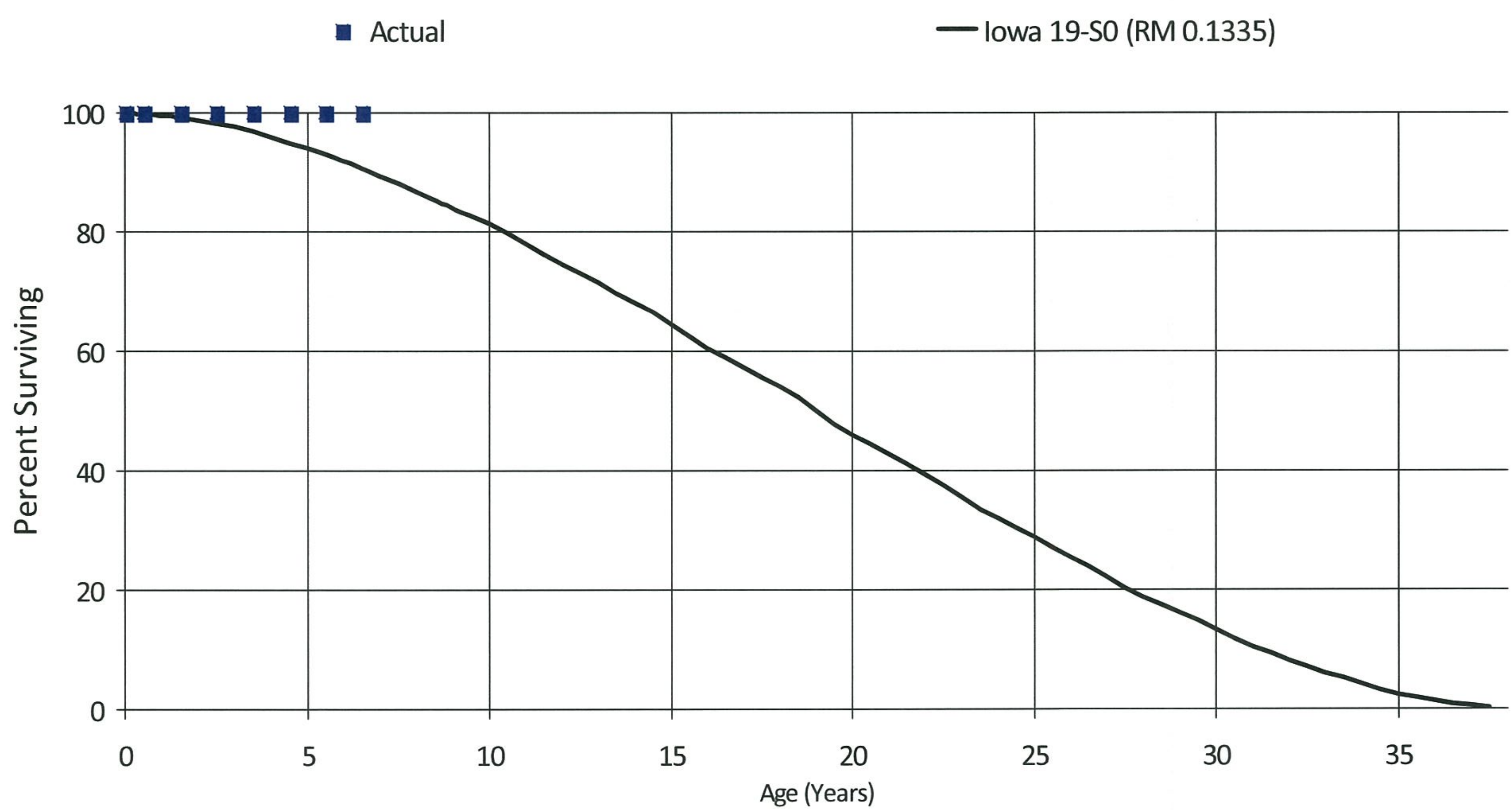
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	226,054	0	0.0000	1.0000	100.00
0.5	226,054	0	0.0000	1.0000	100.00
1.5	218,581	0	0.0000	1.0000	100.00
2.5	177,183	0	0.0000	1.0000	100.00
3.5	21,780	0	0.0000	1.0000	100.00
4.5	21,780	0	0.0000	1.0000	100.00
5.5	21,780	0	0.0000	1.0000	100.00
6.5	21,780	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 47410 - Bio Gas - Meters/Regulator Installations

Actual and Smooth Survivor Curves

Placement Band - 2010 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 47500 - Distribution Plant - Systems - Mains

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,473,699,109	574,233	0.0004	0.9996	100.00
0.5	1,432,896,748	4,648,764	0.0032	0.9968	99.96
1.5	1,395,497,662	1,612,310	0.0012	0.9988	99.64
2.5	1,351,016,543	1,079,004	0.0008	0.9992	99.52
3.5	1,316,339,486	1,125,497	0.0009	0.9991	99.44
4.5	1,279,916,815	1,509,553	0.0012	0.9988	99.35
5.5	1,252,753,230	1,431,709	0.0011	0.9989	99.23
6.5	1,227,180,600	2,681,723	0.0022	0.9978	99.12
7.5	1,200,361,863	2,021,799	0.0017	0.9983	98.90
8.5	1,162,396,190	902,797	0.0008	0.9992	98.73
9.5	1,121,904,594	2,494,731	0.0022	0.9978	98.65
10.5	1,082,384,553	1,833,060	0.0017	0.9983	98.43
11.5	1,047,382,279	1,656,724	0.0016	0.9984	98.26
12.5	1,017,481,308	1,059,160	0.0010	0.9990	98.10
13.5	989,768,414	1,534,651	0.0016	0.9985	98.00
14.5	957,385,860	1,426,189	0.0015	0.9985	97.85
15.5	928,671,485	1,817,699	0.0020	0.9980	97.70
16.5	892,665,926	1,910,386	0.0021	0.9979	97.51
17.5	858,590,550	3,003,792	0.0035	0.9965	97.30
18.5	814,966,578	3,366,069	0.0041	0.9959	96.96
19.5	772,379,928	1,078,879	0.0014	0.9986	96.56
20.5	727,854,167	833,946	0.0012	0.9989	96.42
21.5	683,369,205	1,050,116	0.0015	0.9985	96.31
22.5	631,884,922	1,304,143	0.0021	0.9979	96.16
23.5	581,324,210	2,295,247	0.0040	0.9961	95.96
24.5	535,336,151	966,569	0.0018	0.9982	95.58
25.5	455,578,480	608,661	0.0013	0.9987	95.41
26.5	402,252,220	864,229	0.0022	0.9979	95.28
27.5	72,205,950	386,932	0.0054	0.9946	95.08
28.5	69,029,546	292,274	0.0042	0.9958	94.57
29.5	66,501,565	241,420	0.0036	0.9964	94.17
30.5	61,782,466	245,834	0.0040	0.9960	93.83
31.5	58,610,262	867,808	0.0148	0.9852	93.46
32.5	54,437,424	80,825	0.0015	0.9985	92.08
33.5	49,910,013	112,244	0.0023	0.9978	91.94
34.5	40,608,744	108,886	0.0027	0.9973	91.73
35.5	34,479,433	43,016	0.0013	0.9988	91.48
36.5	30,894,760	61,621	0.0020	0.9980	91.37
37.5	27,716,645	81,129	0.0029	0.9971	91.19
38.5	24,833,731	45,913	0.0019	0.9982	90.92
39.5	23,049,589	164,004	0.0071	0.9929	90.75
40.5	21,084,394	51,889	0.0025	0.9975	90.10
41.5	19,115,262	41,068	0.0022	0.9979	89.88
42.5	17,795,856	28,316	0.0016	0.9984	89.69
43.5	15,805,743	10,320	0.0007	0.9994	89.55

FortisBC Energy

Account #: 47500 - Distribution Plant - Systems - Mains

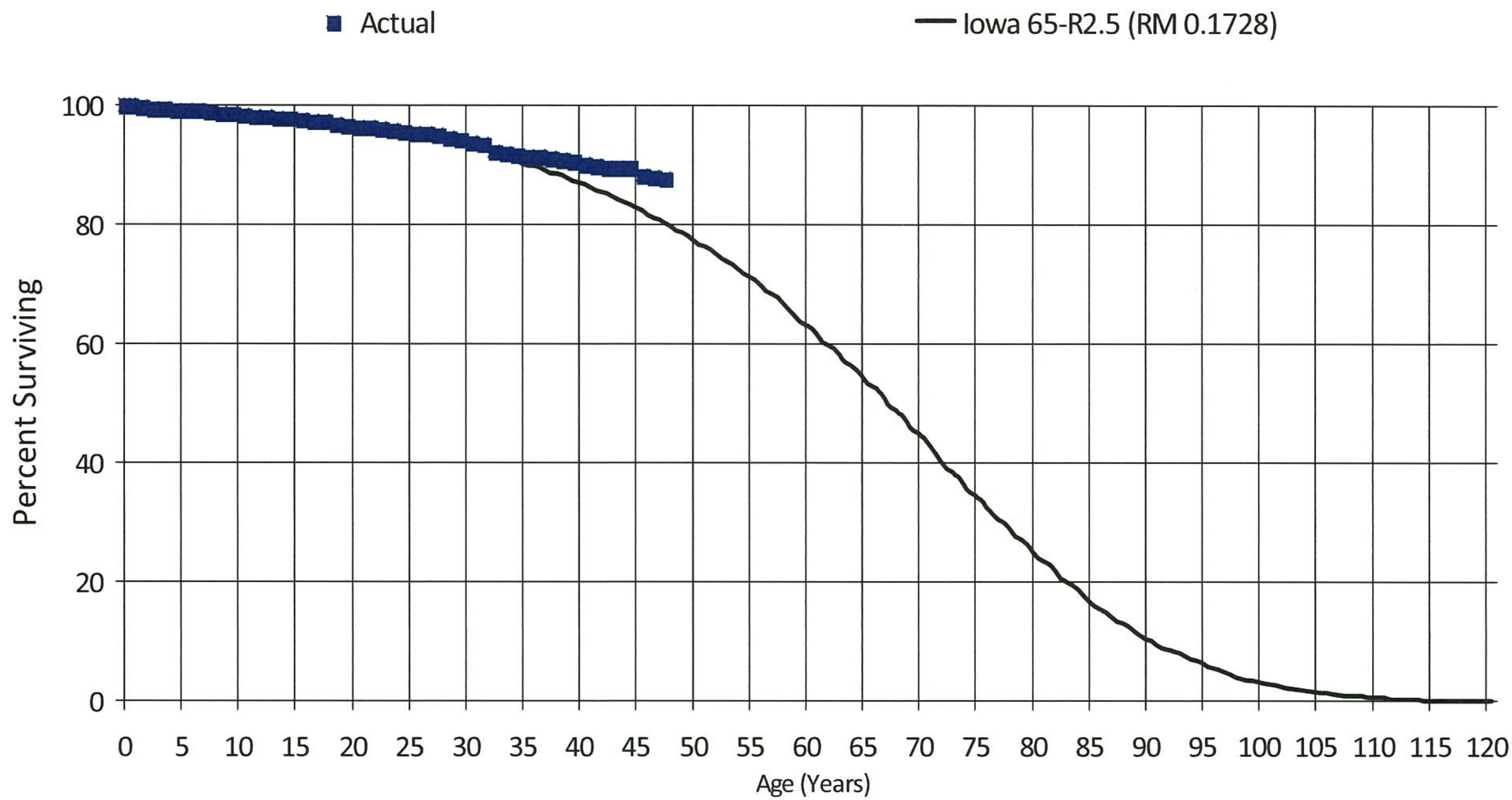
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	14,243,949	189,252	0.0133	0.9867	89.49
45.5	12,791,965	45,125	0.0035	0.9965	88.30
46.5	11,884,719	20,694	0.0017	0.9983	87.99
47.5	10,079,832	29,912	0.0030	0.9970	87.84
48.5	8,731,407	22,418	0.0026	0.9974	87.58
49.5	7,900,279	29,658	0.0038	0.9963	87.35
50.5	7,319,726	13,896	0.0019	0.9981	87.02
51.5	6,415,419	13,455	0.0021	0.9979	86.85
52.5	5,967,592	7,800	0.0013	0.9987	86.67
53.5	5,400,690	13,916	0.0026	0.9974	86.56
54.5	4,745,668	24,234	0.0051	0.9949	86.34
55.5	4,424,295	8,459	0.0019	0.9981	85.90
56.5	4,319,275	13,829	0.0032	0.9968	85.74
57.5	4,212,348	13,396	0.0032	0.9968	85.47
58.5	120,071	1,196	0.0100	0.9900	85.20
59.5	118,875	484	0.0041	0.9959	84.35
60.5	118,391	0	0.0000	1.0000	84.01
61.5	118,391	2,400	0.0203	0.9797	84.01
62.5	115,991	732	0.0063	0.9937	82.31
63.5	115,259	104	0.0009	0.9991	81.79
64.5	115,155	0	0.0000	1.0000	81.72
65.5	115,155	1,051	0.0091	0.9909	81.72
66.5	114,104	5,097	0.0447	0.9553	80.97
67.5	109,007	9,619	0.0882	0.9118	77.35
68.5	99,388	15,233	0.1533	0.8467	70.52
69.5	84,155	5,371	0.0638	0.9362	59.71
70.5	78,784	16,139	0.2049	0.7952	55.90
71.5	62,645	30,099	0.4805	0.5195	44.45
72.5	32,546	20,729	0.6369	0.3631	23.09
73.5	11,817	11,817	1.0000		8.38

FortisBC Energy

Account #: 47500 - Distribution Plant - Systems - Mains

Actual and Smooth Survivor Curves

Placement Band - 1924 - 2017 Experience Band - 1963 - 2017



FortisBC Energy

Account #: 47510 - Bio Gas - Mains - Municipal Land

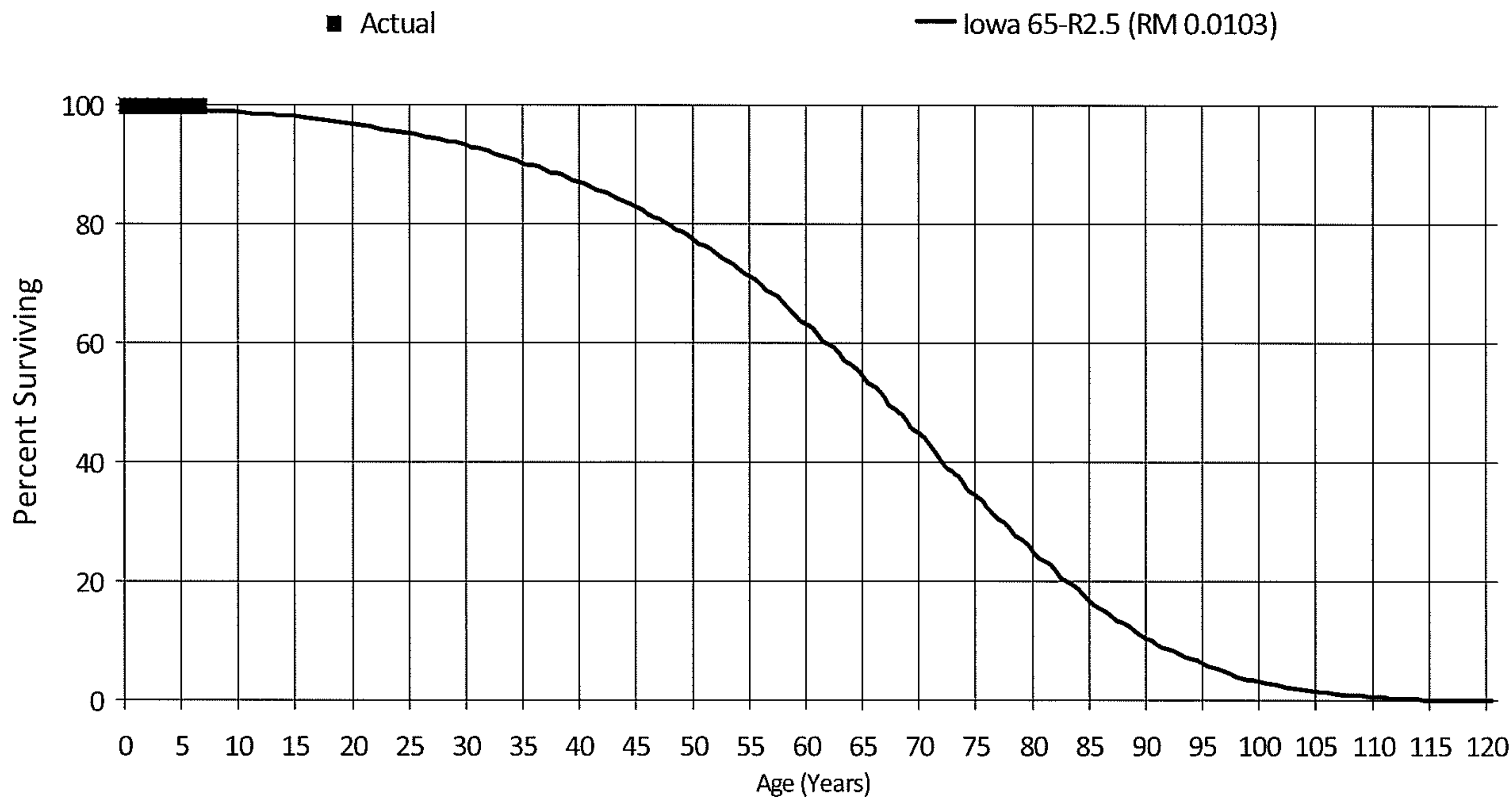
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,600,648	0	0.0000	1.0000	100.00
0.5	1,600,648	0	0.0000	1.0000	100.00
1.5	1,599,670	0	0.0000	1.0000	100.00
2.5	1,331,426	0	0.0000	1.0000	100.00
3.5	490,005	0	0.0000	1.0000	100.00
4.5	490,005	0	0.0000	1.0000	100.00
5.5	78,295	0	0.0000	1.0000	100.00
6.5	73,653	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 47510 - Bio Gas - Mains - Municipal Land

Actual and Smooth Survivor Curves

Placement Band - 2010 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 47600 - Distribution Plant - NGV Fuel Equipment

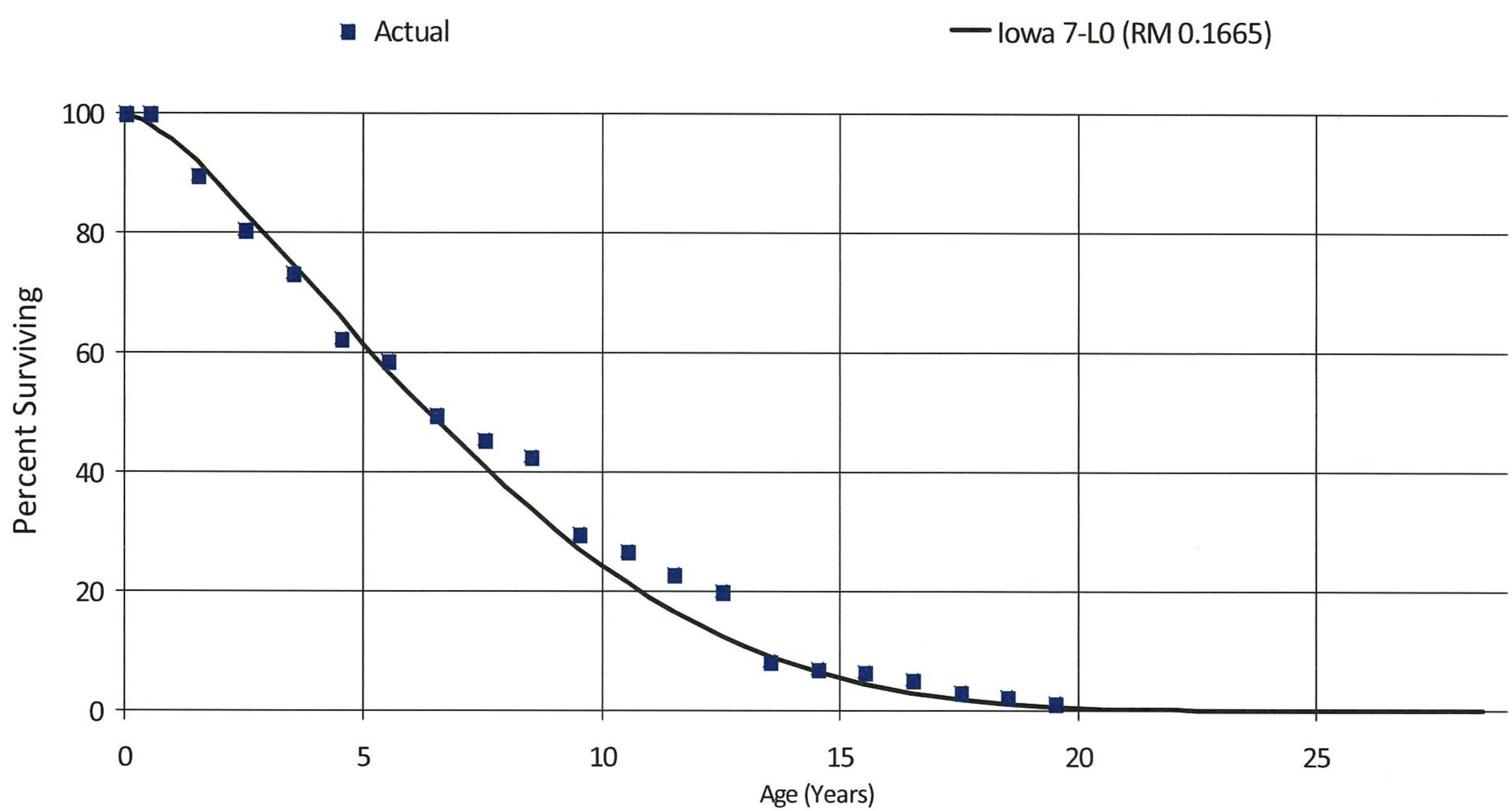
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	10,642,311	100	0.0000	1.0000	100.00
0.5	10,642,211	1,096,943	0.1031	0.8969	100.00
1.5	9,545,267	969,105	0.1015	0.8985	89.69
2.5	8,301,240	765,596	0.0922	0.9078	80.58
3.5	7,535,644	1,127,045	0.1496	0.8504	73.15
4.5	6,408,599	353,582	0.0552	0.9448	62.21
5.5	6,055,017	951,620	0.1572	0.8428	58.78
6.5	4,906,125	407,191	0.0830	0.9170	49.54
7.5	4,498,934	278,800	0.0620	0.9380	45.43
8.5	4,220,134	1,279,856	0.3033	0.6967	42.61
9.5	2,940,278	278,533	0.0947	0.9053	29.69
10.5	2,661,745	399,241	0.1500	0.8500	26.88
11.5	2,262,504	273,868	0.1211	0.8790	22.85
12.5	1,988,635	1,159,465	0.5831	0.4170	20.08
13.5	829,170	142,747	0.1722	0.8278	8.37
14.5	686,423	40,654	0.0592	0.9408	6.93
15.5	645,769	125,269	0.1940	0.8060	6.52
16.5	520,500	209,271	0.4021	0.5979	5.26
17.5	169,834	50,154	0.2953	0.7047	3.15
18.5	119,680	56,248	0.4700	0.5300	2.22
19.5	63,432	63,432	1.0000		1.18

FortisBC Energy

Account #: 47600 - Distribution Plant - NGV Fuel Equipment

Actual and Smooth Survivor Curves

Placement Band - 1983 - 2017 Experience Band - 1985 - 2017



FortisBC Energy

Account #: 47710 - Distribution Plant - Measuring and Regulating

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	160,747,688	340,158	0.0021	0.9979	100.00
0.5	146,643,496	268,045	0.0018	0.9982	99.79
1.5	133,091,063	393,510	0.0030	0.9970	99.61
2.5	123,639,324	338,282	0.0027	0.9973	99.32
3.5	121,122,957	492,541	0.0041	0.9959	99.05
4.5	112,701,208	417,339	0.0037	0.9963	98.65
5.5	107,104,909	549,147	0.0051	0.9949	98.28
6.5	102,454,838	745,624	0.0073	0.9927	97.78
7.5	98,098,023	652,312	0.0067	0.9934	97.07
8.5	92,471,388	1,225,052	0.0133	0.9868	96.42
9.5	87,751,659	491,010	0.0056	0.9944	95.14
10.5	81,737,565	705,167	0.0086	0.9914	94.61
11.5	73,172,655	828,004	0.0113	0.9887	93.79
12.5	67,558,223	937,486	0.0139	0.9861	92.73
13.5	62,967,939	971,540	0.0154	0.9846	91.44
14.5	54,615,055	727,249	0.0133	0.9867	90.03
15.5	50,721,177	597,419	0.0118	0.9882	88.83
16.5	45,556,417	602,632	0.0132	0.9868	87.78
17.5	41,833,324	688,517	0.0165	0.9835	86.62
18.5	38,870,283	342,965	0.0088	0.9912	85.19
19.5	36,142,278	808,108	0.0224	0.9776	84.44
20.5	31,916,553	521,876	0.0164	0.9837	82.55
21.5	28,190,019	431,563	0.0153	0.9847	81.20
22.5	23,033,036	505,338	0.0219	0.9781	79.96
23.5	19,467,490	263,927	0.0136	0.9864	78.21
24.5	17,335,647	419,348	0.0242	0.9758	77.15
25.5	14,416,662	373,531	0.0259	0.9741	75.28
26.5	11,152,274	351,489	0.0315	0.9685	73.33
27.5	10,688,287	384,858	0.0360	0.9640	71.02
28.5	9,971,716	370,702	0.0372	0.9628	68.46
29.5	2,951,429	93,272	0.0316	0.9684	65.91
30.5	2,381,363	114,265	0.0480	0.9520	63.83
31.5	1,674,909	43,234	0.0258	0.9742	60.77
32.5	1,556,608	120,572	0.0775	0.9225	59.20
33.5	1,313,507	70,246	0.0535	0.9465	54.61
34.5	1,056,967	54,186	0.0513	0.9487	51.69
35.5	880,258	220,523	0.2505	0.7495	49.04
36.5	647,578	2,938	0.0045	0.9955	36.75
37.5	565,704	225,188	0.3981	0.6019	36.58
38.5	321,987	19,357	0.0601	0.9399	22.02
39.5	298,289	3,463	0.0116	0.9884	20.70
40.5	286,714	300	0.0011	0.9990	20.46
41.5	260,169	30,385	0.1168	0.8832	20.44
42.5	227,233	40,318	0.1774	0.8226	18.05
43.5	185,679	22,263	0.1199	0.8801	14.85

FortisBC Energy

Account #: 47710 - Distribution Plant - Measuring and Regulating

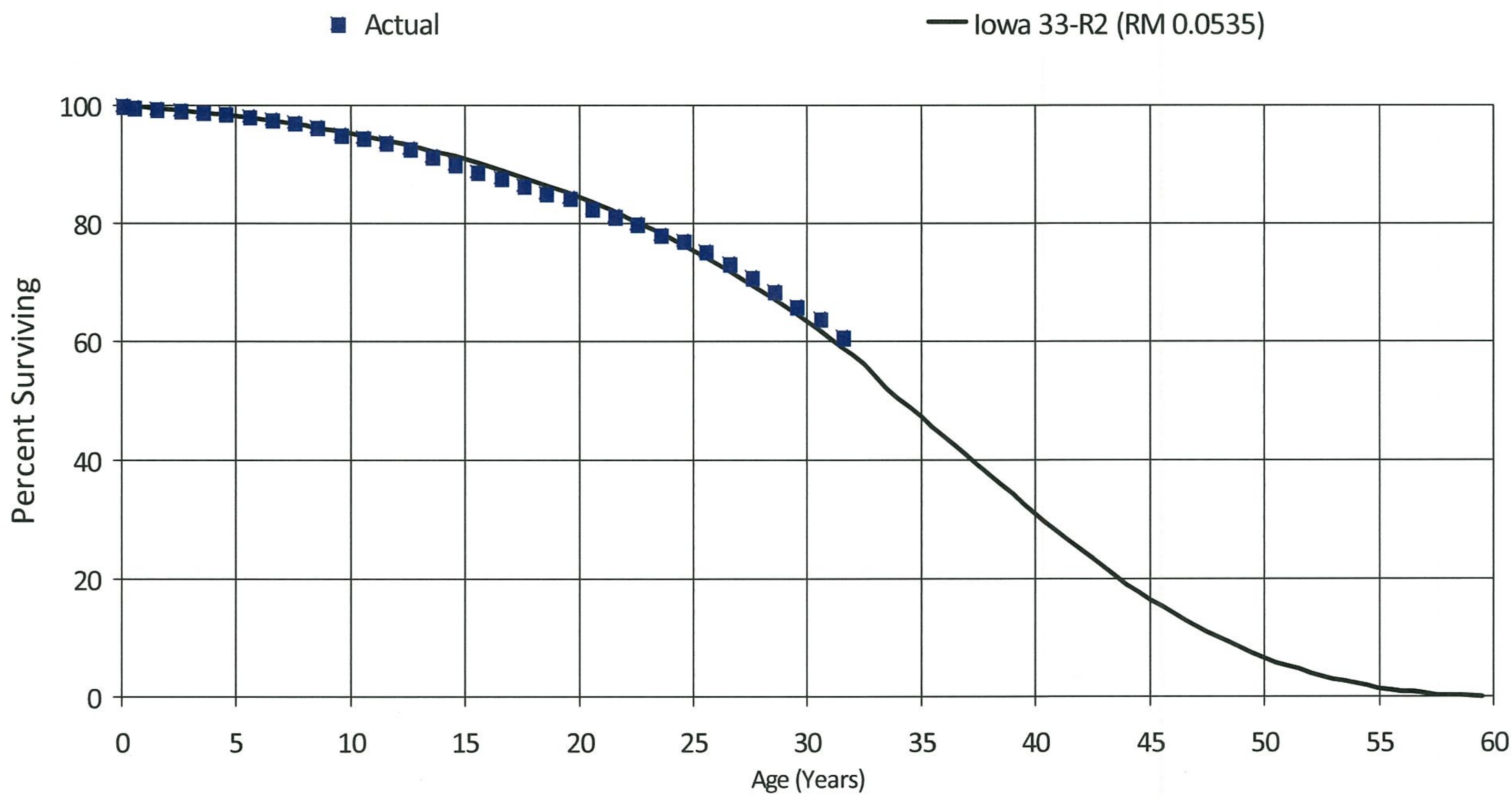
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	76,824	13,855	0.1804	0.8197	13.07
45.5	62,969	0	0.0000	1.0000	10.71
46.5	57,515	2,101	0.0365	0.9635	10.71
47.5	51,240	0	0.0000	1.0000	10.32
48.5	49,595	0	0.0000	1.0000	10.32
49.5	49,595	130	0.0026	0.9974	10.32
50.5	49,466	6,204	0.1254	0.8746	10.29
51.5	42,851	0	0.0000	1.0000	9.00
52.5	42,066	0	0.0000	1.0000	9.00
53.5	41,852	0	0.0000	1.0000	9.00
54.5	40,513	0	0.0000	1.0000	9.00
55.5	40,513	0	0.0000	1.0000	9.00
56.5	40,513	0	0.0000	1.0000	9.00
57.5	40,513	710	0.0175	0.9825	9.00
58.5	39,803	0	0.0000	1.0000	8.84
59.5	0	0	0.0000	0.0000	8.84

FortisBC Energy

Account #: 47710 - Distribution Plant - Measuring and Regulating

Actual and Smooth Survivor Curves

Placement Band - 1957 - 2017 Experience Band - 1959 - 2017



FortisBC Energy

Account #: 47720 - Distribution Plant - Telemetry

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,601,090	105,932	0.0064	0.9936	100.00
0.5	14,572,431	25,599	0.0018	0.9982	99.36
1.5	12,754,632	32,437	0.0025	0.9975	99.19
2.5	11,483,835	15,774	0.0014	0.9986	98.94
3.5	9,883,100	66,316	0.0067	0.9933	98.80
4.5	8,327,659	85,246	0.0102	0.9898	98.14
5.5	7,152,841	50,722	0.0071	0.9929	97.14
6.5	6,760,474	51,317	0.0076	0.9924	96.45
7.5	6,266,078	84,070	0.0134	0.9866	95.72
8.5	6,077,494	106,882	0.0176	0.9824	94.44
9.5	5,779,212	56,169	0.0097	0.9903	92.78
10.5	5,675,228	111,082	0.0196	0.9804	91.88
11.5	5,374,585	94,430	0.0176	0.9824	90.08
12.5	5,249,204	137,238	0.0261	0.9739	88.50
13.5	5,009,349	39,773	0.0079	0.9921	86.19
14.5	4,620,450	146,647	0.0317	0.9683	85.51
15.5	4,327,772	20,621	0.0048	0.9952	82.80
16.5	3,941,910	30,647	0.0078	0.9922	82.41
17.5	3,659,659	8,954	0.0025	0.9976	81.77
18.5	3,376,341	128,945	0.0382	0.9618	81.57
19.5	2,959,182	23,213	0.0078	0.9922	78.45
20.5	2,450,327	151,398	0.0618	0.9382	77.83
21.5	1,000,565	29,241	0.0292	0.9708	73.02
22.5	746,086	7,673	0.0103	0.9897	70.89
23.5	533,624	12,290	0.0230	0.9770	70.16
24.5	430,261	7,588	0.0176	0.9824	68.54
25.5	355,213	2,374	0.0067	0.9933	67.33
26.5	310,447	0	0.0000	1.0000	66.88
27.5	296,398	1,472	0.0050	0.9950	66.88
28.5	285,986	10,643	0.0372	0.9628	66.55
29.5	226,035	955	0.0042	0.9958	64.07
30.5	224,473	0	0.0000	1.0000	63.80
31.5	162,765	10,900	0.0670	0.9330	63.80
32.5	117,002	0	0.0000	1.0000	59.53
33.5	114,636	4,013	0.0350	0.9650	59.53
34.5	61,560	1,075	0.0175	0.9825	57.45
35.5	42,816	15,708	0.3669	0.6331	56.45
36.5	27,108	0	0.0000	1.0000	35.74
37.5	27,108	493	0.0182	0.9818	35.74
38.5	12,729	0	0.0000	1.0000	35.09
39.5	12,729	0	0.0000	1.0000	35.09
40.5	12,729	0	0.0000	1.0000	35.09
41.5	12,533	1,325	0.1057	0.8943	35.09
42.5	11,208	0	0.0000	1.0000	31.38
43.5	11,208	0	0.0000	1.0000	31.38

FortisBC Energy

Account #: 47720 - Distribution Plant - Telemetry

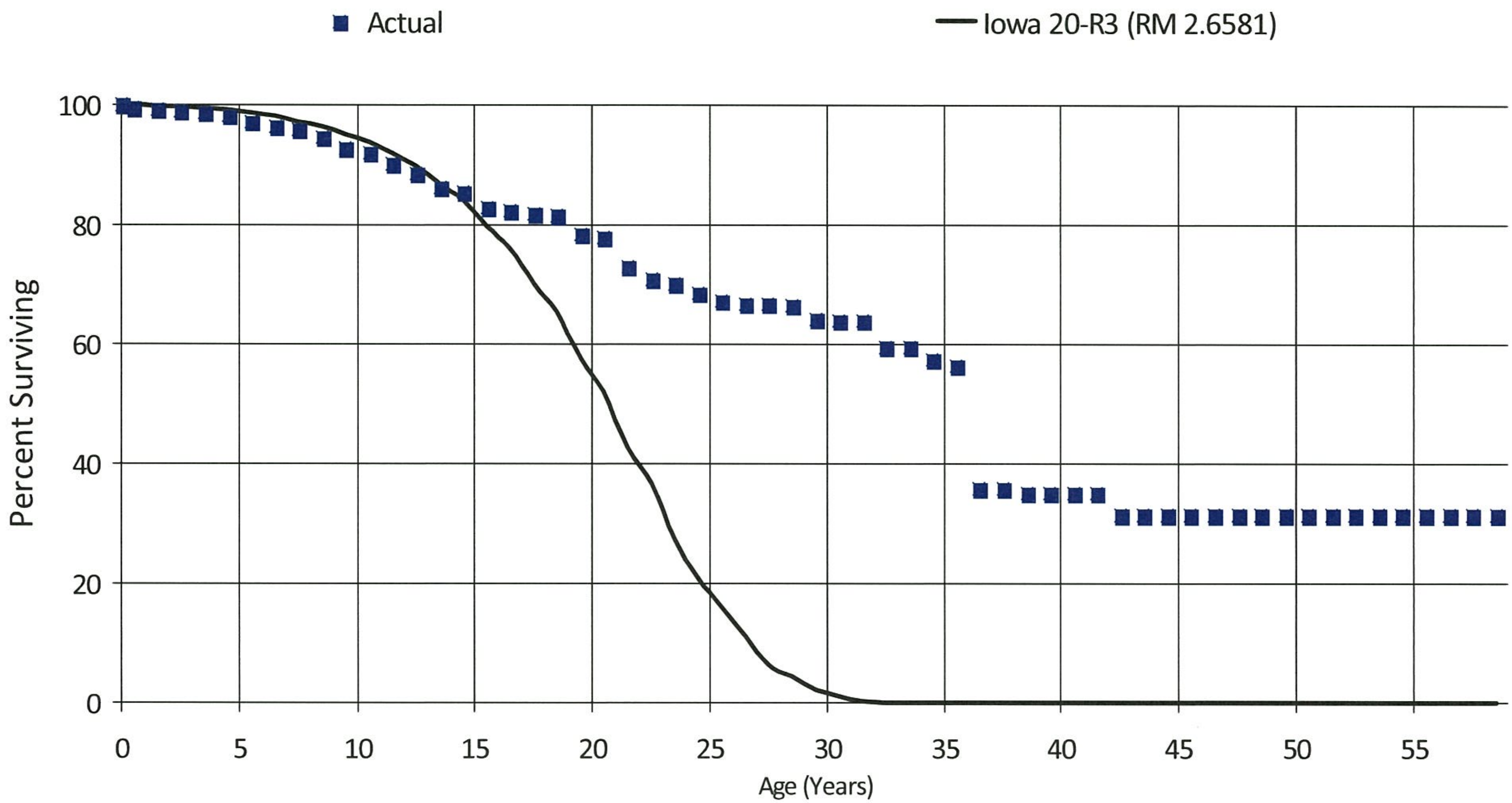
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	9,820	0	0.0000	1.0000	31.38
45.5	9,820	0	0.0000	1.0000	31.38
46.5	9,679	0	0.0000	1.0000	31.38
47.5	9,679	0	0.0000	1.0000	31.38
48.5	203	0	0.0000	1.0000	31.38
49.5	203	0	0.0000	1.0000	31.38
50.5	203	0	0.0000	1.0000	31.38
51.5	203	0	0.0000	1.0000	31.38
52.5	203	0	0.0000	1.0000	31.38
53.5	203	0	0.0000	1.0000	31.38
54.5	203	0	0.0000	1.0000	31.38
55.5	203	0	0.0000	1.0000	31.38
56.5	203	0	0.0000	1.0000	31.38
57.5	203	0	0.0000	1.0000	31.38
58.5	0	0	0.0000	0.0000	31.38

FortisBC Energy

Account #: 47720 - Distribution Plant - Telemetry

Actual and Smooth Survivor Curves

Placement Band - 1958 - 2017   Experience Band - 1971 - 2017



FortisBC Energy

Account #: 47740 - Bio Gas - Measuring and Regulating

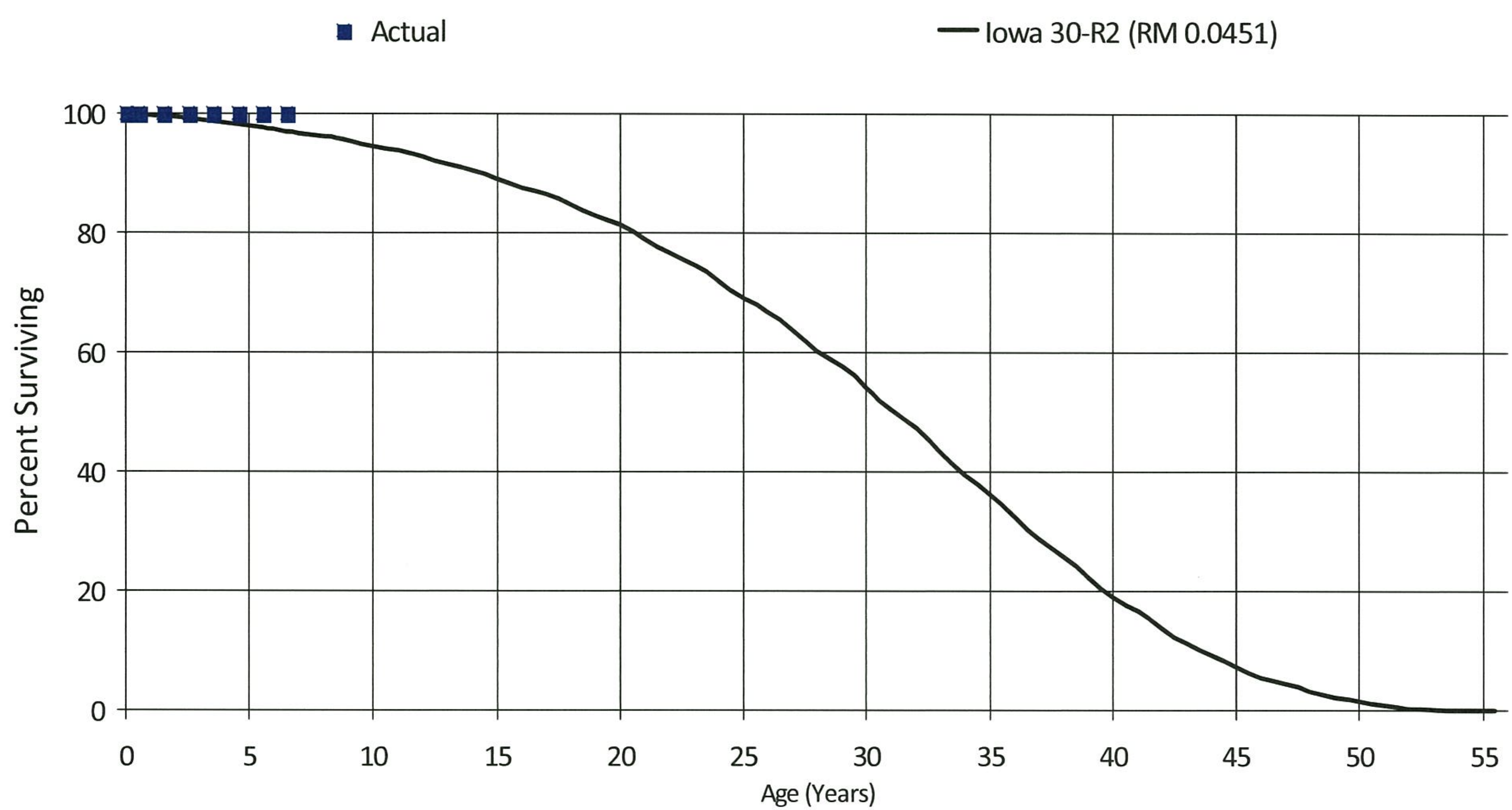
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,565,623	0	0.0000	1.0000	100.00
0.5	2,046,129	0	0.0000	1.0000	100.00
1.5	1,917,323	0	0.0000	1.0000	100.00
2.5	1,432,698	0	0.0000	1.0000	100.00
3.5	858,254	0	0.0000	1.0000	100.00
4.5	279,916	0	0.0000	1.0000	100.00
5.5	279,600	0	0.0000	1.0000	100.00
6.5	275,550	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 47740 - Bio Gas - Measuring and Regulating

Actual and Smooth Survivor Curves

Placement Band - 2010 - 2017   Experience Band - 2017 - 2017



FortisBC Energy

Account #: 47810 - Distribution Plant - Meters

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	345,459,181	237,255	0.0007	0.9993	100.00
0.5	327,659,683	520,228	0.0016	0.9984	99.93
1.5	311,163,106	1,122,311	0.0036	0.9964	99.77
2.5	296,798,132	844,559	0.0029	0.9972	99.41
3.5	285,919,780	1,391,258	0.0049	0.9951	99.13
4.5	273,119,739	1,728,692	0.0063	0.9937	98.65
5.5	260,772,815	1,287,672	0.0049	0.9951	98.03
6.5	249,270,689	2,171,290	0.0087	0.9913	97.55
7.5	239,052,444	2,167,218	0.0091	0.9909	96.70
8.5	229,331,010	2,391,205	0.0104	0.9896	95.82
9.5	219,969,121	4,600,216	0.0209	0.9791	94.82
10.5	206,588,310	2,651,681	0.0128	0.9872	92.84
11.5	196,395,288	5,010,712	0.0255	0.9745	91.65
12.5	183,962,858	5,021,661	0.0273	0.9727	89.31
13.5	166,308,108	8,791,357	0.0529	0.9471	86.87
14.5	142,078,423	8,280,811	0.0583	0.9417	82.28
15.5	123,265,174	6,108,408	0.0496	0.9504	77.48
16.5	113,097,469	5,267,744	0.0466	0.9534	73.64
17.5	102,469,792	5,830,561	0.0569	0.9431	70.21
18.5	89,195,984	4,770,419	0.0535	0.9465	66.22
19.5	79,947,529	5,208,575	0.0652	0.9349	62.68
20.5	69,554,700	4,619,582	0.0664	0.9336	58.60
21.5	58,324,531	5,253,431	0.0901	0.9099	54.71
22.5	48,757,919	2,518,920	0.0517	0.9483	49.78
23.5	43,292,267	4,757,196	0.1099	0.8901	47.21
24.5	36,338,492	2,214,277	0.0609	0.9391	42.02
25.5	32,375,787	1,247,468	0.0385	0.9615	39.46
26.5	30,275,840	1,154,230	0.0381	0.9619	37.94
27.5	17,742,212	836,323	0.0471	0.9529	36.49
28.5	12,498,780	668,109	0.0535	0.9466	34.77
29.5	637,856	287,219	0.4503	0.5497	32.91
30.5	350,637	152,679	0.4354	0.5646	18.09
31.5	197,958	114,772	0.5798	0.4202	10.21
32.5	83,186	18,397	0.2212	0.7788	4.29
33.5	64,789	0	0.0000	1.0000	3.34
34.5	64,789	0	0.0000	1.0000	3.34
35.5	64,789	0	0.0000	1.0000	3.34
36.5	64,789	0	0.0000	1.0000	3.34
37.5	64,789	0	0.0000	1.0000	3.34
38.5	64,789	0	0.0000	1.0000	3.34
39.5	64,789	0	0.0000	1.0000	3.34
40.5	64,789	0	0.0000	1.0000	3.34
41.5	64,789	0	0.0000	1.0000	3.34
42.5	64,789	0	0.0000	1.0000	3.34
43.5	64,789	0	0.0000	1.0000	3.34

FortisBC Energy

Account #: 47810 - Distribution Plant - Meters

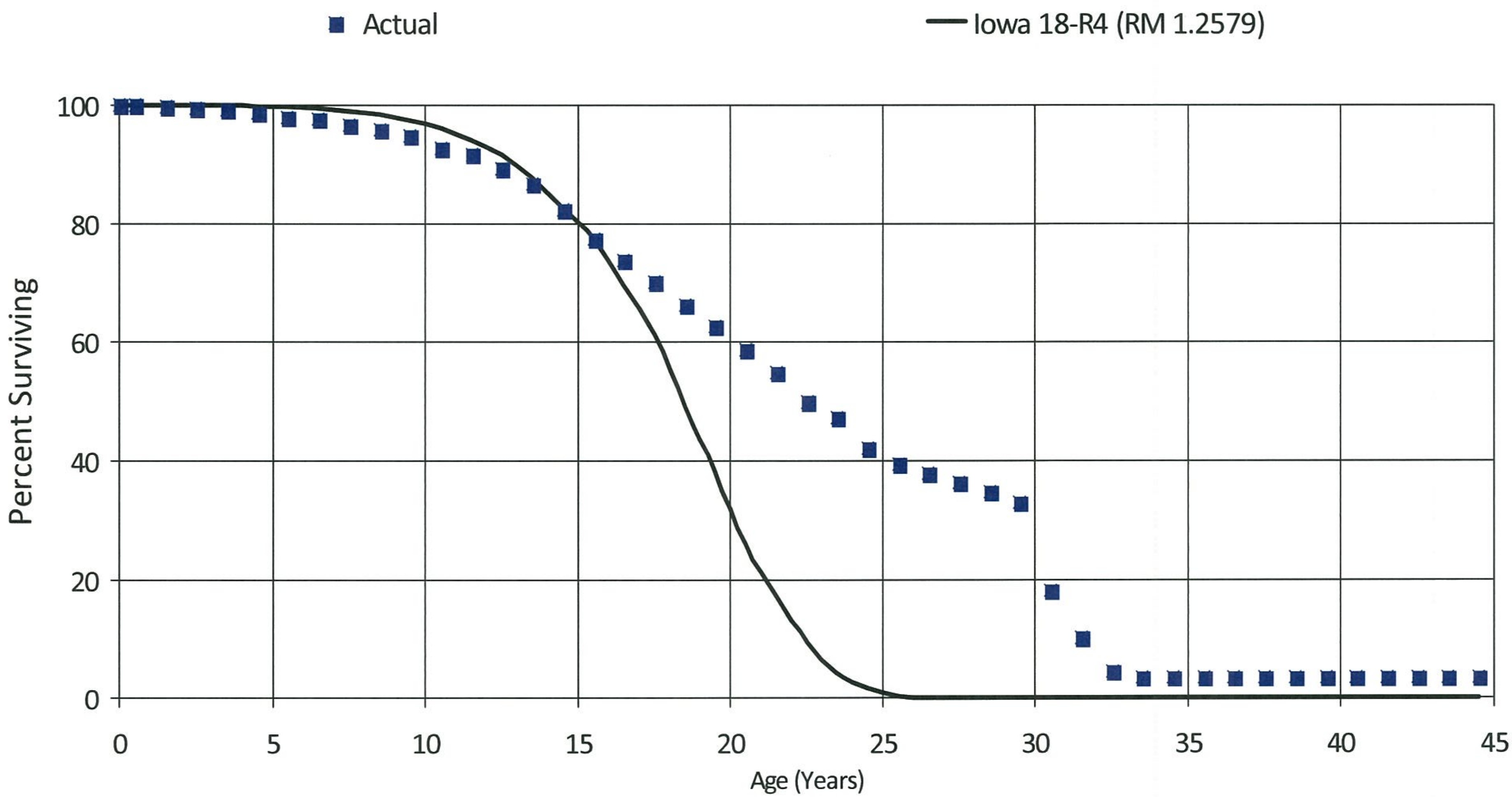
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	64,789	64,789	1.0000		3.34

FortisBC Energy

Account #: 47810 - Distribution Plant - Meters

Actual and Smooth Survivor Curves

Placement Band - 1963 - 2017 Experience Band - 1963 - 2017



FortisBC Energy

Account #: 47820 - Distribution Plant - Instruments

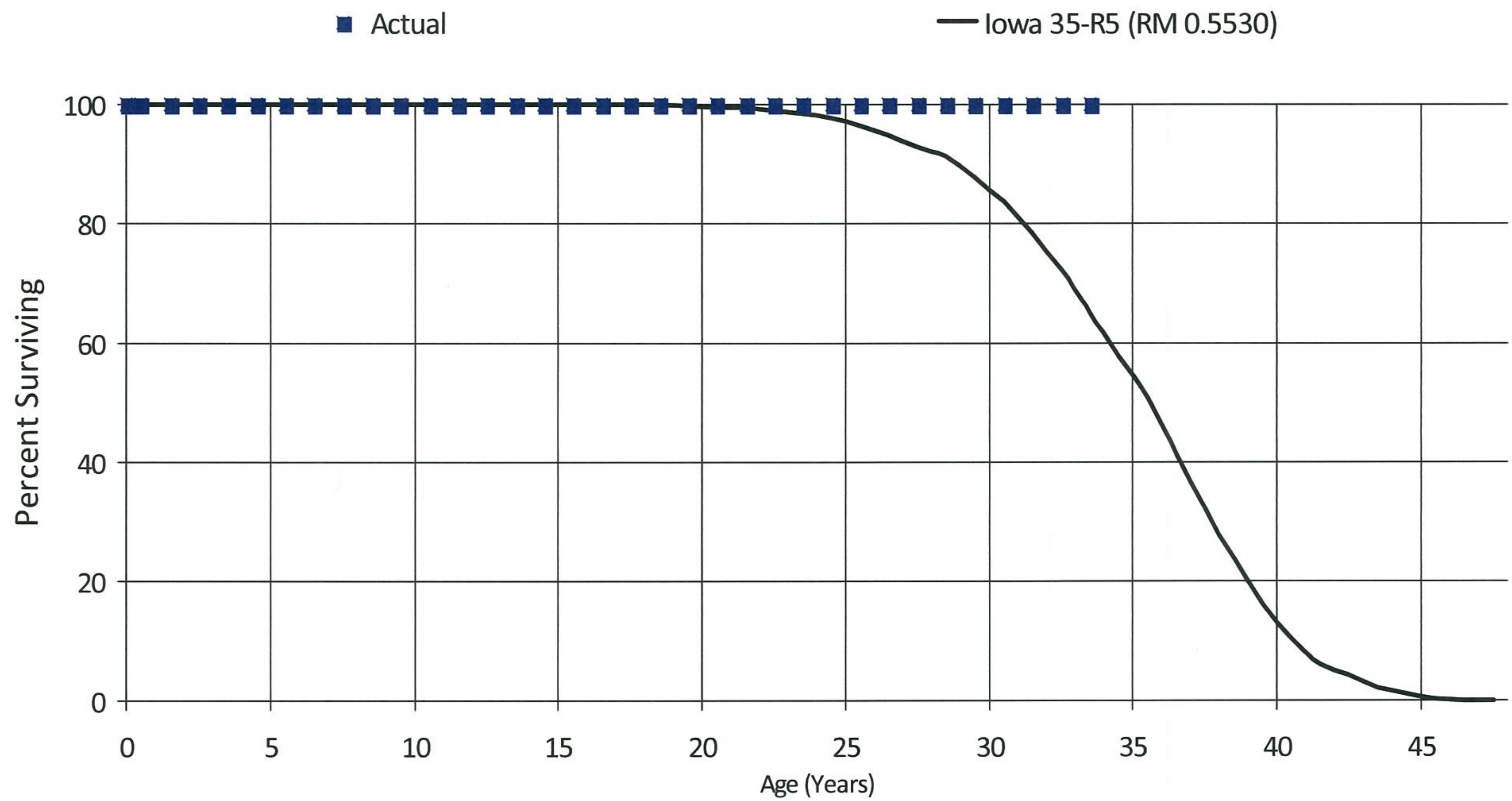
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	13,401,830	0	0.0000	1.0000	100.00
0.5	12,956,785	0	0.0000	1.0000	100.00
1.5	12,373,032	0	0.0000	1.0000	100.00
2.5	12,143,331	0	0.0000	1.0000	100.00
3.5	11,944,398	0	0.0000	1.0000	100.00
4.5	11,889,283	0	0.0000	1.0000	100.00
5.5	11,771,055	0	0.0000	1.0000	100.00
6.5	11,479,242	0	0.0000	1.0000	100.00
7.5	11,305,173	0	0.0000	1.0000	100.00
8.5	11,251,377	0	0.0000	1.0000	100.00
9.5	10,942,940	0	0.0000	1.0000	100.00
10.5	10,495,227	0	0.0000	1.0000	100.00
11.5	9,987,170	0	0.0000	1.0000	100.00
12.5	9,698,879	0	0.0000	1.0000	100.00
13.5	8,335,502	0	0.0000	1.0000	100.00
14.5	6,944,840	0	0.0000	1.0000	100.00
15.5	6,588,236	0	0.0000	1.0000	100.00
16.5	6,212,369	0	0.0000	1.0000	100.00
17.5	5,958,577	0	0.0000	1.0000	100.00
18.5	5,603,645	0	0.0000	1.0000	100.00
19.5	5,549,818	0	0.0000	1.0000	100.00
20.5	5,142,386	0	0.0000	1.0000	100.00
21.5	4,486,715	0	0.0000	1.0000	100.00
22.5	3,701,088	0	0.0000	1.0000	100.00
23.5	2,799,898	0	0.0000	1.0000	100.00
24.5	1,964,237	0	0.0000	1.0000	100.00
25.5	1,209,578	0	0.0000	1.0000	100.00
26.5	865,075	0	0.0000	1.0000	100.00
27.5	699,637	0	0.0000	1.0000	100.00
28.5	605,650	0	0.0000	1.0000	100.00
29.5	490,489	0	0.0000	1.0000	100.00
30.5	393,682	0	0.0000	1.0000	100.00
31.5	370,326	0	0.0000	1.0000	100.00
32.5	364,695	0	0.0000	1.0000	100.00
33.5	361,762	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 47820 - Distribution Plant - Instruments

Actual and Smooth Survivor Curves

Placement Band - 1983 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 47830 - Bio Gas - Meters

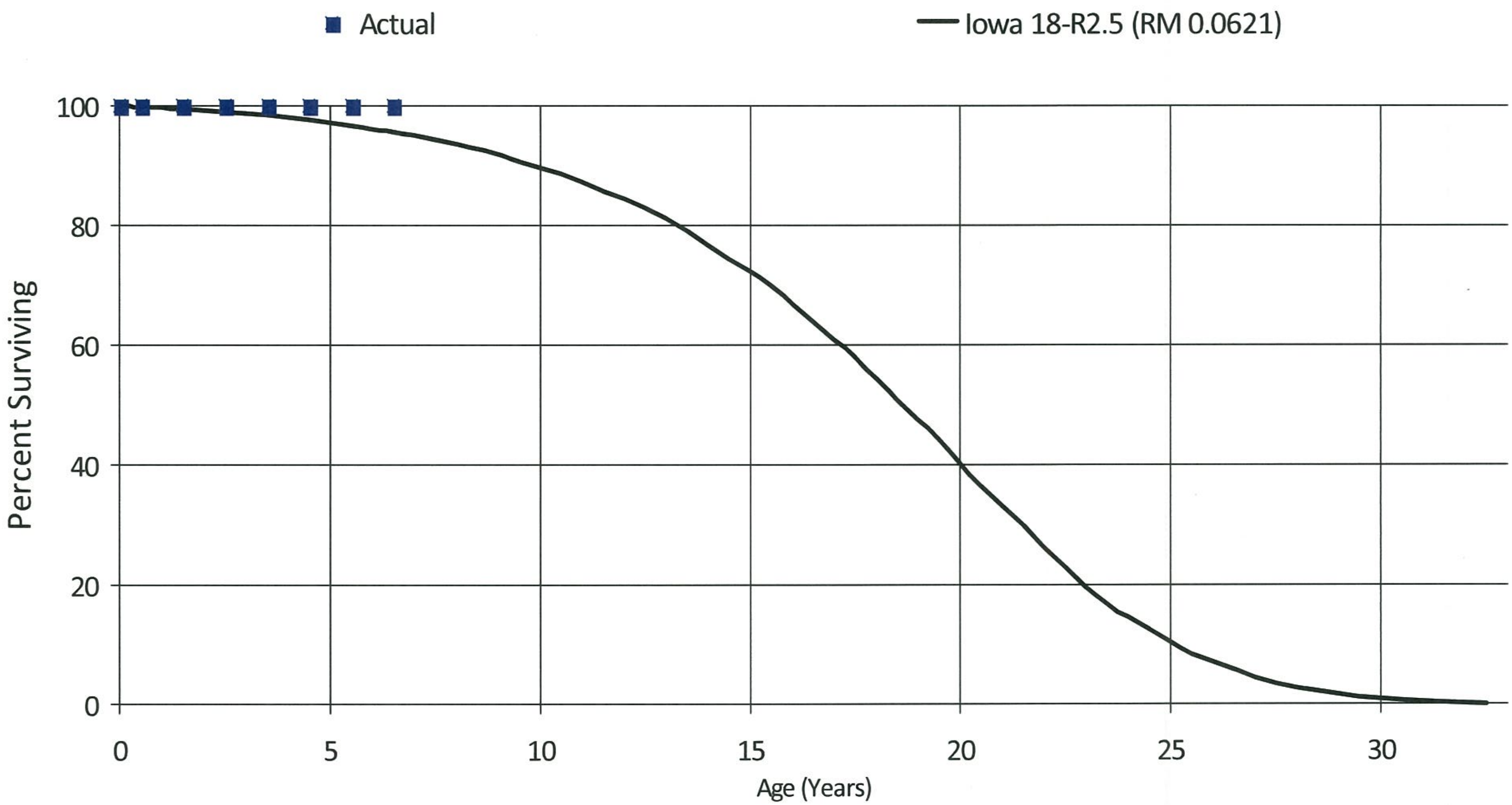
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	35,277	0	0.0000	1.0000	100.00
0.5	35,277	0	0.0000	1.0000	100.00
1.5	30,794	0	0.0000	1.0000	100.00
2.5	10,298	0	0.0000	1.0000	100.00
3.5	10,298	0	0.0000	1.0000	100.00
4.5	7,334	0	0.0000	1.0000	100.00
5.5	7,334	0	0.0000	1.0000	100.00
6.5	7,334	0	0.0000	1.0000	100.00

FortisBC Energy

Account #: 47830 - Bio Gas - Meters

Actual and Smooth Survivor Curves

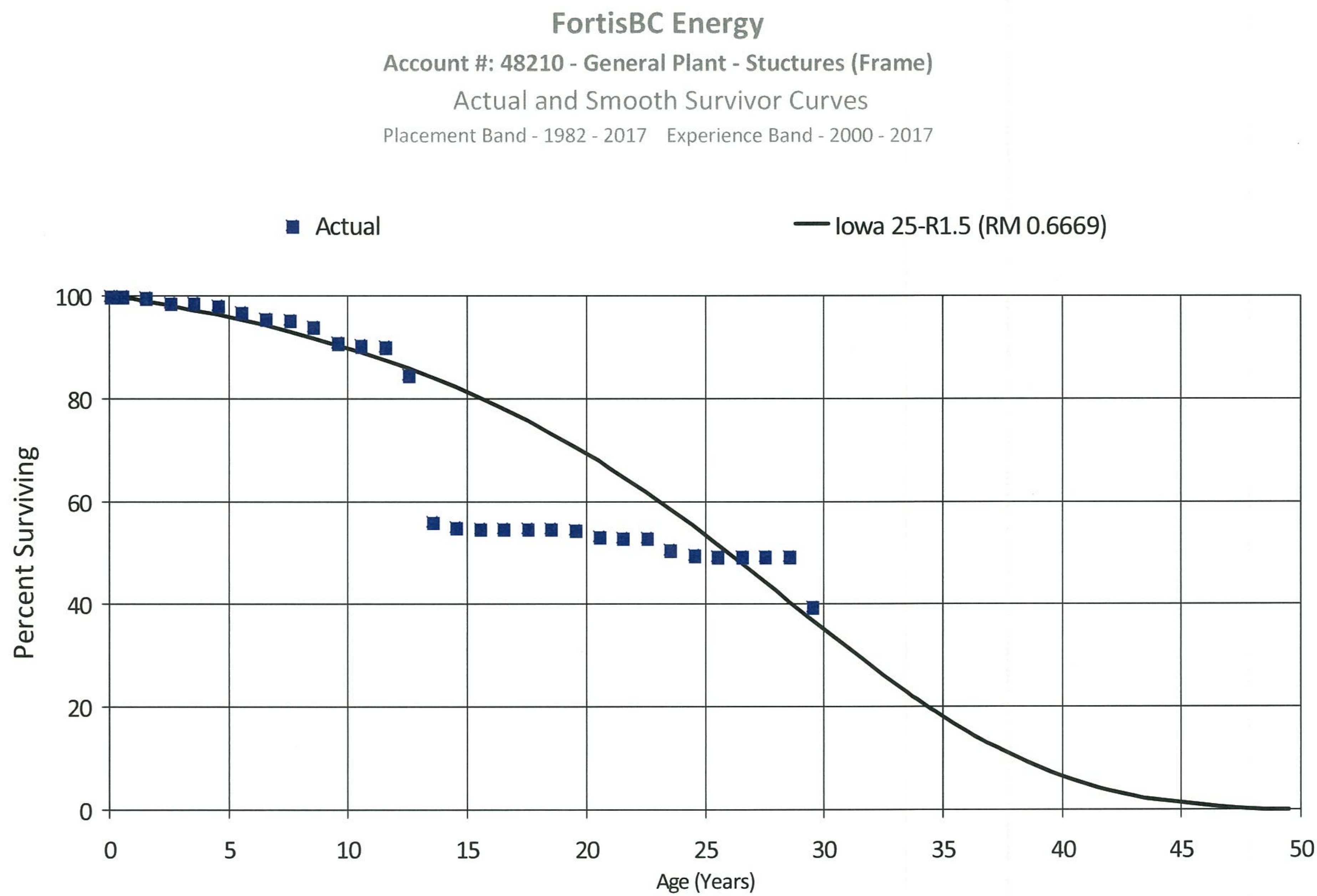
Placement Band - 2010 - 2017 Experience Band - 2017 - 2017



FortisBC Energy

Account #: 48210 - General Plant - Stuctures (Frame)

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	22,190,095	1,593	0.0001	0.9999	100.00
0.5	20,630,247	68,550	0.0033	0.9967	99.99
1.5	18,779,591	184,025	0.0098	0.9902	99.66
2.5	18,094,674	19,013	0.0011	0.9990	98.68
3.5	18,127,557	84,405	0.0047	0.9953	98.58
4.5	17,775,195	231,207	0.0130	0.9870	98.12
5.5	17,304,839	234,553	0.0136	0.9865	96.84
6.5	14,372,666	39,255	0.0027	0.9973	95.53
7.5	12,880,631	162,609	0.0126	0.9874	95.27
8.5	11,194,060	370,654	0.0331	0.9669	94.07
9.5	10,718,407	75,021	0.0070	0.9930	90.96
10.5	10,531,305	11,320	0.0011	0.9989	90.32
11.5	14,832,386	911,273	0.0614	0.9386	90.22
12.5	13,702,841	4,636,905	0.3384	0.6616	84.68
13.5	8,936,823	163,709	0.0183	0.9817	56.03
14.5	8,543,998	14,372	0.0017	0.9983	55.00
15.5	7,639,132	0	0.0000	1.0000	54.91
16.5	6,674,110	12,595	0.0019	0.9981	54.91
17.5	6,449,465	3,408	0.0005	0.9995	54.81
18.5	6,306,523	28,873	0.0046	0.9954	54.78
19.5	5,816,112	150,670	0.0259	0.9741	54.53
20.5	5,558,511	1,909	0.0003	0.9997	53.12
21.5	4,595,330	10,000	0.0022	0.9978	53.10
22.5	2,160,446	90,309	0.0418	0.9582	52.98
23.5	1,142,475	27,702	0.0243	0.9758	50.77
24.5	1,110,716	3,316	0.0030	0.9970	49.54
25.5	1,022,969	0	0.0000	1.0000	49.39
26.5	727,614	0	0.0000	1.0000	49.39
27.5	727,292	0	0.0000	1.0000	49.39
28.5	727,292	145,966	0.2007	0.7993	49.39
29.5	0	0	0.0000	0.0000	39.48


FortisBC Energy
Account #: 48210 - General Plant - Stuctures (Frame)
Actual and Smooth Survivor Curves
Placement Band - 1982 - 2017 Experience Band - 2000 - 2017
Actual
Iowa 25-R1.5 (RM 0.6669)
Percent Surviving
100
80
60
40
20
0
0
5
10
15
20
25
30
35
40
45
50
Age (Years)

FortisBC Energy
Account #: 48220 - General Plant - Structures (Masonry)

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	117,276,656	12,000	0.0001	0.9999	100.00
0.5	114,465,640	40,054	0.0004	0.9997	99.99
1.5	111,549,934	396	0.0000	1.0000	99.96
2.5	110,213,086	0	0.0000	1.0000	99.96
3.5	110,165,343	6,229	0.0001	0.9999	99.96
4.5	108,932,040	32,473	0.0003	0.9997	99.95
5.5	95,493,349	4,411	0.0001	1.0000	99.92
6.5	86,644,592	85,556	0.0010	0.9990	99.92
7.5	85,248,919	61,830	0.0007	0.9993	99.82
8.5	83,565,886	38,626	0.0005	0.9995	99.75
9.5	82,532,502	1,840	0.0000	1.0000	99.70
10.5	79,295,861	115,397	0.0015	0.9985	99.70
11.5	78,055,682	889,442	0.0114	0.9886	99.55
12.5	25,596,904	72,348	0.0028	0.9972	98.42
13.5	24,525,761	20,937	0.0009	0.9992	98.14
14.5	23,018,983	1,080	0.0001	1.0000	98.06
15.5	22,525,254	489,860	0.0218	0.9783	98.06
16.5	20,738,958	10,000	0.0005	0.9995	95.93
17.5	20,066,614	0	0.0000	1.0000	95.88
18.5	19,839,473	0	0.0000	1.0000	95.88
19.5	18,463,129	160,000	0.0087	0.9913	95.88
20.5	17,856,399	154,813	0.0087	0.9913	95.05
21.5	13,495,967	344,721	0.0255	0.9745	94.23
22.5	9,236,700	0	0.0000	1.0000	91.82
23.5	5,472,735	0	0.0000	1.0000	91.82
24.5	5,330,943	0	0.0000	1.0000	91.82
25.5	2,017,938	0	0.0000	1.0000	91.82
26.5	1,990,314	0	0.0000	1.0000	91.82
27.5	1,875,474	42,784	0.0228	0.9772	91.82
28.5	1,380,016	19,545	0.0142	0.9858	89.73
29.5	852,822	0	0.0000	1.0000	88.46
30.5	849,472	0	0.0000	1.0000	88.46
31.5	849,226	0	0.0000	1.0000	88.46
32.5	848,139	0	0.0000	1.0000	88.46
33.5	802,601	0	0.0000	1.0000	88.46
34.5	791,560	0	0.0000	1.0000	88.46
35.5	783,805	0	0.0000	1.0000	88.46
36.5	774,836	15,000	0.0194	0.9806	88.46
37.5	754,915	0	0.0000	1.0000	86.75
38.5	449,087	0	0.0000	1.0000	86.75
39.5	428,730	0	0.0000	1.0000	86.75
40.5	419,803	0	0.0000	1.0000	86.75
41.5	171,033	0	0.0000	1.0000	86.75
42.5	170,852	0	0.0000	1.0000	86.75
43.5	170,163	0	0.0000	1.0000	86.75

FortisBC Energy

Account #: 48220 - General Plant - Structures (Masonry)

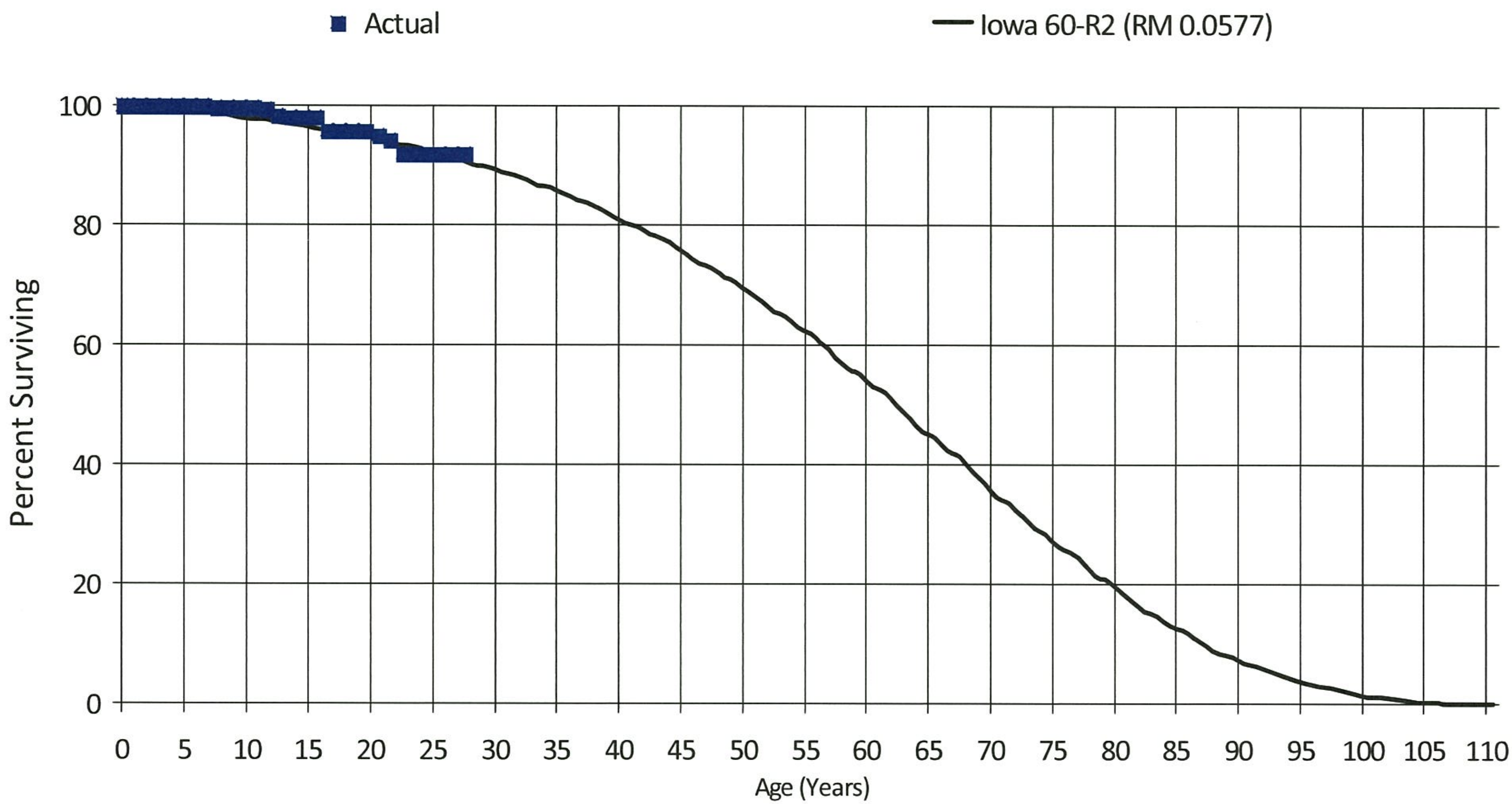
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	170,163	0	0.0000	1.0000	86.75
45.5	170,163	0	0.0000	1.0000	86.75
46.5	170,163	0	0.0000	1.0000	86.75
47.5	156,331	0	0.0000	1.0000	86.75
48.5	156,331	0	0.0000	1.0000	86.75
49.5	156,331	0	0.0000	1.0000	86.75
50.5	85,734	0	0.0000	1.0000	86.75
51.5	85,734	0	0.0000	1.0000	86.75
52.5	85,734	0	0.0000	1.0000	86.75
53.5	85,734	0	0.0000	1.0000	86.75
54.5	85,734	0	0.0000	1.0000	86.75
55.5	85,734	0	0.0000	1.0000	86.75
56.5	85,734	0	0.0000	1.0000	86.75

FortisBC Energy

Account #: 48220 - General Plant - Structures (Masonry)

Actual and Smooth Survivor Curves

Placement Band - 1960 - 2017   Experience Band - 1978 - 2017



FortisBC Energy

Account #: 48400 - General Plant - Vehicles

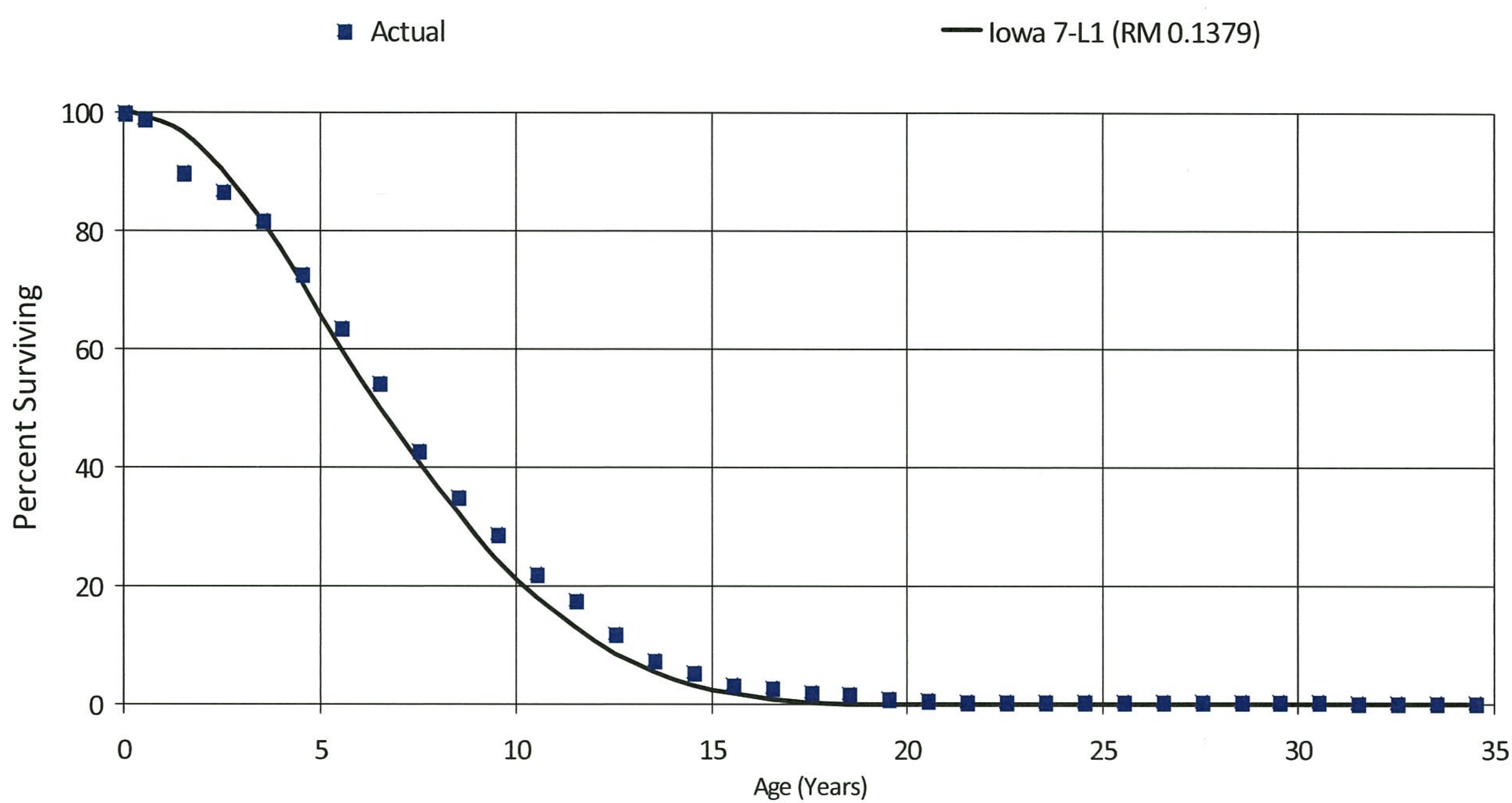
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	42,597,184	386,315	0.0091	0.9909	100.00
0.5	37,280,283	3,431,334	0.0920	0.9080	99.09
1.5	30,128,993	1,095,654	0.0364	0.9636	89.97
2.5	25,986,199	1,481,582	0.0570	0.9430	86.70
3.5	22,545,321	2,463,226	0.1093	0.8907	81.76
4.5	18,777,595	2,399,419	0.1278	0.8722	72.83
5.5	15,377,906	2,207,136	0.1435	0.8565	63.52
6.5	12,218,721	2,600,942	0.2129	0.7871	54.40
7.5	8,524,488	1,536,201	0.1802	0.8198	42.82
8.5	6,214,197	1,102,492	0.1774	0.8226	35.10
9.5	4,591,255	1,090,935	0.2376	0.7624	28.87
10.5	3,297,806	667,638	0.2025	0.7976	22.01
11.5	1,993,801	646,576	0.3243	0.6757	17.55
12.5	1,125,882	417,088	0.3705	0.6296	11.86
13.5	682,462	191,286	0.2803	0.7197	7.47
14.5	445,418	167,622	0.3763	0.6237	5.38
15.5	178,682	27,336	0.1530	0.8470	3.36
16.5	144,684	36,543	0.2526	0.7474	2.85
17.5	108,141	10,589	0.0979	0.9021	2.13
18.5	97,552	40,074	0.4108	0.5892	1.92
19.5	57,478	12,011	0.2090	0.7910	1.13
20.5	45,467	19,252	0.4234	0.5766	0.89
21.5	26,215	1,254	0.0478	0.9522	0.51
22.5	24,961	367	0.0147	0.9853	0.49
23.5	24,594	0	0.0000	1.0000	0.48
24.5	24,594	3,721	0.1513	0.8487	0.48
25.5	20,873	0	0.0000	1.0000	0.41
26.5	20,873	0	0.0000	1.0000	0.41
27.5	20,873	384	0.0184	0.9816	0.41
28.5	20,489	0	0.0000	1.0000	0.40
29.5	20,489	0	0.0000	1.0000	0.40
30.5	20,489	3,441	0.1679	0.8321	0.40
31.5	17,048	0	0.0000	1.0000	0.33
32.5	17,048	385	0.0226	0.9774	0.33
33.5	16,663	7,823	0.4695	0.5305	0.32
34.5	8,840	8,840	1.0000		0.17

FortisBC Energy

Account #: 48400 - General Plant - Vehicles

Actual and Smooth Survivor Curves

Placement Band - 1957 - 2017   Experience Band - 1962 - 2017



FortisBC Energy

Account #: 48510 - General Plant - Vehicles

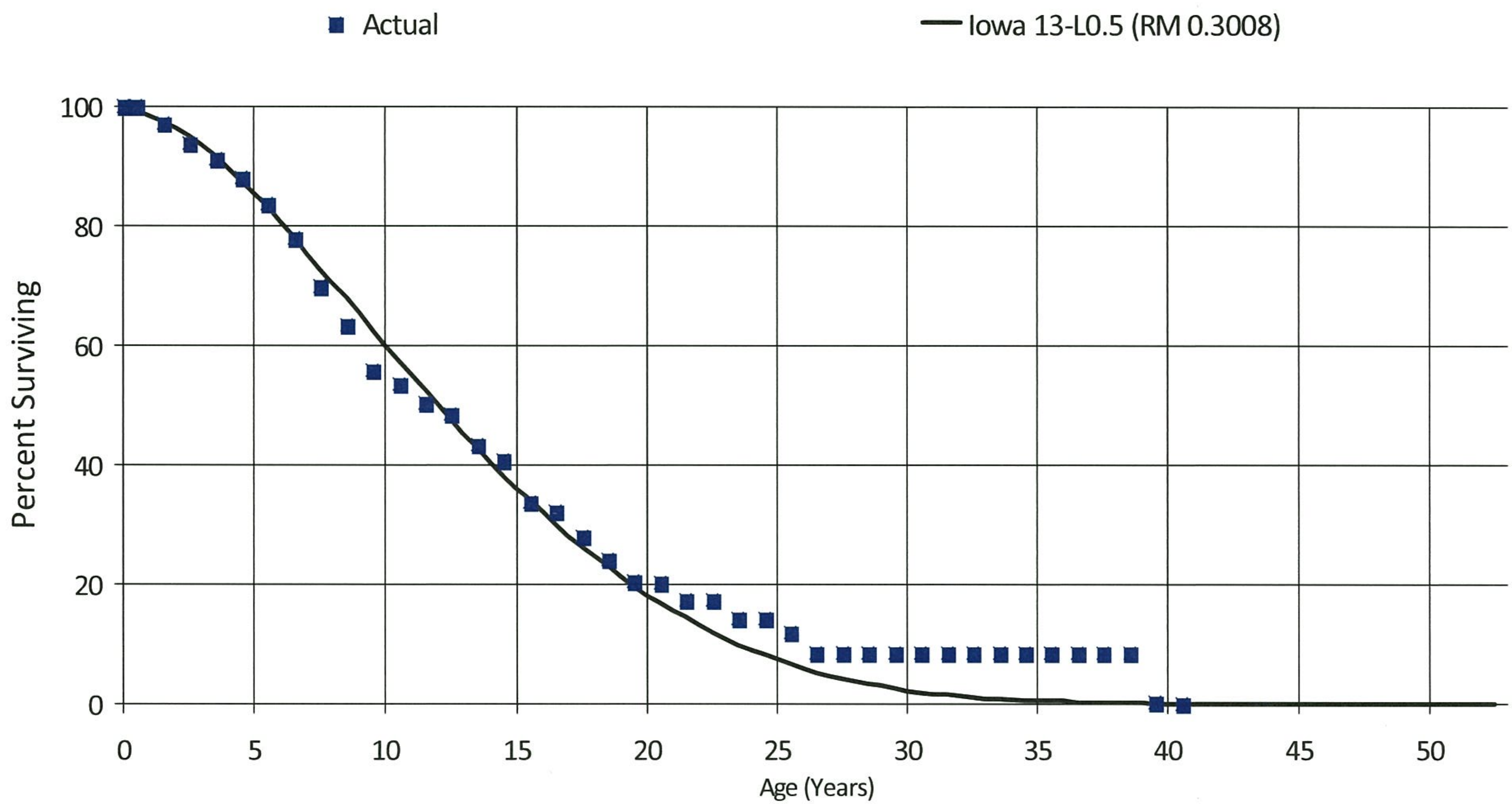
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	2,327,184	325	0.0001	0.9999	100.00
0.5	2,320,859	67,561	0.0291	0.9709	99.99
1.5	2,253,298	74,412	0.0330	0.9670	97.08
2.5	2,112,456	61,430	0.0291	0.9709	93.87
3.5	2,005,463	70,598	0.0352	0.9648	91.14
4.5	1,931,762	92,838	0.0481	0.9519	87.93
5.5	1,586,002	108,380	0.0683	0.9317	83.70
6.5	1,395,416	146,018	0.1046	0.8954	77.98
7.5	1,182,376	109,889	0.0929	0.9071	69.82
8.5	1,072,487	128,037	0.1194	0.8806	63.33
9.5	911,782	36,534	0.0401	0.9599	55.77
10.5	874,705	49,871	0.0570	0.9430	53.54
11.5	784,029	30,434	0.0388	0.9612	50.49
12.5	719,647	75,938	0.1055	0.8945	48.53
13.5	643,709	40,415	0.0628	0.9372	43.41
14.5	569,940	98,676	0.1731	0.8269	40.68
15.5	457,187	18,288	0.0400	0.9600	33.64
16.5	422,391	54,188	0.1283	0.8717	32.29
17.5	355,222	51,939	0.1462	0.8538	28.15
18.5	287,033	41,845	0.1458	0.8542	24.03
19.5	192,402	2,493	0.0130	0.9870	20.53
20.5	157,180	22,597	0.1438	0.8562	20.26
21.5	114,054	0	0.0000	1.0000	17.35
22.5	94,811	16,706	0.1762	0.8238	17.35
23.5	78,105	0	0.0000	1.0000	14.29
24.5	28,455	4,653	0.1635	0.8365	14.29
25.5	17,402	4,800	0.2758	0.7242	11.95
26.5	12,602	0	0.0000	1.0000	8.65
27.5	12,602	0	0.0000	1.0000	8.65
28.5	12,602	0	0.0000	1.0000	8.65
29.5	12,602	0	0.0000	1.0000	8.65
30.5	12,602	0	0.0000	1.0000	8.65
31.5	12,602	0	0.0000	1.0000	8.65
32.5	12,602	0	0.0000	1.0000	8.65
33.5	12,602	0	0.0000	1.0000	8.65
34.5	12,602	0	0.0000	1.0000	8.65
35.5	12,602	0	0.0000	1.0000	8.65
36.5	12,602	0	0.0000	1.0000	8.65
37.5	12,602	0	0.0000	1.0000	8.65
38.5	12,602	12,109	0.9609	0.0391	8.65
39.5	493	493	1.0005	-0.0005	0.34
40.5	0	0	0.0000	0.0000	0.00

FortisBC Energy

Account #: 48510 - General Plant - Vehicles

Actual and Smooth Survivor Curves

Placement Band - 1958 - 2017 Experience Band - 1970 - 2017



FortisBC Energy

Account #: 48520 - General Plant - Heavy Mobile Equipment

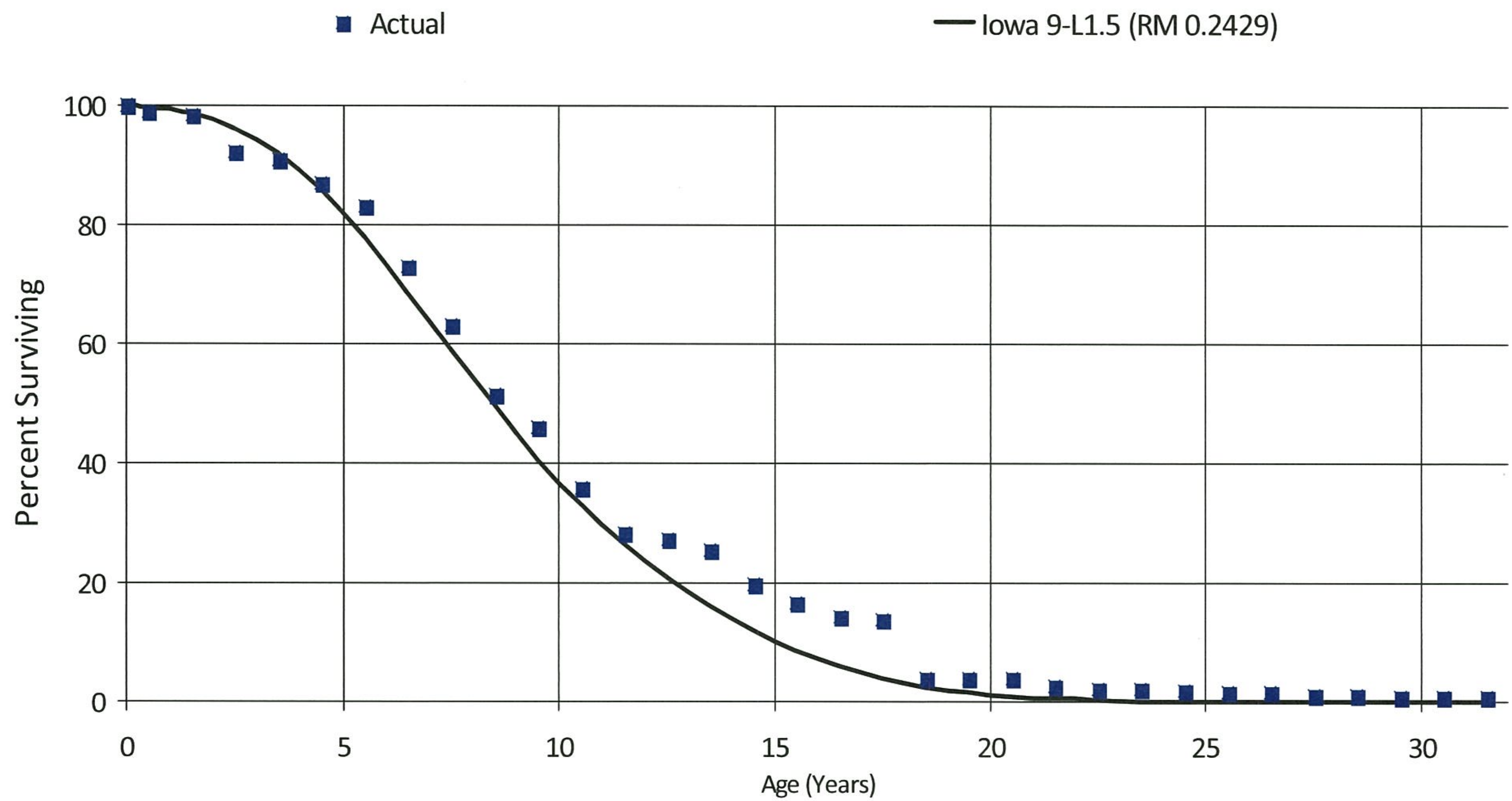
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,813,143	95,257	0.0108	0.9892	100.00
0.5	7,223,412	33,718	0.0047	0.9953	98.92
1.5	6,965,402	450,545	0.0647	0.9353	98.46
2.5	6,154,020	84,272	0.0137	0.9863	92.09
3.5	5,220,261	220,140	0.0422	0.9578	90.83
4.5	4,909,895	214,797	0.0438	0.9563	87.00
5.5	4,474,058	551,801	0.1233	0.8767	83.19
6.5	3,679,575	498,677	0.1355	0.8645	72.93
7.5	2,531,934	466,493	0.1842	0.8158	63.05
8.5	1,594,225	170,918	0.1072	0.8928	51.43
9.5	1,194,660	262,552	0.2198	0.7802	45.92
10.5	795,714	164,286	0.2065	0.7935	35.83
11.5	564,935	24,538	0.0434	0.9566	28.43
12.5	391,928	24,335	0.0621	0.9379	27.20
13.5	181,150	41,190	0.2274	0.7726	25.51
14.5	101,173	16,144	0.1596	0.8404	19.71
15.5	85,029	11,951	0.1406	0.8595	16.56
16.5	43,614	1,419	0.0325	0.9675	14.23
17.5	42,195	29,983	0.7106	0.2894	13.77
18.5	12,212	0	0.0000	1.0000	3.99
19.5	12,212	1	0.0001	0.9999	3.99
20.5	12,211	4,280	0.3505	0.6495	3.99
21.5	7,931	1,812	0.2285	0.7715	2.59
22.5	6,119	0	0.0000	1.0000	2.00
23.5	6,119	323	0.0528	0.9472	2.00
24.5	5,796	1,079	0.1862	0.8138	1.89
25.5	4,717	74	0.0157	0.9843	1.54
26.5	4,643	1,509	0.3250	0.6750	1.52
27.5	3,134	0	0.0000	1.0000	1.03
28.5	3,134	729	0.2326	0.7674	1.03
29.5	2,405	0	0.0000	1.0000	0.79
30.5	2,405	0	0.0000	1.0000	0.79
31.5	2,405	2,405	1.0000		0.79

FortisBC Energy

Account #: 48520 - General Plant - Heavy Mobile Equipment

Actual and Smooth Survivor Curves

Placement Band - 1957 - 2017 Experience Band - 1969 - 2017



SECTION 7

7 NET SALVAGE CALCULATION

FortisBC Energy Inc.

ACCOUNT 437.00 - Manufacturing Plant - Measuring and Regulating Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2001	27,548												
2002													
2003													
2004						0	0	0	0	0	0	0	0
2005								0	0	0	0	0	0
2006								0	0	0	0	0	0
2007										0	0	0	0
2008										0	0	0	0
2009											0	0	0
2010		-11,574	0			-11,574	0	-3,858	0	-2,315	0	-5,787	-42
2011		11,476	0			11,476	0	-33	0	-20	0	-33	0
2012						0	0	-33	0	-20	0	-25	0
2013						0		3,825	0	-20	0	-20	0
2014	4,012	4,903	122			4,903	122	1,634	41	961	24	801	15
2015		-18,109				-18,109				-346	-9	-1,901	-42
2016						0				-2,641	-66	-1,663	-42
2017						0				-2,641	-66	-1,478	-42
TOTAL	**31,560**	**-13,304**	**-42**	**0**	**0**	**-13,304**	**-42**						

FortisBC Energy Inc.

ACCOUNT 442.00 - LNG Plant - Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2006	1,959												
2007	17,458	-2,000	-11			-2,000	-11					-2,000	-10
2008	6,000							-667	-8			-2,000	-8
2009								-667	-6			-2,000	-8
2010										-400	-5	-2,000	-8
2011										-400	-3	-2,000	-8
2012												-2,000	-8
2013												-2,000	-8
2014												-2,000	-8
2015												-2,000	-8
2016												-2,000	-8
2017												-2,000	-8
TOTAL	**25,417**	**-2,000**	**-8**	**0**	**0**	**-2,000**	**-8**						

FortisBC Energy Inc.

ACCOUNT 443.00 - LNG Plant - Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000						0							
2001						0							
2002		-3,000				-3,000		-1,000	0			-1,000	0
2003	12,708							-1,000	-8			-1,000	-24
2004								-1,000	-8	-600	-5	-1,000	-24
2005										-600	-5	-1,000	-24
2006	44,685									-600	-1	-1,000	-5
2007	80,648											-1,000	-2
2008	1,734											-1,000	-2
2009												-1,000	-2
2010												-1,000	-2
2011												-1,000	-2
2012												-1,000	-2
2013												-1,000	-2
2014												-1,000	-2
2015												-1,000	-2
2016												-1,000	-2
2017												-1,000	-2
TOTAL	**139,775**	**-3,000**	**-2**	**0**	**0**	**-3,000**	**-2**						

FortisBC Energy Inc.

ACCOUNT 449.00 - LNG Plant - Other Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000						0							
2001	30,000												
2002													
2003	96,616												
2004	0												
2005	214,983												
2006	111,600												
2007	196,414												
2008	1,297,755	-283,859	-22	79,166	-28	-204,693	-16	-94,620	-18	-56,772	-16	-102,346	-11
2009	82,431							-94,620	-18	-56,772	-15	-102,346	-10
2010		-552				-552		-94,804	-14	-56,882	-13	-68,415	-10
2011		-8,558				-8,558		-3,037	-4	-58,594	-11	-53,451	-11
2012								-3,037	0	-58,594	-8	-53,451	-11
2013		-1,802				-1,802		-3,453	0	-2,182	-3	-43,121	-11
2014								-601	0	-2,182	0	-43,121	-11
2015	5,000							-601	-12	-2,072	-41	-43,121	-11
2016								0	0	-360	-7	-43,121	-11
2017								0	0	-360	-7	-43,121	-11
TOTAL	**2,034,799**	**-294,771**	**-14**	**79,166**	**4**	**-215,605**	**-11**						

FortisBC Energy Inc.

ACCOUNT 462.00 - Transmission Plant - Compressor Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2008	13,400												
2009	40,138												
2010	0												
2011	0	-173				-173		-58	0			-173	0
2012	349,500	-8,368	-2			-8,368	-2	-2,847	-2	-1,708	-2	-4,270	-2
2013		-1,391				-1,391		-3,311	-2	-1,986	-2	-3,311	-2
2014								-3,253	-1	-1,986	-2	-3,311	-2
2015								-464	0	-1,986	-1	-3,311	-2
2016								0	0	-1,952	-1	-3,311	-2
2017								0	0	-278	0	-3,311	-2
TOTAL	**403,038**	**-9,932**	**-2**	**0**	**0**	**-9,932**	**-2**						

FortisBC Energy Inc.

ACCOUNT 463.00 - Transmission Plant - Measuring and Regulating Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000													
2001	26,672												
2002													
2003	75,177												
2004	86,997	-15,037	-17			-15,037	-17	-5,012	-6	-3,007	-5	-15,037	-8
2005								-5,012	-6	-3,007	-5	-15,037	-8
2006	50,237							-5,012	-7	-3,007	-4	-15,037	-6
2007	40,820									-3,007	-5	-15,037	-5
2008	0									-3,007	-7	-15,037	-5
2009	4,405										0	-15,037	-5
2010	219,500	-181,034	-82			-181,034	-82	-60,345	-81	-36,207	-57	-98,035	-39
2011	10,000	4,137	41			4,137	41	-58,966	-76	-35,379	-64	-63,978	-37
2012	7,325	-7,669	-105			-7,669	-105	-61,522	-78	-36,913	-77	-49,901	-38
2013	4,641							-1,177	-16	-36,913	-75	-49,901	-38
2014								-2,556	-43	-36,913	-61	-49,901	-38
2015	32,532									-706	-5	-49,901	-36
2016										-1,534	-10	-49,901	-36
2017										0	0	-49,901	-36
TOTAL	**558,306**	**-199,602**	**-36**	**0**	**0**	**-199,602**	**-36**						

FortisBC Energy Inc.

ACCOUNT 464.00 - Transmission Plant - Other Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000													
2001	70												
2002													
2003		-15,490				-15,490		-5,163	-7,376			-15,490	-22,129
2004								-5,163	0	-3,098	-4,426	-15,490	-22,129
2005								-5,163	0	-3,098	-4,426	-15,490	-22,129
2006										-3,098	0	-15,490	-22,129
2007	6,746									-3,098	-46	-15,490	-227
2008												-15,490	-227
2009	11,730											-15,490	-84
2010												-15,490	-84
2011												-15,490	-84
2012												-15,490	-84
2013		-14,534				-14,534		-4,845	0	-2,907	-25	-15,012	-162
2014	643							-4,845	-753	-2,907	-452	-15,012	-156
2015								-4,845	-753	-2,907	-452	-15,012	-156
2016								0	0	-2,907	-452	-15,012	-156
2017								0	0	-2,907	-452	-15,012	-156
TOTAL	**19,190**	**-30,025**	**-156**	**0**	**0**	**-30,025**	**-156**						

FortisBC Energy Inc.

ACCOUNT 465.00 - Transmission Plant -Transmission Pipeline
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	719												
2001	1,219,906												
2002	657,746	-5,259	-1			-5,259	-1	-1,753	0			-5,259	0
2003	1,850,075							-1,753	0			-5,259	0
2004	682,967	-80,507	-12			-80,507	-12	-28,589	-3	-17,153	-2	-42,883	-2
2005	749,466	-36,935	-5			-36,935	-5	-39,147	-4	-24,540	-2	-40,900	-2
2006	576,912	-7,635	-1			-7,635	-1	-41,692	-6	-26,067	-3	-32,584	-2
2007	134,227							-14,857	-3	-25,015	-3	-32,584	-2
2008	67,495	-47,528	-70			-47,528	-70	-18,388	-7	-34,521	-8	-35,573	-3
2009	693,373	-752,187	-108			-752,187	-108	-266,572	-89	-168,857	-38	-155,008	-14
2010	321,324	-171,010	-53			-171,010	-53	-323,575	-90	-195,672	-55	-157,294	-16
2011	861,075	-845,270	-98			-845,270	-98	-589,489	-94	-363,199	-87	-243,291	-25
2012	3,131,294	-154,110	-5			-154,110	-5	-390,130	-27	-394,021	-39	-233,382	-19
2013	488,034	-129,806	-27			-129,806	-27	-376,395	-25	-410,477	-37	-223,025	-20
2014	4,026,900	-1,486,283	-37			-1,486,283	-37	-590,066	-23	-557,296	-32	-337,866	-24
2015	329,683	-388,897	-118			-388,897	-118	-668,328	-41	-600,873	-34	-342,119	-26
2016	585,429	-552,303	-94			-552,303	-94	-809,161	-49	-542,279	-32	-358,287	-28
2017	659,382	-103,473	-16			-103,473	-16	-348,224	-66	-532,152	-44	-340,086	-28
TOTAL	**17,036,009**	**-4,761,202**	**-28**	**0**	**0**	**-4,761,202**	**-28**						

FortisBC Energy Inc.

ACCOUNT 466.00 - Transmission Plant -Compressor Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000													
2001	10,826												
2002													
2003	57,131	-12,923	-23			-12,923	-23	-4,308	-13			-12,923	-19
2004		-2,000				-2,000	0	-4,974	-9	-2,985	-9	-7,461	-22
2005	67,044						0	-4,974	-8	-2,985	-7	-7,461	-11
2006							0	-667	-1	-2,985	-5	-7,461	-11
2007							0	0	0	-2,985	-5	-7,461	-11
2008	62,641	-3,523	-6			-3,523	-6	-1,174	-2	-1,105	-2	-6,149	-9
2009		-19,228				-19,228	0	-7,584	-12	-4,550	-7	-9,418	-19
2010	449,859	-2,280	-1			-2,280	-1	-8,344	-3	-5,006	-2	-7,991	-6
2011	714,672	-19,452	-3			-19,452	-3	-13,654	-2	-8,897	-2	-9,901	-4
2012	94,949	-5,542	-6			-5,542	-6	-9,091	-2	-10,005	-3	-9,278	-4
2013	1,329,229	-1,566	0			-1,566	0	-8,853	-1	-9,614	-1	-8,314	-2
2014	160,000		0			0	0	-2,369	0	-5,768	-1	-7,390	-2
2015	200,000	-30,786	-15			-30,786	-15	-10,784	-2	-11,469	-2	-9,730	-3
2016	568,000	-20,052	-4			-20,052	-4	-16,946	-5	-11,589	-2	-10,668	-3
2017	500,000	-20,662	-4			-20,662	-4	-23,833	-6	-14,613	-3	-11,501	-3
TOTAL	**4,214,351**	**-138,014**	**-3**	**0**	**0**	**-138,014**	**-3**						

FortisBC Energy Inc.

ACCOUNT 467.10 - Transmission Plant -Measuring and Regulating Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000													
2001	251,311												
2002	178,402												
2003	309,532												
2004	1,928,908	-77,340	-4			-77,340	-4	-25,780	-3	-15,468	-2	-77,340	-3
2005	139,586	-9,763	-7			-9,763	-7	-29,034	-4	-17,421	-3	-43,551	-3
2006	206,490	-47,392	-23			-47,392	-23	-44,831	-6	-26,899	-5	-44,831	-4
2007	275,309						0	-19,052	-9	-26,899	-5	-44,831	-4
2008	26,600	-6,720	-25			-6,720	-25	-18,037	-11	-28,243	-5	-35,304	-4
2009	231,628	-2,015	-1			-2,015	-1	-2,912	-2	-13,178	-7	-28,646	-4
2010	737,851	-4,685	-1			-4,685	-1	-4,473	-1	-12,162	-4	-24,652	-3
2011	127,225	-1,442	-1			-1,442	-1	-2,714	-1	-2,972	-1	-21,337	-3
2012	283,137	-32,994	-12			-32,994	-12	-13,040	-3	-9,571	-3	-22,794	-4
2013	214,307	-102,828	-48			-102,828	-48	-45,755	-22	-28,793	-9	-31,687	-6
2014	75,754	-43,173	-57			-43,173	-57	-59,665	-31	-37,025	-13	-32,835	-7
2015	39,528	-2,837	-7			-2,837	-7	-49,613	-45	-36,655	-25	-30,108	-7
2016	281,090						0	-15,337	-12	-36,367	-20	-30,108	-6
2017	282,595						0	-946	0	-29,768	-17	-30,108	-6
TOTAL	**5,589,255**	**-331,190**	**-6**	**0**	**0**	**-331,190**	**-6**						

FortisBC Energy Inc.

ACCOUNT 467.20 - Transmission Plant -Telemetry Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	121,625												
2001	1,877,759												
2002	0												
2003	72,642												
2004	47,359												
2005	57,476												
2006	1,337,511												
2007	300												
2008	0												
2009	7,104												
2010	0												
2011	7,903	-500	-6			-500	-6	-167	-3	-100	-3	-500	0
2012	5,000							-167	-4	-100	-2	-500	0
2013	37,706							-167	-1	-100	-1	-500	0
2014	0									-100	-1	-500	0
2015	61,761	-153	0			-153	0	-51	0	-131	-1	-326	0
2016	2,060	-25,589	-1,242			-25,589	-1,242	-8,580	-40	-5,148	-24	-8,747	-1
2017	92,022						0	-8,580	-17	-5,148	-13	-8,747	-1
TOTAL	**3,728,229**	**-26,241**	**-1**	**0**	**0**	**-26,241**	**-1**						

FortisBC Energy Inc.

ACCOUNT 468.00 - Transmission Plant -Communication Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000													
2001	13,824			9,443	68	9,443	68					9,443	68
2002								3,148	23			9,443	68
2003	211,562							3,148	3			9,443	4
2004										1,889	2	9,443	4
2005										1,889	2	9,443	4
2006	8,844											9,443	4
2007												9,443	4
2008												9,443	4
2009												9,443	4
2010	33,038											9,443	4
2011	229,969	-13,103	-6			-13,103	-6	-4,368	-3	-2,621	-2	-1,830	-1
2012								-4,368	-3	-2,621	-2	-1,830	-1
2013	225,244							-4,368	-2	-2,621	-2	-1,830	-1
2014										-2,621	-2	-1,830	-1
2015										-2,621	-1	-1,830	-1
2016	191,721											-1,830	0
2017	287,887											-1,830	0
TOTAL	**1,202,089**	**-13,103**	**-1**	**9,443**	**1**	**-3,660**	**0**						

FortisBC Energy Inc.

ACCOUNT 472.00 - Distribution Plant - Structures
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	13,168												
2001	104,190												
2002	40,060												
2003	78,668												
2004	953												
2005		-3,678				-3,678	0	-1,226	-3	-736	-1	-3,678	-2
2006	50,994	-4,276	-8			-4,276	-8	-2,652	-10	-1,591	-4	-3,977	-3
2007	54,534						0	-2,652	-5	-1,591	-3	-3,977	-2
2008	80,293	-26,516	-33			-26,516	-33	-10,264	-17	-6,894	-15	-11,490	-8
2009	35,094	-39,152	-112			-39,152	-112	-21,889	-39	-14,725	-27	-18,406	-16
2010	3,308	-243	-7			-243	-7	-21,970	-56	-14,037	-31	-14,773	-16
2011	18,155	-4,133	-23			-4,133	-23	-14,509	-77	-14,009	-37	-13,000	-16
2012		-187				-187	0	-1,521	-14	-14,046	-41	-11,169	-16
2013	92,192	-2,400	-3			-2,400	-3	-2,240	-4	-9,223	-25	-10,073	-14
2014	66,668						0	-862	-1	-1,392	-3	-10,073	-13
2015	24,177	-7,356	-30			-7,356	-30	-3,252	-5	-2,815	-6	-9,771	-13
2016	131,900	-47,671	-36			-47,671	-36	-18,342	-25	-11,523	-15	-13,561	-17
2017	79,665	-4,368	-5			-4,368	-5	-19,799	-25	-12,359	-16	-12,725	-16
TOTAL	**874,019**	**-139,980**	**-16**	**0**	**0**	**-139,980**	**-16**						

FortisBC Energy Inc.

ACCOUNT 473.00 - Distribution Plant - Services
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	1,800,475												
2001	1,098,971												
2002	2,474,792	-588,456	-24			-588,456	-24	-196,152	-11			-588,456	-11
2003	343,211	-211,987	-62			-211,987	-62	-266,814	-20			-400,222	-14
2004	2,332,842	-3,531,097	-151			-3,531,097	-151	-1,443,847	-84	-866,308	-54	-1,443,847	-54
2005	2,485,696	-3,551,042	-143			-3,551,042	-143	-2,431,375	-141	-1,576,517	-90	-1,970,646	-75
2006	13,164,951	-1,630,153	-12			-1,630,153	-12	-2,904,098	-48	-1,902,547	-46	-1,902,547	-40
2007	9,140,075						0	-1,727,065	-21	-1,784,856	-32	-1,902,547	-29
2008	3,702,055	-5,404,860	-146			-5,404,860	-146	-2,345,004	-27	-2,823,431	-46	-2,486,266	-41
2009	4,319,221	-5,440,566	-126			-5,440,566	-126	-3,615,142	-63	-3,205,324	-49	-2,908,309	-50
2010	3,171,509	-7,393,063	-233			-7,393,063	-233	-6,079,496	-163	-3,973,729	-59	-3,468,903	-63
2011	4,414,701	-12,179,045	-276			-12,179,045	-276	-8,337,558	-210	-6,083,507	-123	-4,436,697	-82
2012	5,320,515	-11,036,649	-207			-11,036,649	-207	-10,202,919	-237	-8,290,837	-198	-5,096,692	-95
2013	5,105,091	-10,120,174	-198			-10,120,174	-198	-11,111,956	-225	-9,233,900	-207	-5,553,372	-104
2014	9,452,463	-8,438,368	-89			-8,438,368	-89	-9,865,064	-149	-9,833,460	-179	-5,793,788	-102
2015	4,068,251	-8,758,515	-215			-8,758,515	-215	-9,105,685	-147	-10,106,550	-178	-6,021,844	-108
2016	3,070,108	-7,093,819	-231			-7,093,819	-231	-8,096,900	-146	-9,089,505	-168	-6,098,414	-113
2017	4,282,802	-9,156,900	-214			-9,156,900	-214	-8,336,411	-219	-8,713,555	-168	-6,302,313	-119
TOTAL	**79,747,731**	**-94,534,695**	**-119**	**0**	**0**	**-94,534,695**	**-119**						

FortisBC Energy Inc.

ACCOUNT 474.00 - Distribution Plant - Meter and Regulator
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	95,683						0						
2001	2,428,481						0						
2002	6,270,257	-53,023	-1			-53,023	-1	-17,674	-1			-53,023	-1
2003	3,267,469	-14,989	0			-14,989	0	-22,671	-1			-34,006	-1
2004	4,930,968	-247,468	-5			-247,468	-5	-105,160	-2	-63,096	-2	-105,160	-2
2005	6,813,560	-217,139	-3			-217,139	-3	-159,865	-3	-106,524	-2	-133,155	-2
2006	8,240,670	-211,256	-3			-211,256	-3	-225,288	-3	-148,775	-3	-148,775	-2
2007	5,860,519						0	-142,798	-2	-138,170	-2	-148,775	-2
2008	7,010,448	-900,663	-13			-900,663	-13	-370,639	-5	-315,305	-5	-274,090	-4
2009	7,349,546	-1,320,731	-18	12,236	0	-1,308,495	-18	-740,464	-11	-529,958	-8	-421,862	-6
2010	17,660,406	-2,490,045	-14			-2,490,045	-14	-1,570,479	-15	-984,539	-11	-680,385	-8
2011	68,245	-2,717,111	-3,981			-2,717,111	-3,981	-2,175,962	-26	-1,485,710	-20	-906,688	-12
2012	1,078,773	-2,994,079	-278			-2,994,079	-278	-2,733,745	-44	-2,084,526	-31	-1,115,427	-16
2013	851,997	-3,478,502	-408			-3,478,502	-408	-3,063,231	-460	-2,600,093	-48	-1,330,252	-20
2014	899,228	-3,679,458	-409			-3,679,458	-409	-3,384,013	-359	-3,071,839	-75	-1,526,019	-25
2015	1,666,771	-4,528,781	-272			-4,528,781	-272	-3,895,580	-342	-3,479,586	-381	-1,757,001	-31
2016	85,085	-5,146,762	-6,049			-5,146,762	-6,049	-4,451,667	-504	-3,965,516	-433	-1,999,126	-38
2017	9,228,784	-4,244,562	-46			-4,244,562	-46	-4,640,035	-127	-4,215,613	-166	-2,148,822	-38
TOTAL	**83,806,890**	**-32,244,567**	**-38**	**12,236**	**0**	**-32,232,331**	**-38**						

FortisBC Energy Inc.

ACCOUNT 475.00 - Distribution Plant - Mains
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	4,430,340												
2001	485,250												
2002	1,000,236	-63,210	-6			-63,210	-6	-21,070	-1			-63,210	-1
2003	96,226	-23,024	-24			-23,024	-24	-28,745	-5			-43,117	-1
2004	424,865	-364,611	-86			-364,611	-86	-150,282	-30	-90,169	-7	-150,282	-7
2005	816,133	-532,849	-65			-532,849	-65	-306,828	-69	-196,739	-35	-245,923	-14
2006	2,701,842	-139,634	-5			-139,634	-5	-345,698	-26	-224,666	-22	-224,666	-11
2007	2,163,435						0	-224,161	-12	-212,023	-17	-224,666	-9
2008	2,444,452	-474,834	-19			-474,834	-19	-204,823	-8	-302,386	-18	-266,360	-11
2009	3,350,956	-592,027	-18			-592,027	-18	-355,620	-13	-347,869	-15	-312,884	-12
2010	1,212,065	-531,511	-44			-531,511	-44	-532,791	-23	-347,601	-15	-340,212	-14
2011	1,414,525	-766,407	-54			-766,407	-54	-629,981	-32	-472,956	-22	-387,567	-17
2012	1,563,776	-1,311,699	-84			-1,311,699	-84	-869,872	-62	-735,295	-37	-479,980	-22
2013	1,683,240	-620,950	-37			-620,950	-37	-899,685	-58	-764,519	-41	-492,796	-23
2014	4,103,990	-1,357,998	-33			-1,357,998	-33	-1,096,882	-45	-917,713	-46	-564,896	-24
2015	1,378,697	-985,915	-72			-985,915	-72	-988,288	-41	-1,008,594	-50	-597,282	-27
2016	632,513	-915,916	-145			-915,916	-145	-1,086,610	-53	-1,038,496	-55	-620,042	-29
2017	2,116,939	-852,928	-40			-852,928	-40	-918,253	-67	-946,742	-48	-635,568	-30
TOTAL	**32,019,479**	**-9,533,513**	**-30**	**0**	**0**	**-9,533,513**	**-30**						

FortisBC Energy Inc.

ACCOUNT 476.00 - Distribution Plant - NGV Fuel Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	7,475,766												
2001	91												
2002													
2003													
2004													
2005													
2006													
2007													
2008													
2009													
2010													
2011													
2012													
2013													
2014													
2015													
2016	771,459	-5,250	-1		0	-5,250	-1	-1,750	0	-1,050	0	-5,250	0
2017								-1,750	0	-1,050	0	-5,250	0
TOTAL	**8,247,316**	**-5,250**	**0**	**0**	**0**	**-5,250**	**0**						

FortisBC Energy Inc.

ACCOUNT 477.10 - Distribution Plant - Measuring and Regulating
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	346,633												
2001	2,262,537												
2002	799,436	-43,803	-5			-43,803	-5	-14,601	-1			-43,803	-1
2003	1,025,334	-45,686	-4			-45,686	-4	-29,830	-2			-44,745	-2
2004	63,872	-158,470	-248			-158,470	-248	-82,653	-13	-49,592	-6	-82,653	-6
2005	527,761	-40,275	-8			-40,275	-8	-81,477	-15	-57,647	-6	-72,059	-6
2006	1,045,949	-34,302	-3			-34,302	-3	-77,682	-14	-64,507	-9	-64,507	-5
2007	563,389						0	-24,859	-3	-55,747	-9	-64,507	-5
2008	901,908	-356,214	-39			-356,214	-39	-130,172	-16	-117,852	-19	-113,125	-9
2009	521,037	-104,228	-20			-104,228	-20	-153,480	-23	-107,004	-15	-111,854	-10
2010	277,280	-23,126	-8			-23,126	-8	-161,189	-28	-103,574	-16	-100,763	-10
2011	392,040	-42,042	-11			-42,042	-11	-56,465	-14	-105,122	-20	-94,238	-10
2012	1,101,785	-59,878	-5			-59,878	-5	-41,682	-7	-117,098	-18	-90,802	-9
2013	422,122	-50,946	-12			-50,946	-12	-50,955	-8	-56,044	-10	-87,179	-9
2014	483,083	-21,385	-4			-21,385	-4	-44,070	-7	-39,475	-7	-81,696	-9
2015	517,505	-72,527	-14			-72,527	-14	-48,286	-10	-49,356	-8	-80,991	-9
2016	662,008	-208,155	-31			-208,155	-31	-100,689	-18	-82,578	-13	-90,074	-11
2017	812,103	-276,306	-34			-276,306	-34	-185,663	-28	-125,864	-22	-102,490	-12
TOTAL	**12,725,783**	**-1,537,344**	**-12**			**-1,537,344**	**-12**						

FortisBC Energy Inc.

ACCOUNT 477.20 - Distribution Plant -Telemetry
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	17,499												
2001	80,431												
2002	251,623												
2003	68,932												
2004		-227				-227	0	-76	0	-45	0	-227	0
2005							0	-76	0	-45	0	-227	0
2006	1,008	-2,382	-236			-2,382	-236	-870	-86	-522	0	-1,305	-1
2007	32,413						0	-794	-5	-522	-2	-1,305	-1
2008	5,000						0	-794	-6	-522	-4	-1,305	-1
2009	54,840						0	0	0	-476	-2	-1,305	-1
2010	3,222						0	0	0	-476	-2	-1,305	-1
2011	149,241	-831	-1			-831	-1	-277	0	-166	0	-1,147	-1
2012	85,025	-15	0			-15	0	-282	0	-169	0	-864	0
2013	9,941	-11,533	-116			-11,533	-116	-4,126	-5	-2,476	-4	-2,997	-2
2014	108,594						0	-3,849	-6	-2,476	-3	-2,997	-2
2015	98,393	-9,533	-10			-9,533	-10	-7,022	-10	-4,382	-5	-4,087	-3
2016	147,084	-8,947	-6			-8,947	-6	-6,160	-5	-6,006	-7	-4,781	-3
2017	49,210						0	-6,160	-6	-6,003	-7	-4,781	-3
TOTAL	**1,162,458**	**-33,467**	**-3**	**0**	**0**	**-33,467**	**-3**						

FortisBC Energy Inc.

ACCOUNT 478.10 - Distribution Plant -Meters
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	679,275												
2001	2,117,588												
2002	3,437,049												
2003	2,018,918												
2004	2,729,515			78,811	3	78,811						78,811	1
2005	4,879,690											78,811	0
2006	3,821,305											78,811	0
2007	3,118,099											78,811	0
2008	4,782,171	69,432	1	284,774	6	354,206	7	118,069	3	86,603	2	216,508	2
2009	4,143,930	-71,292	-2	66,136	2	-5,156	0	116,350	3	69,810	2	142,620	1
2010	6,433,600	-147,607	-2	136,306	2	-11,301	0	112,583	3	67,550	2	104,140	1
2011	4,759,675	-135,914	-3	241,924	5	106,011	2	29,851	1	88,752	2	104,514	1
2012	8,509,300	-117,023	-1	172,166	2	55,143	1	49,951	1	99,781	2	96,286	1
2013	8,250,035	-211,511	-3	360,326	4	148,815	2	103,323	2	58,702	1	103,790	1
2014	6,633,512	-153,078	-2	329,250	5	176,172	3	126,710	2	94,968	1	112,838	1
2015	6,571,396	33,108	1			33,108	1	119,365	2	103,850	1	103,979	1
2016	6,771,458	90,997	1			90,997	1	100,092	1	100,847	1	102,681	1
2017	6,005,393	91,232	2			91,232	2	71,779	1	108,065	2	101,640	1
TOTAL	**85,661,908**	**-551,656**	**-1**	**1,669,693**	**2**	**1,118,038**	**1**						

FortisBC Energy Inc.

ACCOUNT 482.10 - General Plant - Structures (Frame)
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	1,255,720												
2001	5,565,513												
2002	40,469	-613	-2			-613	-2	-204	0			-613	0
2003	87,243						0	-204	0			-613	0
2004				800		800	0	62	0	37	0	93	0
2005	1,200						0	267	1	37	0	93	0
2006	28,003						0	267	2	37	0	93	0
2007	6,655						0	0	0	160	1	93	0
2008	258,882	-11,410	-4			-11,410	-4	-3,803	-4	-2,122	-3	-3,741	0
2009	1,909	-450	-24			-450	-24	-3,953	-4	-2,372	-4	-2,918	0
2010	4,888							-3,953	-4	-2,372	-4	-2,918	0
2011	154,534							-150	0	-2,372	-3	-2,918	0
2012								0	0	-2,372	-2	-2,918	0
2013								0	0	-90	0	-2,918	0
2014								0	0	0	0	-2,918	0
2015		-128,381				-128,381		-42,794	0	-25,676	-17	-28,011	-2
2016	113,059	-149,152	-132			-149,152	-132	-92,511	-82	-55,507	-49	-48,201	-4
2017	165,136	-6,163	-4			-6,163	-4	-94,565	-68	-56,739	-41	-42,196	-4
TOTAL	**7,683,211**	**-296,169**	**-4**	**800**	**0**	**-295,369**	**-4**						

FortisBC Energy Inc.

ACCOUNT 482.20 - General Plant - Structures (Masonry)
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	876,365												
2001	213,291												
2002	5,545												
2003	60,624												
2004				800		800		267	1			800	0
2005								267	0			800	0
2006	106,637							267	0			800	0
2007	26,805							0	0			800	0
2008	511,877	-134,252	-26			-134,252	-26	-44,751	-21	-26,690	-12	-66,726	-7
2009	40,000	-100,978	-252			-100,978	-252	-78,410	-41	-47,046	-27	-78,143	-13
2010								-78,410	-28	-47,046	-27	-78,143	-13
2011								-33,659	-84	-47,046	-24	-78,143	-13
2012		45				45		15	0	-47,037	-17	-58,596	-13
2013		-547				-547		-167	0	-20,296	-51	-46,986	-13
2014								-167	0	-100	0	-46,986	-13
2015		-53,733				-53,733		-18,093	0	-10,847	0	-48,111	-16
2016	339,032						0	-17,911	-5	-10,847	-3	-48,111	-13
2017	377,325						0	-17,911	-5	-10,856	-3	-48,111	-11
TOTAL	**2,557,501**	**-289,465**	**-11**	**800**	**0**	**-288,665**	**-11**						

FortisBC Energy Inc.

ACCOUNT 484.00 - General Plant - Vehicles
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	1,582,820												
2001	34,001												
2002	239,632												
2003	30,578												
2004	260,925												
2005	14,890												
2006	7,381												
2007	93,297												
2008	40,268	7,617	19	4,000	10	11,617	29	3,872	8	2,323	3	11,617	1
2009	32,635	-1,081	-3	13,825	42	12,744	39	8,120	15	4,872	13	12,180	1
2010	169,164			29,791	18	29,791	18	18,050	22	10,830	16	18,050	2
2011	872,023						0	14,178	4	10,830	4	18,050	2
2012	580,467						0	9,930	2	10,830	3	18,050	1
2013	300,515						0	0	0	8,507	2	18,050	1
2014	376,446			145,085	39	145,085	39	48,362	12	34,975	8	49,809	4
2015	681,831	184,494	27			184,494	27	109,860	24	65,916	12	76,746	7
2016	429,629	132,603	31			132,603	31	154,061	31	92,436	20	86,056	9
2017	166,615	254,696	153			254,696	153	190,597	45	143,376	37	110,147	13
TOTAL	**5,913,118**	**578,328**	**10**	**192,701**	**3**	**771,029**	**13**						

FortisBC Energy Inc.

ACCOUNT 485.10 - General Plant - Heavy Work Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2000	13,523												
2001													
2002	6,318												
2003													
2004													
2005													
2006	26,600												
2007													
2008								0	0	2	0		
2009								0	0	2	0		
2010	12,429							0	0	2	0		
2011	45,146							0	0	2	0		
2012	46,290							0	0	2	0		
2013	66,482							0	0	2	0		
2014	24,491							0	0	2	0		
2015						0		0	0	2	0	0	0
2016	63,971		0	6,997		6,997	11	2,332	5	1,401	3	3,499	2
2017						0		2,332	4	1,401	3	2,332	2
TOTAL	**305,250**	**0**	**0**	**6,997**	**2**	**6,997**	**2**						

FortisBC Energy Inc.

ACCOUNT 485.20 - General Plant - Radio Equipment
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
2005	4,280												
2006	35,407												
2007	1												
2008								0	0	2	0		
2009								0	0	2	0		
2010	0							0	0	2	0		
2011	5,699							0	0	2	0		
2012	19,035							0	0	2	0		
2013	79,630							0	0	2	0		
2014								0	0	2	0		
2015						0		0	0	2	0	0	0
2016	1,758		0			0	0	0	0	2	0	0	0
2017						0		0	0	2	0	0	0
TOTAL	**145,810**	**0**	**0**	**0**	**0**	**0**	**0**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATION

FortisBC Energy Inc.

Account #: 40101 - INTANGIBLE PLANT - FRANCHISES AND CONSENTS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1987	8,238.78	6,179	8,239	1.0000	0	10.00	0	30.0
1990	1,082.17	730	1,042	0.9627	40	13.00	3	27.0
1991	186,139.77	120,991	172,560	0.9270	13,579	14.00	970	26.0
1992	2,554.74	1,597	2,277	0.8914	277	15.00	18	25.0
2009	99,236.40	19,847	28,307	0.2852	70,930	32.00	2,217	8.0
TOTAL	297,251.86	149,344	212,425		84,827		3,208	

COMPOSITE ANNUAL ACCRUAL RATE	1.08%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.71
COMPOSITE AVERAGE AGE (YEARS)	20.10
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	19.90

FortisBC Energy Inc.

Account #: 40211 - INTANGIBLE PLANT - PLANT ACQUISITIONS AND ADJUSTMENTS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 40
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	62,456.53	12,491	62,457	1.0000	0	32.00	0	8.0
TOTAL	62,456.53	12,491	62,457		0		0	

** Allocated Booked Amount not equal to summation **

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	8.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	32.00

FortisBC Energy Inc.

Account #: 44200 - LNG PLANT - STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L2
ASL: 25
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	1,453,071.43	1,037,578	1,344,891	0.9256	253,487	8.77	28,899	29.0
1991	1,924.79	1,313	1,702	0.8842	415	9.50	44	26.0
1992	110,426.95	74,167	96,134	0.8706	25,335	9.74	2,602	25.0
1993	8,093.70	5,350	6,935	0.8568	1,968	9.98	197	24.0
1994	84,561.94	54,986	71,272	0.8428	21,746	10.22	2,127	23.0
1995	132,581.49	84,733	109,830	0.8284	36,010	10.47	3,438	22.0
1996	42,779.92	26,842	34,792	0.8133	12,266	10.74	1,142	21.0
1997	246,113.24	151,369	196,201	0.7972	74,523	11.02	6,761	20.0
1998	396,745.70	238,711	309,414	0.7799	127,007	11.33	11,214	19.0
1999	133,892.83	78,608	101,891	0.7610	45,391	11.66	3,894	18.0
2000	318,749.06	182,021	235,932	0.7402	114,692	12.02	9,540	17.0
2001	94,819.16	52,459	67,996	0.7171	36,305	12.43	2,922	16.0
2002	36,534.09	19,489	25,261	0.6914	14,927	12.88	1,159	15.0
2003	704,255.73	360,130	466,794	0.6628	307,887	13.38	23,014	14.0
2004	16,996.28	8,274	10,725	0.6310	7,971	13.94	572	13.0
2005	788,457.87	362,437	469,785	0.5958	397,519	14.55	27,316	12.0
2006	13,612.01	5,852	7,585	0.5573	7,388	15.23	485	11.0
2007	270,602.22	107,621	139,496	0.5155	158,166	15.96	9,909	10.0
2008	30,361.26	11,033	14,300	0.4710	19,097	16.74	1,141	9.0
2009	0.84	0	0	0.4244	1	17.56	0	8.0
2010	74,883.19	21,737	28,176	0.3763	54,196	18.40	2,945	7.0
2014	206,919.61	26,924	34,898	0.1687	192,714	22.04	8,743	3.0
2015	15,121.82	1,322	1,713	0.1133	14,921	23.01	648	2.0
2016	26,945.83	1,183	1,534	0.0569	28,107	24.00	1,171	1.0
2017	961.40	0	0	0.0000	1,058	25.00	42	0.0

FortisBC Energy Inc.

Account #: 44200 - LNG PLANT - STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L2
ASL: 25
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	5,209,412.36	2,914,137	3,777,256		1,953,098		149,927	

COMPOSITE ANNUAL ACCRUAL RATE	2.88%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.73
COMPOSITE AVERAGE AGE (YEARS)	18.65
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.29

FortisBC Energy Inc.

Account #: 44201 - LNG PLANT - STRUCTURES - MT. HAYES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L2
ASL: 25
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	17,258,994.49	4,349,017	4,585,791	0.2657	14,399,103	19.27	747,111	6.0
2013	22,616.08	3,887	4,099	0.1812	20,779	21.09	985	4.0
2014	26,128.07	3,400	3,585	0.1372	25,156	22.04	1,141	3.0
2015	858,751.90	75,050	79,136	0.0922	865,491	23.01	37,608	2.0
2016	504,223.29	22,142	23,348	0.0463	531,298	24.00	22,136	1.0
2017	368,007.45	0	0	0.0000	404,808	25.00	16,192	0.0
TOTAL	19,038,721.28	4,453,495	4,695,958		16,246,635		825,172	

COMPOSITE ANNUAL ACCRUAL RATE	4.33%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	5.56
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	19.68

FortisBC Energy Inc.

Account #: 44300 - LNG PLANT - EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S4
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	9,052,020.29	7,647,914	8,687,274	0.9597	2,175,150	11.84	183,756	29.0
1991	29,946.64	23,050	26,183	0.8743	9,753	14.34	680	26.0
1993	62,452.26	44,658	50,728	0.8123	24,215	16.16	1,498	24.0
1996	393,472.04	247,400	281,022	0.7142	191,145	19.04	10,038	21.0
1997	184,604.19	110,632	125,667	0.6807	95,859	20.02	4,787	20.0
1998	102,424.92	58,342	66,271	0.6470	56,639	21.01	2,695	19.0
1999	746,733.77	403,088	457,868	0.6132	438,212	22.01	19,913	18.0
2000	81,921.07	41,772	47,449	0.5792	50,857	23.00	2,211	17.0
2001	102,295.11	49,097	55,770	0.5452	66,984	24.00	2,791	16.0
2002	5,304,069.89	2,386,741	2,711,102	0.5111	3,653,782	25.00	146,148	15.0
2003	183,540.37	77,086	87,562	0.4771	132,687	26.00	5,103	14.0
2004	198,778.25	77,523	88,059	0.4430	150,475	27.00	5,573	13.0
2006	51,498.10	16,994	19,304	0.3748	42,494	29.00	1,465	11.0
2007	260.44	78	89	0.3408	224	30.00	7	10.0
2011	4,599.00	828	940	0.2045	4,578	34.00	135	6.0
2015	67,683.59	4,061	4,613	0.0682	76,607	38.00	2,016	2.0
2016	138,728.33	4,162	4,727	0.0341	161,747	39.00	4,147	1.0
2017	8,726.97	0	0	0.0000	10,472	40.00	262	0.0
TOTAL	16,713,755.23	11,193,427	12,714,626		7,341,880		393,226	

COMPOSITE ANNUAL ACCRUAL RATE	2.35%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.76
COMPOSITE AVERAGE AGE (YEARS)	22.78
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	17.68

FortisBC Energy Inc.

Account #: 44305 - LNG PLANT - EQUIPMENT - MT. HAYES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R5
ASL: 60
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	60,103,831.61	7,212,988	6,804,053	0.1132	65,320,545	54.00	1,209,650	6.0
2015	33,011.11	1,321	1,246	0.0377	38,367	58.00	662	2.0
2016	155,710.19	3,116	2,939	0.0189	183,913	59.00	3,117	1.0
2017	367,184.08	3	3	0.0000	440,618	60.00	7,344	0.0
TOTAL	60,659,736.99	7,217,427	6,808,241		65,983,443		1,220,772	

COMPOSITE ANNUAL ACCRUAL RATE	2.01%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.11
COMPOSITE AVERAGE AGE (YEARS)	5.95
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	54.05

FortisBC Energy Inc.

Account #: 44810 - LNG PLANT - PIPING

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	11,486,805.95	1,846,139	1,916,163	0.1668	10,719,323	34.16	313,837	6.0
2015	45,714.55	2,469	2,563	0.0561	47,723	38.04	1,255	2.0
2017	900,511.97	0	0	0.0000	990,563	40.00	24,764	0.0
TOTAL	12,433,032.47	1,848,608	1,918,726		11,757,610		339,856	

COMPOSITE ANNUAL ACCRUAL RATE	2.73%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.15
COMPOSITE AVERAGE AGE (YEARS)	5.55
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	34.59

FortisBC Energy Inc.

Account #: 44820 - LNG PLANT - PRE-TREATMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 25
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	28,709,484.95	7,310,082	7,651,194	0.2665	23,929,239	19.21	1,245,463	6.0
2015	284,517.80	24,534	25,679	0.0903	287,290	23.04	12,469	2.0
2016	230,594.41	9,970	10,436	0.0453	243,218	24.02	10,127	1.0
2017	17,335.95	0	0	0.0000	19,070	25.00	763	0.0
TOTAL	29,241,933.11	7,344,587	7,687,309		24,478,817		1,268,822	

COMPOSITE ANNUAL ACCRUAL RATE	4.34%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.26
COMPOSITE AVERAGE AGE (YEARS)	5.92
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	19.29

FortisBC Energy Inc.

Account #: 44830 - LNG PLANT - LIQUEFACTION EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	28,709,484.95	5,033,604	4,866,509	0.1695	29,584,873	34.16	866,177	6.0
2015	122,976.78	7,246	7,006	0.0570	140,566	38.04	3,696	2.0
2017	50,655.29	0	0	0.0000	60,786	40.00	1,520	0.0
TOTAL	28,883,117.02	5,040,850	4,873,515		29,786,225		871,392	

COMPOSITE ANNUAL ACCRUAL RATE	3.02%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	5.97
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	34.18

FortisBC Energy Inc.

Account #: 44840 - LNG PLANT - SEND OUT EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	22,957,011.22	3,360,365	3,822,929	0.1665	21,429,784	34.68	617,979	6.0
2015	360,916.00	17,874	20,334	0.0563	376,673	38.20	9,861	2.0
2016	35,308.30	877	998	0.0283	37,841	39.10	968	1.0
2017	201,840.73	0	0	0.0000	222,025	40.00	5,551	0.0
TOTAL	23,555,076.25	3,379,116	3,844,261		22,066,323		634,358	

COMPOSITE ANNUAL ACCRUAL RATE	2.69%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.16
COMPOSITE AVERAGE AGE (YEARS)	5.88
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	34.78

FortisBC Energy Inc.

Account #: 44850 - LNG PLANT - SUBSTATION AND ELECTRICAL

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	21,640,920.67	3,455,695	3,663,914	0.1693	22,305,191	34.68	643,223	6.0
2015	107,598.77	5,813	6,163	0.0573	122,955	38.20	3,219	2.0
2017	42,423.46	0	0	0.0000	50,908	40.00	1,273	0.0
TOTAL	21,790,942.90	3,461,508	3,670,077		22,479,054		647,715	

COMPOSITE ANNUAL ACCRUAL RATE	2.97%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.17
COMPOSITE AVERAGE AGE (YEARS)	5.97
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	34.70

FortisBC Energy Inc.

Account #: 44860 - LNG PLANT - CONTROL ROOM

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	5,899,221.20	2,221,983	2,561,883	0.4343	3,337,338	9.35	356,929	6.0
2015	232,036.04	30,179	34,795	0.1500	197,241	13.05	15,115	2.0
2016	222,839.89	14,570	16,799	0.0754	206,041	14.02	14,697	1.0
TOTAL	6,354,097.13	2,266,731	2,613,477		3,740,620		386,741	

COMPOSITE ANNUAL ACCRUAL RATE	6.09%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.41
COMPOSITE AVERAGE AGE (YEARS)	5.68
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	9.65

FortisBC Energy Inc.

Account #: 44900 - LNG PLANT - OTHER EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 27
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	5,536,937.17	5,055,560	5,339,342	0.9643	751,289	4.59	163,733	29.0
1991	554,462.83	475,687	502,389	0.9061	107,520	5.94	18,095	26.0
1992	562,926.89	470,985	497,423	0.8836	121,796	6.46	18,844	25.0
1993	2,336,891.81	1,902,288	2,009,069	0.8597	561,512	7.02	79,994	24.0
1994	195,647.09	154,564	163,240	0.8344	51,972	7.61	6,831	23.0
1995	2,871,517.51	2,195,900	2,319,161	0.8076	839,508	8.23	102,010	22.0
1996	801,912.30	591,995	625,225	0.7797	256,878	8.88	28,928	21.0
1997	81,130.05	57,653	60,889	0.7505	28,354	9.56	2,967	20.0
1998	18,560.60	12,657	13,368	0.7202	7,049	10.26	687	19.0
1999	644,297.54	420,283	443,874	0.6889	264,853	10.99	24,102	18.0
2000	964,847.19	599,908	633,582	0.6567	427,750	11.74	36,440	17.0
2001	21,505.53	12,695	13,408	0.6235	10,248	12.51	819	16.0
2002	357,001.87	199,237	210,421	0.5894	182,281	13.30	13,704	15.0
2003	1,799,856.75	945,014	998,060	0.5545	981,783	14.11	69,569	14.0
2004	32,356.13	15,895	16,787	0.5188	18,805	14.94	1,259	13.0
2005	198,987.18	90,881	95,983	0.4824	122,903	15.79	7,784	12.0
2006	305,886.62	128,930	136,168	0.4452	200,308	16.65	12,028	11.0
2007	359,087.89	138,470	146,243	0.4073	248,754	17.53	14,186	10.0
2008	4,157,417.12	1,451,361	1,532,830	0.3687	3,040,329	18.43	164,956	9.0
2009	1,849,724.98	577,133	609,529	0.3295	1,425,168	19.34	73,684	8.0
2010	627,350.21	172,136	181,798	0.2898	508,287	20.27	25,082	7.0
2011	64,069.35	15,137	15,987	0.2495	54,489	21.20	2,570	6.0
2012	668,179.44	132,102	139,518	0.2088	595,480	22.15	26,887	5.0
2013	26,659.00	4,232	4,470	0.1677	24,855	23.10	1,076	4.0
2014	88,599.02	10,584	11,179	0.1262	86,280	24.07	3,585	3.0
2015	152,230.67	12,160	12,842	0.0844	154,611	25.04	6,175	2.0
2016	442,339.16	17,712	18,706	0.0423	467,867	26.02	17,983	1.0
2017	19,526.33	0	0	0.0000	21,479	27.00	796	0.0

FortisBC Energy Inc.

Account #: 44900 - LNG PLANT - OTHER EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 27
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	25,739,908.23	15,861,161	16,751,489		11,562,410		924,772	

COMPOSITE ANNUAL ACCRUAL RATE	3.59%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.65
COMPOSITE AVERAGE AGE (YEARS)	17.94
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	11.87

FortisBC Energy Inc.

Account #: 44901 - LNG PLANT - OTHER EQUIPMENT - MT. HAYES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 33
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	33,241.73	6,455	4,853	0.1460	31,713	27.17	1,167	6.0
2014	2,925,678.44	286,431	215,359	0.0736	3,002,887	30.06	99,887	3.0
2015	2,273,993.41	148,754	111,844	0.0492	2,389,549	31.04	76,989	2.0
2016	359,107.68	11,769	8,848	0.0246	386,170	32.02	12,061	1.0
2017	8,415.58	0	0	0.0000	9,257	33.00	281	0.0
TOTAL	5,600,436.84	453,409	340,905		5,819,576		190,385	

COMPOSITE ANNUAL ACCRUAL RATE	3.40%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.06
COMPOSITE AVERAGE AGE (YEARS)	2.48
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	30.57

FortisBC Energy Inc.

Account #: 46200 - TRANSMISSION PLANT - COMPRESSOR STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S4
ASL: 30
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1973	215,401.10	212,618	212,477	0.9864	9,386	1.25	7,508	44.0
1975	6,158.28	6,025	6,021	0.9778	322	1.50	214	42.0
1977	67.03	65	65	0.9681	4	1.78	2	40.0
1978	5,916.53	5,699	5,695	0.9625	399	1.95	205	39.0
1980	614.64	584	584	0.9503	49	2.30	21	37.0
1982	1,246.15	1,167	1,166	0.9357	117	2.73	43	35.0
1984	895.28	823	822	0.9182	100	3.24	31	33.0
1988	2,555.92	2,229	2,227	0.8715	405	4.60	88	29.0
1989	2,559.08	2,193	2,192	0.8566	444	5.03	88	28.0
1990	31,298.71	26,313	26,296	0.8401	5,942	5.51	1,078	27.0
1991	1,852,637.56	1,523,925	1,522,913	0.8220	385,304	6.04	63,775	26.0
1992	251,036.89	201,502	201,368	0.8021	57,200	6.62	8,639	25.0
1993	1,182,706.65	923,643	923,030	0.7804	295,158	7.25	40,691	24.0
1994	1,447,030.17	1,095,844	1,095,117	0.7568	395,324	7.94	49,773	23.0
1995	4,624,628.27	3,384,390	3,382,144	0.7313	1,381,223	8.68	159,038	22.0
1996	432,974.21	305,061	304,859	0.7041	141,105	9.48	14,887	21.0
1997	394,931.89	266,835	266,657	0.6752	140,122	10.32	13,576	20.0
1998	3,329,048.96	2,148,250	2,146,824	0.6449	1,282,096	11.20	114,425	19.0
1999	2,550,221.28	1,565,250	1,564,211	0.6134	1,062,517	12.12	87,643	18.0
2000	4,347,881.76	2,527,272	2,525,594	0.5809	1,952,724	13.07	149,406	17.0
2001	785,677.98	430,605	430,319	0.5477	378,929	14.04	26,995	16.0
2002	1,928,474.22	991,988	991,329	0.5140	994,999	15.02	66,255	15.0
2003	111,375.93	53,505	53,469	0.4801	61,248	16.01	3,826	14.0
2004	167,721.21	74,842	74,792	0.4459	97,961	17.00	5,761	13.0
2006	52,844.97	19,957	19,944	0.3774	34,486	19.00	1,815	11.0
2007	1,661,264.19	570,363	569,985	0.3431	1,141,117	20.00	57,056	10.0
2008	176,799.50	54,631	54,595	0.3088	127,509	21.00	6,072	9.0
2009	449,756.30	123,533	123,451	0.2745	339,798	22.00	15,445	8.0

FortisBC Energy Inc.

Account #: 46200 - TRANSMISSION PLANT - COMPRESSOR STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S4
ASL: 30
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	225,317.46	54,151	54,115	0.2402	177,962	23.00	7,737	7.0
2011	566,520.02	116,703	116,626	0.2059	466,890	24.00	19,454	6.0
2012	1,931,739.12	331,615	331,395	0.1716	1,658,296	25.00	66,332	5.0
2013	662,072.62	90,925	90,864	0.1372	591,071	26.00	22,733	4.0
2014	157,689.11	16,242	16,231	0.1029	146,189	27.00	5,414	3.0
2015	422,578.72	29,017	28,998	0.0686	406,258	28.00	14,509	2.0
2016	1,313,823.08	45,108	45,078	0.0343	1,308,160	29.00	45,109	1.0
2017	268,558.82	0	0	0.0000	276,616	30.00	9,221	0.0
TOTAL	31,562,023.61	17,202,873	17,191,454		15,317,430		1,084,866	

COMPOSITE ANNUAL ACCRUAL RATE	3.44%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.54
COMPOSITE AVERAGE AGE (YEARS)	16.36
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	14.12

FortisBC Energy Inc.

Account #: 46300 - TRANSMISSION PLANT - MEASURING AND REGULATING STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S2
ASL: 38
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1972	30,628.34	28,596	31,953	1.0432	3,270	7.15	457	45.0
1974	12,536.32	11,455	12,800	1.0210	1,617	7.81	207	43.0
1980	1,662.26	1,407	1,572	0.9455	340	10.04	34	37.0
1982	1,246.15	1,023	1,143	0.9169	291	10.89	27	35.0
1984	8,916.23	7,072	7,902	0.8862	2,352	11.79	199	33.0
1985	3,043.26	2,370	2,648	0.8700	852	12.27	69	32.0
1986	1,364.56	1,042	1,164	0.8533	405	12.77	32	31.0
1987	8,403.96	6,287	7,025	0.8359	2,639	13.28	199	30.0
1988	154,445.17	113,056	126,325	0.8179	51,287	13.81	3,713	29.0
1989	1,902.24	1,361	1,520	0.7993	667	14.36	46	28.0
1990	5,248.61	3,664	4,094	0.7799	1,942	14.94	130	27.0
1991	4,020,729.51	2,734,290	3,055,190	0.7599	1,568,649	15.53	101,015	26.0
1992	261,654.07	173,069	193,381	0.7391	107,521	16.14	6,660	25.0
1993	174,055.32	111,771	124,889	0.7175	75,275	16.78	4,486	24.0
1994	71,195.96	44,296	49,495	0.6952	32,381	17.44	1,857	23.0
1995	472,438.09	284,169	317,520	0.6721	225,784	18.12	12,457	22.0
1996	351,481.11	203,888	227,816	0.6482	176,387	18.83	9,366	21.0
1997	221,633.75	123,660	138,172	0.6234	116,706	19.56	5,965	20.0
1998	120,531.61	64,496	72,066	0.5979	66,546	20.32	3,275	19.0
1999	620,189.29	317,222	354,452	0.5715	358,766	21.10	17,004	18.0
2000	399,305.88	194,536	217,367	0.5444	241,835	21.90	11,042	17.0
2001	105,861.23	48,927	54,669	0.5164	67,072	22.73	2,951	16.0
2002	810,460.26	353,740	395,255	0.4877	536,774	23.58	22,766	15.0
2003	203,948.97	83,643	93,460	0.4583	141,082	24.45	5,771	14.0
2004	366,262.99	140,329	156,799	0.4281	264,404	25.34	10,434	13.0
2005	154,564.20	54,960	61,410	0.3973	116,339	26.25	4,432	12.0
2006	1,785,497.10	584,747	653,374	0.3659	1,399,947	27.18	51,510	11.0
2007	1,757,445.92	525,350	587,006	0.3340	1,434,057	28.12	50,993	10.0

FortisBC Energy Inc.

Account #: 46300 - TRANSMISSION PLANT - MEASURING AND REGULATING STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S2
ASL: 38
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2008	109,305.21	29,507	32,970	0.3016	92,731	29.08	3,189	9.0
2009	153,026.94	36,821	41,142	0.2689	134,839	30.05	4,487	8.0
2010	335,640.83	70,816	79,127	0.2358	306,860	31.03	9,890	7.0
2011	150,303.34	27,225	30,421	0.2024	142,428	32.01	4,449	6.0
2012	134,458.66	20,319	22,703	0.1688	131,924	33.01	3,997	5.0
2013	898,378.10	108,683	121,438	0.1352	911,697	34.00	26,813	4.0
2014	126,075.03	11,444	12,787	0.1014	132,200	35.00	3,777	3.0
2015	416,283.29	25,195	28,152	0.0676	450,574	36.00	12,516	2.0
2016	266,712.24	8,072	9,019	0.0338	297,700	37.00	8,046	1.0
2017	359,365.54	0	0	0.0000	413,270	38.00	10,876	0.0
TOTAL	15,076,201.54	6,558,506	7,328,222		10,009,410		415,139	

COMPOSITE ANNUAL ACCRUAL RATE	2.75%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.49
COMPOSITE AVERAGE AGE (YEARS)	15.82
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	23.63

FortisBC Energy Inc.

Account #: 46400 - TRANSMISSION PLANT - OTHER STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1973	7,845.44	8,090	7,193	0.9168	1,045	0.54	1,045	44.0
1975	1,992.26	2,031	1,806	0.9064	286	0.87	286	42.0
1978	6,315.00	6,289	5,591	0.8854	1,039	1.55	671	39.0
1979	10,826.17	10,687	9,502	0.8777	1,866	1.80	1,038	38.0
1983	8,868.78	8,411	7,479	0.8433	1,833	2.90	632	34.0
1984	3,199.30	2,998	2,666	0.8333	693	3.22	215	33.0
1987	18,636.05	16,698	14,846	0.7966	4,722	4.40	1,073	30.0
1988	12,898.76	11,335	10,079	0.7814	3,465	4.89	708	29.0
1989	5,246.07	4,510	4,010	0.7644	1,498	5.44	276	28.0
1990	4,177.22	3,504	3,116	0.7458	1,271	6.03	211	27.0
1991	26,130.83	21,335	18,969	0.7259	8,468	6.67	1,269	26.0
1993	9,555.00	7,345	6,531	0.6835	3,502	8.04	436	24.0
1994	43,742.33	32,527	28,921	0.6612	17,009	8.75	1,943	23.0
1995	565.90	406	361	0.6381	233	9.50	25	22.0
1996	76,883.05	53,113	47,223	0.6142	33,504	10.26	3,265	21.0
1997	17,012.33	11,281	10,030	0.5896	7,833	11.05	709	20.0
1998	3,010.54	1,910	1,698	0.5641	1,463	11.87	123	19.0
1999	191,806.97	116,060	103,190	0.5380	98,207	12.71	7,726	18.0
2000	105,424.54	60,606	53,885	0.5111	56,810	13.58	4,185	17.0
2001	3,833,288.66	2,085,096	1,853,887	0.4836	2,171,066	14.46	150,156	16.0
2002	537,707.52	275,501	244,952	0.4555	319,641	15.36	20,809	15.0
2003	10,828.76	5,200	4,623	0.4269	6,747	16.28	414	14.0
2004	554,794.63	248,254	220,726	0.3979	361,809	17.22	21,017	13.0
2005	288,414.54	119,495	106,245	0.3684	196,590	18.16	10,824	12.0
2006	238,200.38	90,700	80,642	0.3385	169,468	19.12	8,863	11.0
2007	104,381.11	36,211	32,195	0.3084	77,405	20.09	3,853	10.0
2008	163.42	51	45	0.2781	126	21.06	6	9.0
2009	22,991.57	6,402	5,692	0.2476	18,449	22.04	837	8.0

FortisBC Energy Inc.

Account #: 46400 - TRANSMISSION PLANT - OTHER STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 30
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	7,291.71	1,273	1,131	0.1552	6,525	25.01	261	5.0
2013	331,857.79	46,362	41,221	0.1242	307,230	26.01	11,813	4.0
2014	18,679.57	1,958	1,741	0.0932	17,873	27.00	662	3.0
2015	70,917.02	4,958	4,408	0.0622	70,055	28.00	2,502	2.0
2016	194,526.30	6,801	6,047	0.0311	198,206	29.00	6,834	1.0
TOTAL	6,768,179.52	3,307,395	2,940,650		4,165,938		264,685	

COMPOSITE ANNUAL ACCRUAL RATE	3.91%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.43
COMPOSITE AVERAGE AGE (YEARS)	14.44
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.04

FortisBC Energy Inc.

Account #: 46500 - TRANSMISSION PLANT - TRANSMISSION PIPELINE

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 65
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	12,547.23	12,241	11,652	0.9287	3,405	12.16	280	60.0
1958	11,212,155.65	10,814,366	10,294,166	0.9181	3,160,421	12.76	247,777	59.0
1959	1,164,344.86	1,109,693	1,056,314	0.9072	340,900	13.38	25,486	58.0
1960	17,607.69	16,573	15,776	0.8960	5,353	14.01	382	57.0
1961	127,805.46	118,754	113,042	0.8845	40,325	14.67	2,749	56.0
1962	2,415,847.05	2,214,938	2,108,393	0.8727	790,623	15.34	51,547	55.0
1963	92,529.62	83,675	79,650	0.8608	31,386	16.02	1,960	54.0
1964	47,767.60	42,587	40,539	0.8487	16,782	16.71	1,004	53.0
1966	208,320.66	180,301	171,628	0.8239	78,357	18.12	4,325	51.0
1967	422,153.62	359,750	342,445	0.8112	164,140	18.84	8,712	50.0
1968	768,609.24	644,575	613,569	0.7983	308,762	19.57	15,774	49.0
1969	1,589,701.87	1,311,314	1,248,236	0.7852	659,406	20.32	32,453	48.0
1970	362,907.47	294,284	280,129	0.7719	155,360	21.08	7,371	47.0
1971	2,271,303.02	1,809,611	1,722,564	0.7584	1,003,000	21.84	45,917	46.0
1972	7,690,877.42	6,016,807	5,727,382	0.7447	3,501,670	22.62	154,778	45.0
1973	409,455.57	314,346	299,225	0.7308	192,122	23.42	8,205	44.0
1974	32,703.80	24,623	23,438	0.7167	15,806	24.22	653	43.0
1975	61,155.51	45,124	42,953	0.7024	30,433	25.03	1,216	42.0
1976	17,356,855.61	12,542,571	11,939,239	0.6879	8,888,988	25.86	343,767	41.0
1977	272,605.58	192,781	183,508	0.6732	143,619	26.69	5,380	40.0
1978	350,257.34	242,223	230,571	0.6583	189,738	27.54	6,889	39.0
1979	47,298.96	31,961	30,423	0.6432	26,335	28.40	927	38.0
1980	729,273.32	481,112	457,969	0.6280	417,159	29.27	14,254	37.0
1981	1,378,819.03	887,295	844,613	0.6126	809,970	30.14	26,871	36.0
1982	644,241.64	404,045	384,609	0.5970	388,481	31.03	12,520	35.0
1983	315,062.27	192,389	183,134	0.5813	194,940	31.92	6,106	34.0
1984	482,286.28	286,459	272,680	0.5654	306,064	32.83	9,324	33.0
1985	1,077,972.54	622,135	592,208	0.5494	701,359	33.74	20,788	32.0

FortisBC Energy Inc.

Account #: 46500 - TRANSMISSION PLANT - TRANSMISSION PIPELINE

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 65
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1986	3,520,863.50	1,972,270	1,877,398	0.5332	2,347,638	34.66	67,738	31.0
1987	1,812,467.17	984,297	936,950	0.5169	1,238,011	35.58	34,792	30.0
1988	35,341,167.62	18,583,936	17,689,997	0.5005	24,719,404	36.52	676,933	29.0
1989	691,664.91	351,718	334,799	0.4840	495,199	37.46	13,221	28.0
1990	6,652,592.02	3,266,794	3,109,652	0.4674	4,873,458	38.40	126,909	27.0
1991	323,643,863.60	153,249,408	145,877,691	0.4507	242,494,945	39.35	6,162,294	26.0
1992	57,403,074.66	26,167,974	24,909,223	0.4339	43,974,467	40.31	1,090,978	25.0
1993	6,910,030.80	3,027,547	2,881,913	0.4171	5,410,124	41.27	131,099	24.0
1994	2,898,855.51	1,218,464	1,159,852	0.4001	2,318,774	42.23	54,905	23.0
1995	33,221,405.82	13,369,821	12,726,696	0.3831	27,138,991	43.20	628,205	22.0
1996	12,773,412.24	4,911,332	4,675,083	0.3660	10,653,011	44.17	241,165	21.0
1997	8,385,064.52	3,073,030	2,925,209	0.3489	7,136,869	45.15	158,075	20.0
1999	12,476,008.49	4,120,977	3,922,747	0.3144	11,048,463	47.11	234,534	18.0
2000	319,631,845.67	99,774,974	94,975,524	0.2971	288,582,691	48.09	6,000,694	17.0
2001	46,347,661.10	13,624,275	12,968,910	0.2798	42,648,283	49.08	869,003	16.0
2002	25,916,463.36	7,145,876	6,802,140	0.2625	24,297,616	50.06	485,324	15.0
2003	17,982,986.90	4,629,943	4,407,230	0.2451	17,172,355	51.05	336,356	14.0
2004	13,593,419.67	3,251,172	3,094,782	0.2277	13,217,322	52.04	253,960	13.0
2005	11,320,597.83	2,500,212	2,379,944	0.2102	11,204,773	53.04	211,263	12.0
2006	12,529,943.72	2,537,545	2,415,482	0.1928	12,620,450	54.03	233,581	11.0
2007	10,406,022.53	1,916,390	1,824,206	0.1753	10,663,021	55.02	193,787	10.0
2008	11,936,142.82	1,978,888	1,883,698	0.1578	12,439,673	56.02	222,059	9.0
2009	9,207,830.20	1,357,259	1,291,971	0.1403	9,757,425	57.02	171,136	8.0
2010	8,480,401.21	1,094,006	1,041,382	0.1228	9,135,100	58.01	157,468	7.0
2011	57,045,049.41	6,308,887	6,005,412	0.1053	62,448,647	59.01	1,058,282	6.0
2012	15,181,008.20	1,399,335	1,332,023	0.0877	16,885,187	60.01	281,387	5.0
2013	20,775,439.46	1,532,213	1,458,509	0.0702	23,472,018	61.01	384,755	4.0
2014	22,860,081.06	1,264,597	1,203,766	0.0527	26,228,331	62.00	423,013	3.0

FortisBC Energy Inc.

Account #: 46500 - TRANSMISSION PLANT - TRANSMISSION PIPELINE

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 65
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2015	25,031,959.45	923,223	878,814	0.0351	29,159,538	63.00	462,833	2.0
2016	21,074,513.45	388,606	369,913	0.0176	24,919,503	64.00	389,360	1.0
2017	164,895,651.32	0	0	0.0000	197,874,782	65.00	3,044,227	0.0
TOTAL	1,371,509,954.13	427,221,501	406,670,974		1,239,140,971		25,856,752	

COMPOSITE ANNUAL ACCRUAL RATE	1.89%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	17.15
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	48.13

FortisBC Energy Inc.

Account #: 46511 - TRANSMISSION PLANT - INTERMEDIATE PIPE - WHISTLER

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 65
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2008	8,227.20	1,333	1,156	0.1405	8,717	56.22	155	9.0
2009	42,030,839.72	6,061,454	5,256,821	0.1251	45,180,187	57.19	790,024	8.0
2010	133,828.28	16,910	14,665	0.1096	145,929	58.16	2,509	7.0
2014	114,660.54	6,238	5,410	0.0472	132,183	62.05	2,130	3.0
2015	3,584.26	130	113	0.0315	4,188	63.03	66	2.0
2017	4,728.66	0	0	0.0000	5,674	65.00	87	0.0
TOTAL	42,295,868.66	6,086,065	5,278,165		45,476,877		794,972	

COMPOSITE ANNUAL ACCRUAL RATE	1.88%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.12
COMPOSITE AVERAGE AGE (YEARS)	7.98
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	57.21

FortisBC Energy Inc.

Account #: 46600 - TRANSMISSION PLANT - COMPRESSOR EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 37
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1973	1,161,436.28	1,100,281	1,196,279	1.0300	0	2.97	0	44.0
1974	288,030.63	270,593	296,672	1.0300	0	3.25	0	43.0
1975	2,752.84	2,563	2,835	1.0300	0	3.55	0	42.0
1976	12,388.65	11,427	12,677	1.0233	83	3.87	21	41.0
1977	49,027.94	44,757	49,654	1.0128	845	4.21	201	40.0
1978	778,072.63	702,290	779,137	1.0014	22,277	4.58	4,868	39.0
1979	2,841.36	2,533	2,810	0.9889	117	4.98	23	38.0
1981	3,009.83	2,605	2,890	0.9602	210	5.91	36	36.0
1983	31,042.02	25,913	28,748	0.9261	3,225	7.01	460	34.0
1984	3,474.57	2,841	3,152	0.9072	427	7.63	56	33.0
1985	1,287.81	1,030	1,143	0.8872	184	8.27	22	32.0
1986	7,609.26	5,944	6,594	0.8666	1,244	8.94	139	31.0
1987	87,594.98	66,741	74,044	0.8453	16,179	9.63	1,680	30.0
1988	13,505.80	10,024	11,121	0.8234	2,790	10.34	270	29.0
1989	20,082.21	14,499	16,086	0.8010	4,599	11.06	416	28.0
1990	30,473.35	21,368	23,707	0.7779	7,681	11.81	650	27.0
1991	16,391,196.01	11,143,407	12,362,763	0.7542	4,520,169	12.58	359,356	26.0
1992	2,779,861.98	1,828,887	2,029,012	0.7299	834,246	13.37	62,413	25.0
1993	5,084,883.10	3,231,029	3,584,581	0.7049	1,652,848	14.17	116,609	24.0
1994	19,228,123.59	11,774,850	13,063,301	0.6794	6,741,666	15.00	449,384	23.0
1995	4,836,932.85	2,848,011	3,159,652	0.6532	1,822,389	15.85	114,986	22.0
1996	2,007,135.76	1,133,516	1,257,550	0.6265	809,800	16.71	48,453	21.0
1997	3,472,147.04	1,875,703	2,080,950	0.5993	1,495,361	17.59	84,991	20.0
1998	6,109,127.88	3,147,654	3,492,083	0.5716	2,800,318	18.49	151,439	19.0
1999	7,040,821.35	3,449,077	3,826,489	0.5435	3,425,557	19.40	176,550	18.0
2000	50,663,392.07	23,514,921	26,088,017	0.5149	26,095,276	20.33	1,283,774	17.0
2001	5,634,170.57	2,468,197	2,738,277	0.4860	3,064,919	21.26	144,141	16.0
2002	6,487,787.69	2,671,182	2,963,473	0.4568	3,718,948	22.21	167,446	15.0

FortisBC Energy Inc.

Account #: 46600 - TRANSMISSION PLANT - COMPRESSOR EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 37
Net Salvage: -3%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	698,737.94	269,099	298,545	0.4273	421,155	23.17	18,180	14.0
2004	2,337,494.41	837,511	929,154	0.3975	1,478,465	24.13	61,273	13.0
2005	1,867,681.49	618,716	686,418	0.3675	1,237,294	25.10	49,295	12.0
2006	439,909.79	133,775	148,413	0.3374	304,694	26.08	11,685	11.0
2007	18,414,661.89	5,096,873	5,654,593	0.3071	13,312,509	27.06	492,012	10.0
2008	3,315,847.99	826,822	917,297	0.2766	2,498,027	28.04	89,080	9.0
2009	4,689,823.17	1,040,371	1,154,212	0.2461	3,676,306	29.03	126,633	8.0
2011	3,817,924.42	636,029	705,625	0.1848	3,226,837	31.02	104,039	6.0
2012	2,907,689.35	403,851	448,042	0.1541	2,546,879	32.01	79,563	5.0
2013	1,419,948.95	157,834	175,105	0.1233	1,287,442	33.01	39,005	4.0
2014	821,986.80	68,547	76,047	0.0925	770,599	34.00	22,662	3.0
2015	3,514,964.29	195,455	216,843	0.0617	3,403,571	35.00	97,238	2.0
2016	6,666,802.60	185,379	205,664	0.0308	6,661,142	36.00	185,026	1.0
2017	7,368,456.39	0	0	0.0000	7,589,510	37.00	205,122	0.0
TOTAL	190,510,139.53	81,842,106	90,769,657		105,455,787		4,749,197	

COMPOSITE ANNUAL ACCRUAL RATE	2.49%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.48
COMPOSITE AVERAGE AGE (YEARS)	16.01
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	21.57

FortisBC Energy Inc.

Account #: 46700 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT - MT. HAYES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -7%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	5,340,973.30	747,341	1,325,099	0.2481	4,389,742	32.16	136,491	6.0
TOTAL	5,340,973.30	747,341	1,325,099		4,389,742		136,491	

COMPOSITE ANNUAL ACCRUAL RATE	2.56%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	6.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	32.16

FortisBC Energy Inc.

Account #: 46710 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1971	47,395.12	38,701	49,765	1.0500	0	8.23	0	46.0
1972	125,024.32	100,823	131,276	1.0500	0	8.58	0	45.0
1974	16,590.56	13,026	17,420	1.0500	0	9.33	0	43.0
1975	998.36	773	1,048	1.0500	0	9.73	0	42.0
1977	1,038.54	779	1,090	1.0500	0	10.55	0	40.0
1978	3,487.48	2,574	3,608	1.0345	54	10.99	5	39.0
1981	1,834.03	1,282	1,796	0.9794	130	12.37	11	36.0
1982	15,188.66	10,403	14,579	0.9598	1,369	12.87	106	35.0
1984	28,053.01	18,399	25,784	0.9191	3,671	13.89	264	33.0
1985	107,429.56	68,834	96,465	0.8979	16,336	14.42	1,133	32.0
1986	37,810.22	23,640	33,129	0.8762	6,571	14.97	439	31.0
1987	11,619.01	7,080	9,922	0.8539	2,278	15.53	147	30.0
1988	1,116,555.43	662,186	927,999	0.8311	244,384	16.10	15,178	29.0
1989	57,162.09	32,950	46,176	0.8078	13,844	16.69	830	28.0
1991	8,916,170.24	4,833,257	6,773,411	0.7597	2,588,568	17.90	144,627	26.0
1992	1,679,769.34	880,846	1,234,434	0.7349	529,324	18.52	28,579	25.0
1993	1,489,769.95	754,370	1,057,187	0.7096	507,071	19.16	26,470	24.0
1994	974,941.16	475,792	666,784	0.6839	356,904	19.80	18,023	23.0
1995	1,326,452.36	622,587	872,505	0.6578	520,270	20.46	25,428	22.0
1996	971,744.24	437,682	613,376	0.6312	406,956	21.13	19,261	21.0
1997	3,009,742.81	1,297,703	1,818,624	0.6042	1,341,606	21.81	61,523	20.0
1998	1,018,986.95	419,455	587,832	0.5769	482,105	22.49	21,432	19.0
1999	1,849,880.74	724,876	1,015,853	0.5491	926,521	23.19	39,950	18.0
2000	3,975,798.98	1,478,242	2,071,634	0.5211	2,102,955	23.90	87,997	17.0
2001	992,221.07	348,784	488,792	0.4926	553,040	24.61	22,469	16.0
2002	2,339,555.84	774,386	1,085,237	0.4639	1,371,296	25.34	54,124	15.0
2003	4,198,552.53	1,302,636	1,825,537	0.4348	2,582,943	26.07	99,088	14.0
2004	1,071,275.41	309,927	434,337	0.4054	690,502	26.81	25,760	13.0

FortisBC Energy Inc.

Account #: 46710 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 37
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2005	442,888.71	118,761	166,434	0.3758	298,599	27.55	10,838	12.0
2006	2,079,593.79	513,256	719,286	0.3459	1,464,287	28.30	51,736	11.0
2007	1,023,026.17	230,464	322,976	0.3157	751,201	29.06	25,849	10.0
2008	1,433,181.46	291,732	408,838	0.2853	1,096,002	29.83	36,745	9.0
2009	668,341.23	121,407	170,143	0.2546	531,616	30.60	17,374	8.0
2010	557,931.90	89,033	124,772	0.2236	461,057	31.38	14,694	7.0
2011	1,399,067.08	192,107	269,222	0.1924	1,199,799	32.16	37,306	6.0
2012	3,465,259.14	398,038	557,817	0.1610	3,080,705	32.95	93,490	5.0
2013	2,438,253.11	224,914	315,199	0.1293	2,244,967	33.75	66,519	4.0
2014	1,267,718.85	88,035	123,374	0.0973	1,207,731	34.55	34,953	3.0
2015	7,123,268.75	330,960	463,813	0.0651	7,015,619	35.36	198,390	2.0
2016	1,802,909.54	42,020	58,888	0.0327	1,834,167	36.18	50,697	1.0
2017	2,929,838.56	0	0	0.0000	3,076,330	37.00	83,144	0.0
TOTAL	62,016,326.30	18,282,722	25,606,363		39,510,780		1,414,576	

COMPOSITE ANNUAL ACCRUAL RATE	2.28%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.41
COMPOSITE AVERAGE AGE (YEARS)	13.72
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	26.61

FortisBC Energy Inc.

Account #: 46720 - TRANSMISSION PLANT - TELEMETRY EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1972	14,813.00	14,813	14,813	1.0000	0	0.00	0	45.0
1974	2,092.39	2,092	2,092	1.0000	0	0.00	0	43.0
1976	6,935.32	6,935	6,935	1.0000	0	0.00	0	41.0
1978	6,715.46	6,715	6,715	1.0000	0	0.00	0	39.0
1979	1,440.46	1,440	1,440	1.0000	0	0.00	0	38.0
1980	27,834.89	27,835	27,835	1.0000	0	0.00	0	37.0
1981	1,654.26	1,654	1,654	1.0000	0	0.00	0	36.0
1982	8,407.98	8,408	8,408	1.0000	0	0.00	0	35.0
1984	8,673.99	8,674	8,674	1.0000	0	0.00	0	33.0
1985	34,307.63	34,308	34,308	1.0000	0	0.00	0	32.0
1986	526.09	500	526	1.0000	0	0.50	0	31.0
1987	7,999.60	7,542	8,000	1.0000	0	0.57	0	30.0
1988	7,794.38	7,279	7,794	1.0000	0	0.66	0	29.0
1989	960.12	884	948	0.9873	12	0.79	12	28.0
1991	79,689.42	71,178	76,291	0.9574	3,398	1.07	3,181	26.0
1992	92,050.16	80,960	86,776	0.9427	5,274	1.20	4,378	25.0
1993	122,632.08	106,147	113,773	0.9278	8,859	1.34	6,590	24.0
1994	150,236.30	127,839	137,023	0.9120	13,214	1.49	8,864	23.0
1995	289,307.83	241,671	259,032	0.8954	30,275	1.65	18,387	22.0
1996	115,538.74	94,599	101,394	0.8776	14,144	1.81	7,804	21.0
1997	203,844.96	163,310	175,042	0.8587	28,803	1.99	14,485	20.0
1998	92,208.46	72,152	77,335	0.8387	14,873	2.18	6,838	19.0
1999	1,860,197.72	1,418,887	1,520,817	0.8176	339,381	2.37	143,055	18.0
2000	347,116.10	257,534	276,034	0.7952	71,082	2.58	27,543	17.0
2001	461,998.95	332,609	356,503	0.7717	105,496	2.80	37,668	16.0
2002	134,476.79	93,702	100,433	0.7468	34,043	3.03	11,228	15.0
2003	100,351.21	67,493	72,342	0.7209	28,010	3.27	8,554	14.0
2004	439,319.72	284,443	304,877	0.6940	134,443	3.53	38,136	13.0

FortisBC Energy Inc.

Account #: 46720 - TRANSMISSION PLANT - TELEMETRY EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2005	22,377.46	13,913	14,913	0.6664	7,465	3.78	1,974	12.0
2006	1,139,124.34	678,559	727,305	0.6385	411,820	4.04	101,856	11.0
2007	105,467.10	60,037	64,350	0.6101	41,117	4.31	9,545	10.0
2008	176,830.37	95,831	102,715	0.5809	74,115	4.58	16,180	9.0
2009	135,743.49	69,579	74,577	0.5494	61,166	4.87	12,549	8.0
2010	117,666.55	56,399	60,451	0.5137	57,216	5.21	10,989	7.0
2011	3,266,394.36	1,436,795	1,540,011	0.4715	1,726,383	5.60	308,212	6.0
2012	667,450.32	261,481	280,265	0.4199	387,185	6.08	63,657	5.0
2013	1,429,216.71	475,120	509,251	0.3563	919,965	6.68	137,809	4.0
2014	900,248.51	236,073	253,032	0.2811	647,216	7.38	87,726	3.0
2015	3,561,678.00	651,577	698,384	0.1961	2,863,294	8.17	350,439	2.0
2016	765,841.80	72,681	77,903	0.1017	687,939	9.05	76,007	1.0
2017	313,775.31	0	0	0.0000	313,775	10.00	31,378	0.0
TOTAL	17,220,938.33	7,649,652	8,190,973		9,029,965		1,545,043	

COMPOSITE ANNUAL ACCRUAL RATE	8.97%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.48
COMPOSITE AVERAGE AGE (YEARS)	8.28
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.56

FortisBC Energy Inc.

Account #: 46731 - TRANSMISSION PLANT - MEASURING AND REGULATING EQUIPMENT - WHISTLER

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S1.5
ASL: 37
Net Salvage: -7%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2009	313,343.70	70,413	95,978	0.3063	239,300	29.23	8,187	8.0
TOTAL	313,343.70	70,413	95,978		239,300		8,187	

COMPOSITE ANNUAL ACCRUAL RATE	2.61%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	8.00
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.23

FortisBC Energy Inc.

Account #: 46800 - TRANSMISSION PLANT - COMMUNICATIONS EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 19
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1991	1,958,059.29	1,797,935	1,958,059	1.0000	0	1.55	0	26.0
1994	6,552.41	5,742	6,552	1.0000	0	2.35	0	23.0
1995	20,392.63	17,537	20,393	1.0000	0	2.66	0	22.0
1996	3,807.61	3,205	3,808	1.0000	0	3.01	0	21.0
1997	38,261.03	31,409	38,261	1.0000	0	3.40	0	20.0
1998	43,080.18	34,363	43,080	1.0000	0	3.84	0	19.0
1999	3,013.81	2,326	3,014	1.0000	0	4.34	0	18.0
2000	2,407.88	1,789	2,408	1.0000	0	4.88	0	17.0
2001	95,281.20	67,849	95,281	1.0000	0	5.47	0	16.0
2002	47,795.36	32,440	47,795	1.0000	0	6.10	0	15.0
2003	437,413.13	281,349	437,413	1.0000	0	6.78	0	14.0
2004	4,920.95	2,981	4,921	1.0000	0	7.49	0	13.0
2006	14,479.87	7,615	14,480	1.0000	0	9.01	0	11.0
2007	257,488.01	124,535	257,488	1.0000	0	9.81	0	10.0
2008	42,132.78	18,538	42,133	1.0000	0	10.64	0	9.0
2009	229,652.87	90,719	229,653	1.0000	0	11.49	0	8.0
2010	939.84	328	940	1.0000	0	12.37	0	7.0
2011	294,713.93	88,839	294,714	1.0000	0	13.27	0	6.0
2012	12.65	3	13	1.0000	0	14.19	0	5.0
2013	264,839.14	53,961	264,839	1.0000	0	15.13	0	4.0
TOTAL	3,765,244.57	2,663,462	3,765,245		0		0	

** Allocated Booked Amount not equal to summation **

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.27
COMPOSITE AVERAGE AGE (YEARS)	18.45
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.56

FortisBC Energy Inc.

Account #: 47200 - DISTRIBUTION PLANT - STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 38
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1958	20,875.29	20,940	24,007	1.1500	0	4.85	0	59.0
1961	21,710.46	21,230	24,967	1.1500	0	5.69	0	56.0
1962	15,408.41	14,933	17,720	1.1500	0	5.98	0	55.0
1965	559.36	527	643	1.1500	0	6.88	0	52.0
1968	15,488.52	14,134	17,812	1.1500	0	7.85	0	49.0
1969	1,834.27	1,655	2,109	1.1500	0	8.18	0	48.0
1970	15,051.61	13,422	17,309	1.1500	0	8.53	0	47.0
1971	684.49	603	781	1.1405	7	8.89	1	46.0
1972	4,054.62	3,526	4,565	1.1259	98	9.26	11	45.0
1973	13,979.73	11,995	15,530	1.1109	546	9.65	57	44.0
1974	4,055.06	3,431	4,442	1.0954	221	10.04	22	43.0
1975	6,738.60	5,618	7,274	1.0794	476	10.45	46	42.0
1976	1,822.60	1,496	1,937	1.0629	159	10.87	15	41.0
1978	15.33	12	16	1.0283	2	11.76	0	39.0
1979	1,034.00	807	1,045	1.0102	145	12.22	12	38.0
1980	7,195.67	5,510	7,134	0.9915	1,141	12.70	90	37.0
1981	76,431.46	57,397	74,313	0.9723	13,583	13.19	1,030	36.0
1982	8,332.91	6,131	7,937	0.9525	1,645	13.69	120	35.0
1983	41,072.00	29,573	38,290	0.9323	8,943	14.21	629	34.0
1984	26,710.02	18,803	24,345	0.9114	6,372	14.74	432	33.0
1985	11,785.99	8,103	10,491	0.8901	3,063	15.28	200	32.0
1986	114,075.26	76,499	99,046	0.8682	32,141	15.84	2,029	31.0
1987	145,783.14	95,246	123,317	0.8459	44,333	16.41	2,701	30.0
1988	17,436.24	11,084	14,351	0.8230	5,701	17.00	335	29.0
1989	26,851.43	16,585	21,473	0.7997	9,407	17.59	535	28.0
1990	44,063.07	26,405	34,187	0.7759	16,485	18.20	906	27.0
1991	1,005,411.72	583,630	755,641	0.7516	400,583	18.82	21,286	26.0
1992	664,153.92	372,847	482,735	0.7268	281,042	19.45	14,450	25.0

FortisBC Energy Inc.

Account #: 47200 - DISTRIBUTION PLANT - STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 38
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1993	228,802.42	123,998	160,544	0.7017	102,579	20.09	5,105	24.0
1994	756,597.82	395,074	511,513	0.6761	358,575	20.75	17,284	23.0
1995	920,175.98	462,012	598,179	0.6501	460,023	21.41	21,487	22.0
1996	1,005,368.44	484,283	627,013	0.6237	529,160	22.08	23,962	21.0
1997	931,923.87	429,627	556,249	0.5969	515,463	22.77	22,641	20.0
1998	467,849.49	205,877	266,555	0.5697	271,472	23.46	11,572	19.0
1999	446,619.81	187,047	242,174	0.5422	271,438	24.16	11,234	18.0
2000	534,263.30	212,268	274,829	0.5144	339,574	24.87	13,653	17.0
2001	585,007.88	219,710	284,465	0.4863	388,295	25.59	15,174	16.0
2002	222,346.98	78,618	101,789	0.4578	153,910	26.32	5,848	15.0
2003	328,695.14	108,923	141,026	0.4290	236,974	27.05	8,761	14.0
2004	1,222,258.01	377,627	488,924	0.4000	916,673	27.79	32,985	13.0
2005	2,204,487.68	631,211	817,246	0.3707	1,717,915	28.54	60,196	12.0
2006	2,460,551.64	648,380	839,475	0.3412	1,990,160	29.29	67,940	11.0
2007	915,450.31	220,155	285,041	0.3114	767,727	30.05	25,545	10.0
2008	1,056,291.34	229,511	297,154	0.2813	917,581	30.82	29,772	9.0
2009	550,592.54	106,752	138,214	0.2510	494,967	31.59	15,667	8.0
2010	476,707.19	81,180	105,106	0.2205	443,107	32.37	13,688	7.0
2011	2,037,272.74	298,502	386,479	0.1897	1,956,385	33.16	59,001	6.0
2012	996,830.53	122,171	158,178	0.1587	988,177	33.95	29,107	5.0
2013	924,389.54	90,968	117,778	0.1274	945,270	34.75	27,203	4.0
2014	451,612.63	33,455	43,315	0.0959	476,040	35.55	13,390	3.0
2015	1,376,948.94	68,240	88,352	0.0642	1,495,140	36.36	41,118	2.0
2016	881,331.70	21,907	28,364	0.0322	985,168	37.18	26,498	1.0
2017	939,848.46	0	0	0.0000	1,080,826	38.00	28,443	0.0

FortisBC Energy Inc.

Account #: 47200 - DISTRIBUTION PLANT - STRUCTURES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 38
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	25,234,839.56	7,259,637	9,391,375		19,628,690		672,183	

COMPOSITE ANNUAL ACCRUAL RATE	2.66%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.37
COMPOSITE AVERAGE AGE (YEARS)	12.41
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	28.49

FortisBC Energy Inc.

Account #: 47220 - BIO GAS - STRUCTURES AND IMPROVEMENTS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 36
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	136,986.21	23,518	30,139	0.2200	120,546	30.38	3,968	7.0
2013	47,985.30	4,764	6,105	0.1272	46,679	32.75	1,425	4.0
2014	277,415.78	20,735	26,573	0.0958	278,585	33.55	8,303	3.0
2015	159,635.24	7,984	10,232	0.0641	165,367	34.36	4,812	2.0
2016	32,875.21	825	1,057	0.0322	35,106	35.18	998	1.0
TOTAL	654,897.74	57,827	74,106		646,282		19,506	

COMPOSITE ANNUAL ACCRUAL RATE	2.98%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.11
COMPOSITE AVERAGE AGE (YEARS)	3.57
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	33.11

FortisBC Energy Inc.

Account #: 47300 - DISTRIBUTION PLANT - SERVICES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 47
Net Salvage: -70%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1959	1,179,670.70	1,642,479	981,816	0.8323	1,023,624	8.51	120,335	58.0
1960	129,506.03	178,659	106,796	0.8246	113,364	8.86	12,795	57.0
1962	166,632.68	225,435	134,757	0.8087	148,519	9.60	15,476	55.0
1963	232,510.28	311,326	186,100	0.8004	209,168	9.98	20,956	54.0
1964	212,568.64	281,582	168,320	0.7918	193,047	10.38	18,603	53.0
1965	178,772.66	234,178	139,984	0.7830	163,930	10.78	15,201	52.0
1966	223,980.76	289,999	173,351	0.7740	207,416	11.20	18,513	51.0
1967	241,169.74	308,490	184,404	0.7646	225,584	11.64	19,387	50.0
1968	257,382.45	325,095	194,330	0.7550	243,220	12.08	20,135	49.0
1969	197,716.73	246,468	147,330	0.7452	188,788	12.54	15,060	48.0
1970	399,338.72	491,031	293,521	0.7350	385,355	13.00	29,631	47.0
1971	424,486.44	514,553	307,581	0.7246	414,046	13.49	30,700	46.0
1972	527,566.43	630,065	376,631	0.7139	520,232	13.98	37,209	45.0
1973	770,471.57	906,026	541,591	0.7029	768,211	14.49	53,021	44.0
1974	1,004,823.81	1,162,714	695,029	0.6917	1,013,171	15.01	67,506	43.0
1975	961,498.21	1,094,063	653,992	0.6802	980,555	15.54	63,094	42.0
1976	1,385,419.98	1,549,126	926,013	0.6684	1,429,201	16.09	88,847	41.0
1977	1,280,254.50	1,405,729	840,295	0.6564	1,336,137	16.64	80,281	40.0
1978	1,432,039.66	1,542,891	922,286	0.6440	1,512,182	17.21	87,852	39.0
1979	1,392,760.38	1,471,255	879,464	0.6315	1,488,229	17.79	83,633	38.0
1980	1,995,790.62	2,065,403	1,234,625	0.6186	2,158,219	18.39	117,367	37.0
1981	2,959,661.30	2,998,071	1,792,141	0.6055	3,239,283	18.99	170,541	36.0
1982	2,815,123.13	2,788,828	1,667,063	0.5922	3,118,646	19.61	159,024	35.0
1983	3,408,024.36	3,298,733	1,971,866	0.5786	3,821,775	20.24	188,827	34.0
1984	3,133,155.46	2,960,207	1,769,507	0.5648	3,556,857	20.88	170,355	33.0
1985	5,425,368.93	4,998,256	2,987,781	0.5507	6,235,346	21.53	289,619	32.0
1986	2,231,256.86	2,002,232	1,196,864	0.5364	2,596,273	22.19	116,998	31.0
1987	5,283,913.27	4,613,106	2,757,552	0.5219	6,225,100	22.86	272,281	30.0

FortisBC Energy Inc.

Account #: 47300 - DISTRIBUTION PLANT - SERVICES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 47
Net Salvage: -70%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	2,879,416.74	2,442,800	1,460,220	0.5071	3,434,788	23.55	145,881	29.0
1989	4,067,950.10	3,349,228	2,002,051	0.4922	4,913,465	24.24	202,721	28.0
1990	152,108,718.79	121,370,269	72,550,870	0.4770	186,033,952	24.94	7,459,285	27.0
1991	24,726,752.05	19,093,123	11,413,196	0.4616	30,622,282	25.65	1,193,762	26.0
1992	37,852,910.46	28,240,847	16,881,383	0.4460	47,468,564	26.37	1,799,864	25.0
1993	40,486,086.37	29,135,203	17,415,997	0.4302	51,410,349	27.10	1,896,766	24.0
1994	37,579,752.05	26,037,710	15,564,426	0.4142	48,321,153	27.84	1,735,405	23.0
1995	37,216,835.52	24,777,726	14,811,252	0.3980	48,457,369	28.59	1,694,698	22.0
1996	36,296,158.41	23,169,726	13,850,046	0.3816	47,853,424	29.35	1,630,360	21.0
1997	33,799,191.73	20,638,731	12,337,106	0.3650	45,121,520	30.12	1,498,161	20.0
1998	28,892,186.58	16,832,600	10,061,935	0.3483	39,054,782	30.89	1,264,203	19.0
1999	25,058,702.06	13,889,426	8,302,609	0.3313	34,297,184	31.68	1,082,753	18.0
2000	28,365,010.49	14,910,331	8,912,870	0.3142	39,307,648	32.47	1,210,693	17.0
2001	21,738,056.31	10,798,539	6,454,986	0.2969	30,499,710	33.27	916,840	16.0
2002	23,869,561.68	11,160,650	6,671,443	0.2795	33,906,812	34.07	995,119	15.0
2003	24,727,426.30	10,833,133	6,475,665	0.2619	35,560,960	34.89	1,019,296	14.0
2004	28,047,665.36	11,453,768	6,846,659	0.2441	40,834,372	35.71	1,143,505	13.0
2005	34,190,081.97	12,936,567	7,733,024	0.2262	50,390,115	36.54	1,379,073	12.0
2006	35,694,388.24	12,425,916	7,427,775	0.2081	53,252,685	37.38	1,424,801	11.0
2007	43,050,632.76	13,673,587	8,173,588	0.1899	65,012,487	38.22	1,701,059	10.0
2008	45,212,990.02	12,970,162	7,753,106	0.1715	69,108,977	39.07	1,768,898	9.0
2009	32,999,161.16	8,443,830	5,047,424	0.1530	51,051,150	39.93	1,278,655	8.0
2010	34,722,095.00	7,800,354	4,662,777	0.1343	54,364,785	40.79	1,332,828	7.0
2011	36,394,442.11	7,031,148	4,202,973	0.1155	57,667,579	41.66	1,384,284	6.0
2012	42,443,113.48	6,855,120	4,097,749	0.0965	68,055,544	42.53	1,600,003	5.0
2013	43,484,469.55	5,636,352	3,369,213	0.0775	70,554,386	43.42	1,625,061	4.0
2014	45,278,547.58	4,415,196	2,639,249	0.0583	74,334,282	44.30	1,677,820	3.0
2015	43,360,695.42	2,827,211	1,690,007	0.0390	72,023,175	45.20	1,593,526	2.0

FortisBC Energy Inc.

Account #: 47300 - DISTRIBUTION PLANT - SERVICES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 47
Net Salvage: -70%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2016	41,992,521.99	1,372,911	820,678	0.0195	70,566,610	46.10	1,530,859	1.0
2017	54,272,788.87	0	0	0.0000	92,263,741	47.00	1,963,058	0.0
TOTAL	1,160,659,173.45	525,058,164	313,861,268		1,659,259,327		49,532,484	

COMPOSITE ANNUAL ACCRUAL RATE	4.27%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.27
COMPOSITE AVERAGE AGE (YEARS)	14.96
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	34.49

FortisBC Energy Inc.

Account #: 47402 - DISTRIBUTION PLANT - NEW METER INSTALLATIONS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 22
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2012	20,022,156.64	4,550,490	4,961,798	0.2478	15,060,358	17.00	885,903	5.0
2013	27,441,312.43	4,989,330	5,440,303	0.1983	22,001,009	18.00	1,222,278	4.0
2014	20,969,130.22	2,859,427	3,117,884	0.1487	17,851,246	19.00	939,539	3.0
2015	20,316,882.03	1,846,989	2,013,934	0.0991	18,302,948	20.00	915,147	2.0
2016	22,558,412.60	1,025,382	1,118,064	0.0496	21,440,348	21.00	1,020,969	1.0
2017	20,803,385.15	0	0	0.0000	20,803,385	22.00	945,608	0.0
TOTAL	132,111,279.07	15,271,618	16,651,984		115,459,295		5,929,446	

COMPOSITE ANNUAL ACCRUAL RATE	4.49%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.13
COMPOSITE AVERAGE AGE (YEARS)	2.54
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	19.46

FortisBC Energy Inc.

Account #: 47410 - BIO GAS - METER/REGULATOR INSTALLATIONS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S0
ASL: 19
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	21,779.73	7,540	6,259	0.2874	20,966	13.74	1,526	7.0
2014	155,403.41	26,085	21,651	0.1393	172,603	16.45	10,493	3.0
2015	41,398.32	4,822	4,003	0.0967	47,745	17.23	2,771	2.0
2016	7,472.09	456	379	0.0507	8,961	18.07	496	1.0
TOTAL	226,053.55	38,904	32,291		250,276		15,287	

COMPOSITE ANNUAL ACCRUAL RATE	6.76%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.14
COMPOSITE AVERAGE AGE (YEARS)	3.14
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.38

FortisBC Energy Inc.

Account #: 47500 - DISTRIBUTION PLANT - SYSTEMS - MAINS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1959	4,078,881.80	3,602,628	3,968,235	0.9729	1,130,367	19.07	59,270	58.0
1960	93,097.63	81,231	89,474	0.9611	26,898	19.63	1,370	57.0
1961	96,560.73	83,196	91,639	0.9490	29,062	20.20	1,439	56.0
1962	297,138.11	252,692	278,336	0.9367	93,087	20.78	4,480	55.0
1963	641,106.91	537,911	592,500	0.9242	208,883	21.37	9,775	54.0
1964	559,100.97	462,607	509,554	0.9114	189,323	21.97	8,616	53.0
1965	434,372.48	354,275	390,228	0.8984	152,738	22.59	6,762	52.0
1966	890,410.51	715,493	788,103	0.8851	324,910	23.22	13,996	51.0
1967	550,895.17	435,940	480,180	0.8716	208,439	23.85	8,739	50.0
1968	808,709.52	629,895	693,819	0.8579	317,068	24.50	12,943	49.0
1969	1,318,512.93	1,010,340	1,112,873	0.8440	535,268	25.15	21,280	48.0
1970	1,784,193.36	1,344,317	1,480,743	0.8299	749,498	25.82	29,028	47.0
1971	862,120.41	638,376	703,160	0.8156	374,490	26.50	14,134	46.0
1972	1,262,731.56	918,391	1,011,592	0.8011	566,822	27.18	20,854	45.0
1973	1,551,474.30	1,107,697	1,220,109	0.7864	719,233	27.87	25,803	44.0
1974	1,961,796.87	1,374,161	1,513,616	0.7715	938,630	28.58	32,847	43.0
1975	1,278,338.12	877,941	967,037	0.7565	630,885	29.29	21,541	42.0
1976	1,917,243.04	1,290,225	1,421,161	0.7413	975,393	30.01	32,506	41.0
1977	1,801,191.03	1,186,911	1,307,363	0.7258	944,126	30.73	30,719	40.0
1978	1,738,228.02	1,120,855	1,234,603	0.7103	938,182	31.47	29,813	39.0
1979	2,801,785.51	1,766,576	1,945,854	0.6945	1,556,378	32.21	48,315	38.0
1980	3,116,494.24	1,920,014	2,114,864	0.6786	1,780,754	32.96	54,022	37.0
1981	3,541,656.73	2,130,247	2,346,432	0.6625	2,080,639	33.72	61,698	36.0
1982	6,020,425.92	3,532,512	3,891,003	0.6463	3,634,530	34.49	105,383	35.0
1983	9,189,025.13	5,254,986	5,788,279	0.6299	5,698,002	35.26	161,588	34.0
1984	4,446,585.38	2,476,148	2,727,436	0.6134	2,830,795	36.04	78,539	33.0
1985	3,305,030.84	1,790,389	1,972,084	0.5967	2,159,205	36.83	58,625	32.0
1986	2,926,370.19	1,540,536	1,696,875	0.5799	1,961,087	37.63	52,121	31.0

FortisBC Energy Inc.

Account #: 47500 - DISTRIBUTION PLANT - SYSTEMS - MAINS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1987	4,477,678.83	2,288,193	2,520,406	0.5629	3,076,692	38.43	80,066	30.0
1988	2,235,707.17	1,107,737	1,220,154	0.5458	1,574,480	39.24	40,129	29.0
1989	2,789,471.85	1,338,422	1,474,249	0.5285	2,012,590	40.05	50,252	28.0
1990	329,182,041.07	152,744,167	168,245,168	0.5111	243,232,383	40.87	5,951,161	27.0
1991	52,717,599.34	23,622,982	26,020,323	0.4936	39,876,676	41.70	956,308	26.0
1992	78,791,102.47	34,042,461	37,497,207	0.4759	60,991,671	42.53	1,433,988	25.0
1993	43,692,812.30	18,172,416	20,016,615	0.4581	34,599,400	43.37	797,726	24.0
1994	49,256,568.96	19,684,897	21,682,588	0.4402	39,888,124	44.22	902,064	23.0
1995	50,434,166.99	19,329,603	21,291,237	0.4222	41,751,472	45.07	926,364	22.0
1996	43,651,015.88	16,009,981	17,634,728	0.4040	36,929,041	45.93	804,067	21.0
1997	43,446,881.09	15,214,115	16,758,095	0.3857	37,550,506	46.79	802,519	20.0
1998	39,220,581.95	13,079,161	14,406,479	0.3673	34,619,248	47.66	726,392	19.0
1999	40,620,179.42	12,863,360	14,168,777	0.3488	36,606,447	48.53	754,260	18.0
2000	32,164,990.04	9,642,280	10,620,812	0.3302	29,585,426	49.41	598,754	17.0
2001	34,187,859.14	9,667,504	10,648,595	0.3115	32,086,228	50.30	637,952	16.0
2002	27,288,186.71	7,250,199	7,985,974	0.2927	26,124,259	51.18	510,398	15.0
2003	30,847,902.95	7,665,851	8,443,807	0.2737	30,116,071	52.08	578,291	14.0
2004	26,653,733.85	6,163,469	6,788,959	0.2547	26,528,208	52.98	500,765	13.0
2005	28,244,247.65	6,040,959	6,654,016	0.2356	28,651,294	53.88	531,780	12.0
2006	33,169,213.95	6,516,129	7,177,408	0.2164	34,284,110	54.78	625,799	11.0
2007	37,025,309.47	6,625,021	7,297,351	0.1971	38,984,286	55.70	699,954	10.0
2008	39,588,798.43	6,387,360	7,035,571	0.1777	42,450,427	56.61	749,873	9.0
2009	35,943,874.55	5,164,233	5,688,317	0.1583	39,241,526	57.53	682,118	8.0
2010	24,137,014.28	3,039,778	3,348,265	0.1387	26,823,003	58.45	458,896	7.0
2011	24,140,920.60	2,610,418	2,875,332	0.1191	27,300,819	59.38	459,787	6.0
2012	25,654,032.35	2,315,530	2,550,518	0.0994	29,517,023	60.31	489,450	5.0
2013	35,297,174.69	2,552,891	2,811,967	0.0797	41,309,501	61.24	674,561	4.0
2014	37,313,432.93	2,027,140	2,232,861	0.0598	44,408,930	62.17	714,257	3.0

FortisBC Energy Inc.

Account #: 47500 - DISTRIBUTION PLANT - SYSTEMS - MAINS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2015	42,870,048.33	1,555,100	1,712,916	0.0400	51,874,644	63.11	821,923	2.0
2016	32,820,996.45	596,049	656,538	0.0200	40,369,708	64.06	630,229	1.0
2017	40,460,170.32	0	0	0.0000	50,575,213	65.00	778,080	0.0
TOTAL	1,427,597,191.42	453,753,892	499,802,391		1,284,694,098		26,374,369	

COMPOSITE ANNUAL ACCRUAL RATE	1.85%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	18.37
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	48.47

FortisBC Energy Inc.

Account #: 47510 - BIO GAS - MAINS - MUNICIPAL LAND

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 65
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	73,652.86	9,276	7,360	0.0999	84,706	58.45	1,449	7.0
2011	45,881.36	4,961	3,937	0.0858	53,415	59.38	900	6.0
2012	422,265.80	38,114	30,243	0.0716	497,590	60.31	8,251	5.0
2014	844,793.09	45,895	36,417	0.0431	1,019,574	62.17	16,398	3.0
2015	268,244.23	9,730	7,721	0.0288	327,584	63.11	5,190	2.0
2016	977.33	18	14	0.0144	1,208	64.06	19	1.0
TOTAL	1,655,814.67	107,994	85,692		1,984,076		32,207	

COMPOSITE ANNUAL ACCRUAL RATE	1.95%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.05
COMPOSITE AVERAGE AGE (YEARS)	3.61
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	61.61

FortisBC Energy Inc.

Account #: 47600 - DISTRIBUTION PLANT - NGV FUEL EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L0
ASL: 7
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2000	141,394.58	103,947	141,395	1.0000	0	1.85	0	17.0
2011	197,271.37	74,971	197,271	1.0000	0	4.34	0	6.0
2015	274,921.70	46,265	274,922	1.0000	0	5.82	0	2.0
TOTAL	613,587.65	225,183	613,588		0		0	

** Allocated Booked Amount not equal to summation **

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	3.50
COMPOSITE AVERAGE AGE (YEARS)	6.74
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.43

FortisBC Energy Inc.

Account #: 47710 - DISTRIBUTION PLANT - MEASURING AND REGULATING

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 33
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1958	39,802.79	43,644	44,579	1.1200	0	0.69	0	59.0
1963	1,338.85	1,410	1,500	1.1200	0	1.98	0	54.0
1964	214.27	224	240	1.1200	0	2.26	0	53.0
1965	784.71	811	879	1.1200	0	2.55	0	52.0
1966	410.59	420	460	1.1200	0	2.83	0	51.0
1969	1,644.28	1,635	1,842	1.1200	0	3.70	0	48.0
1970	4,174.35	4,109	4,675	1.1200	0	3.99	0	47.0
1971	5,454.34	5,315	6,109	1.1200	0	4.29	0	46.0
1973	86,591.83	82,581	96,983	1.1200	0	4.90	0	44.0
1974	1,236.17	1,166	1,385	1.1200	0	5.22	0	43.0
1975	2,550.61	2,377	2,857	1.1200	0	5.54	0	42.0
1976	26,245.35	24,156	29,395	1.1200	0	5.88	0	41.0
1977	8,111.73	7,369	9,085	1.1200	0	6.23	0	40.0
1978	4,340.83	3,890	4,806	1.1072	56	6.60	8	39.0
1979	18,528.72	16,363	20,219	1.0912	533	6.98	76	38.0
1980	78,936.45	68,650	84,824	1.0746	3,585	7.38	486	37.0
1981	12,156.38	10,402	12,852	1.0573	763	7.79	98	36.0
1982	122,522.61	103,047	127,325	1.0392	9,901	8.22	1,205	35.0
1983	186,293.61	153,846	190,093	1.0204	18,556	8.67	2,141	34.0
1984	122,529.06	99,249	122,633	1.0008	14,600	9.13	1,598	33.0
1985	75,067.14	59,571	73,606	0.9805	10,469	9.62	1,088	32.0
1986	592,189.06	459,844	568,185	0.9595	95,067	10.12	9,393	31.0
1987	476,794.18	361,815	447,060	0.9376	86,949	10.64	8,171	30.0
1988	6,649,585.06	4,924,526	6,084,762	0.9151	1,362,773	11.18	121,900	29.0
1989	331,712.73	239,398	295,801	0.8917	75,718	11.74	6,452	28.0
1990	112,497.94	79,000	97,613	0.8677	28,385	12.31	2,306	27.0
1991	2,890,857.40	1,972,103	2,436,738	0.8429	801,022	12.90	62,095	26.0
1992	2,499,636.76	1,653,682	2,043,296	0.8174	756,297	13.51	55,992	25.0

FortisBC Energy Inc.

Account #: 47710 - DISTRIBUTION PLANT - MEASURING AND REGULATING

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 33
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1993	1,867,915.55	1,196,205	1,478,035	0.7913	614,030	14.13	43,452	24.0
1994	3,060,207.64	1,893,289	2,339,355	0.7644	1,088,077	14.77	73,663	23.0
1995	4,725,420.48	2,818,412	3,482,440	0.7370	1,810,031	15.43	117,333	22.0
1996	3,204,657.97	1,838,444	2,271,588	0.7088	1,317,629	16.10	81,856	21.0
1997	3,417,617.40	1,881,130	2,324,331	0.6801	1,503,400	16.78	89,583	20.0
1998	2,385,040.44	1,256,151	1,552,105	0.6508	1,119,141	17.48	64,018	19.0
1999	2,274,524.46	1,142,870	1,412,134	0.6208	1,135,333	18.20	62,397	18.0
2000	3,120,460.76	1,490,937	1,842,207	0.5904	1,652,709	18.92	87,343	17.0
2001	4,567,340.87	2,067,534	2,554,653	0.5593	2,560,769	19.66	130,238	16.0
2002	3,166,628.54	1,352,563	1,671,232	0.5278	1,875,392	20.41	91,864	15.0
2003	7,381,344.26	2,961,124	3,658,776	0.4957	4,608,329	21.18	217,579	14.0
2004	3,652,798.31	1,369,029	1,691,577	0.4631	2,399,557	21.96	109,284	13.0
2005	4,786,428.15	1,665,769	2,058,230	0.4300	3,302,570	22.75	145,194	12.0
2006	7,859,743.29	2,521,918	3,116,091	0.3965	5,686,821	23.55	241,520	11.0
2007	5,523,083.23	1,620,132	2,001,841	0.3624	4,184,012	24.36	171,779	10.0
2008	3,494,676.48	927,661	1,146,221	0.3280	2,767,816	25.18	109,927	9.0
2009	4,974,323.25	1,179,960	1,457,963	0.2931	4,113,279	26.01	158,138	8.0
2010	3,611,191.02	753,406	930,911	0.2578	3,113,623	26.85	115,951	7.0
2011	4,100,924.90	737,029	910,675	0.2221	3,682,361	27.70	132,915	6.0
2012	5,178,959.41	779,414	963,047	0.1860	4,837,387	28.57	169,342	5.0
2013	7,929,207.76	959,142	1,185,120	0.1495	7,695,593	29.44	261,436	4.0
2014	2,178,084.07	198,499	245,266	0.1126	2,194,188	30.31	72,380	3.0
2015	9,058,229.47	552,746	682,976	0.0754	9,462,241	31.20	303,257	2.0
2016	13,284,388.07	406,976	502,861	0.0379	14,375,654	32.10	447,877	1.0
2017	13,896,287.47	0	0	0.0000	15,563,842	33.00	471,632	0.0

FortisBC Energy Inc.

Account #: 47710 - DISTRIBUTION PLANT - MEASURING AND REGULATING

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 33
Net Salvage: -12%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	143,051,691.05	43,950,943	54,289,435		105,928,459		4,242,968	

COMPOSITE ANNUAL ACCRUAL RATE	2.97%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.38
COMPOSITE AVERAGE AGE (YEARS)	11.09
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	23.95

FortisBC Energy Inc.

Account #: 47720 - DISTRIBUTION PLANT - TELEMETRY

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 20
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1959	202.89	213	213	1.0500	0	0.00	0	58.0
1969	9,476.34	9,950	9,950	1.0500	0	0.00	0	48.0
1971	140.82	148	148	1.0500	0	0.00	0	46.0
1973	1,388.40	1,458	1,458	1.0500	0	0.00	0	44.0
1976	195.90	206	206	1.0500	0	0.00	0	41.0
1979	13,885.50	14,580	14,580	1.0500	0	0.00	0	38.0
1982	17,668.21	18,552	18,552	1.0500	0	0.00	0	35.0
1983	49,062.59	51,516	51,516	1.0500	0	0.00	0	34.0
1984	2,366.11	2,422	2,484	1.0500	0	0.50	0	33.0
1985	34,864.11	35,558	36,607	1.0500	0	0.57	0	32.0
1986	61,707.63	62,331	64,793	1.0500	0	0.76	0	31.0
1987	606.69	606	637	1.0500	0	0.98	0	30.0
1988	49,307.96	48,605	51,773	1.0500	0	1.22	0	29.0
1989	8,939.14	8,695	9,386	1.0500	0	1.47	0	28.0
1990	14,049.49	13,481	14,752	1.0500	0	1.72	0	27.0
1991	42,391.77	40,107	44,511	1.0500	0	1.98	0	26.0
1992	67,459.98	62,878	70,833	1.0500	0	2.25	0	25.0
1993	91,073.16	83,514	95,627	1.0500	0	2.53	0	24.0
1994	204,788.68	184,383	215,028	1.0500	0	2.85	0	23.0
1995	225,237.67	198,605	233,782	1.0379	2,717	3.20	848	22.0
1996	1,298,365.09	1,117,770	1,315,750	1.0134	47,533	3.60	13,197	21.0
1997	485,641.16	406,779	478,828	0.9860	31,095	4.05	7,686	20.0
1998	288,214.54	233,974	275,415	0.9556	27,210	4.54	5,997	19.0
1999	274,364.29	214,965	253,039	0.9223	35,043	5.08	6,903	18.0
2000	251,603.83	189,410	222,958	0.8861	41,226	5.66	7,283	17.0
2001	365,241.44	262,934	309,504	0.8474	73,999	6.29	11,769	16.0
2002	146,030.37	100,020	117,736	0.8062	35,596	6.95	5,119	15.0
2003	349,126.49	226,272	266,349	0.7629	100,234	7.66	13,094	14.0

FortisBC Energy Inc.

Account #: 47720 - DISTRIBUTION PLANT - TELEMETRY

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 20
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2004	102,616.33	62,555	73,634	0.7176	34,113	8.39	4,067	13.0
2005	30,951.25	17,628	20,750	0.6704	11,749	9.15	1,284	12.0
2006	189,560.91	100,090	117,818	0.6215	81,221	9.94	8,169	11.0
2007	47,814.20	23,195	27,304	0.5710	22,901	10.76	2,128	10.0
2008	191,400.25	84,394	99,342	0.5190	101,628	11.60	8,760	9.0
2009	104,514.64	41,338	48,660	0.4656	61,080	12.47	4,900	8.0
2010	443,077.92	154,625	182,012	0.4108	283,219	13.35	21,210	7.0
2011	341,644.36	102,967	121,205	0.3548	237,522	14.26	16,657	6.0
2012	1,089,572.03	275,501	324,298	0.2976	819,753	15.18	53,989	5.0
2013	1,489,125.41	303,017	356,688	0.2395	1,206,894	16.12	74,850	4.0
2014	1,584,960.73	243,142	286,207	0.1806	1,378,002	17.08	80,689	3.0
2015	1,238,360.09	127,210	149,742	0.1209	1,150,537	18.04	63,765	2.0
2016	1,800,811.80	92,840	109,284	0.0607	1,781,569	19.02	93,678	1.0
2017	1,922,727.43	0	0	0.0000	2,018,864	20.00	100,943	0.0
TOTAL	14,930,537.60	5,218,431	6,093,360		9,583,704		606,986	

COMPOSITE ANNUAL ACCRUAL RATE	4.07%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.41
COMPOSITE AVERAGE AGE (YEARS)	8.05
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	13.34

FortisBC Energy Inc.

Account #: 47740 - BIO GAS - MEASURING AND REGULATING

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 30
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	275,549.82	56,259	77,514	0.2813	198,035	23.87	8,295	7.0
2011	4,049.98	713	982	0.2425	3,068	24.72	124	6.0
2012	316.05	47	64	0.2032	252	25.58	10	5.0
2013	578,338.21	68,580	94,491	0.1634	483,848	26.44	18,298	4.0
2014	574,444.01	51,349	70,750	0.1232	503,694	27.32	18,438	3.0
2015	484,624.43	29,019	39,983	0.0825	444,642	28.20	15,765	2.0
2016	128,806.43	3,874	5,338	0.0414	123,469	29.10	4,243	1.0
2017	519,493.78	0	0	0.0000	519,494	30.00	17,316	0.0
TOTAL	2,565,622.71	209,841	289,121		2,276,502		82,490	

COMPOSITE ANNUAL ACCRUAL RATE	3.22%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.11
COMPOSITE AVERAGE AGE (YEARS)	2.76
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	27.55

FortisBC Energy Inc.

Account #: 47810 - DISTRIBUTION PLANT - METERS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 18
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1981	126.00	126	121	0.9596	5	0.00	5	36.0
1983	150.97	151	145	0.9596	6	0.00	6	34.0
1985	60,995.50	60,996	58,531	0.9596	2,464	0.00	2,464	32.0
1986	61,657.50	61,658	59,166	0.9596	2,491	0.00	2,491	31.0
1987	67,834.10	67,834	65,093	0.9596	2,741	0.00	2,741	30.0
1988	11,262,856.33	11,262,856	10,807,793	0.9596	455,064	0.00	455,064	29.0
1989	4,719,588.28	4,719,588	4,528,898	0.9596	190,690	0.00	190,690	28.0
1990	11,632,756.19	11,309,624	10,852,671	0.9329	780,085	0.50	780,085	27.0
1991	1,118,415.76	1,086,655	1,042,750	0.9323	75,666	0.51	75,666	26.0
1992	2,415,934.17	2,329,855	2,235,720	0.9254	180,214	0.64	180,214	25.0
1993	2,926,289.05	2,790,452	2,677,707	0.9151	248,582	0.84	248,582	24.0
1994	3,702,617.17	3,483,112	3,342,380	0.9027	360,237	1.07	337,582	23.0
1995	5,292,450.21	4,904,797	4,706,624	0.8893	585,826	1.32	444,334	22.0
1996	7,466,327.68	6,807,633	6,532,578	0.8749	933,750	1.59	588,005	21.0
1997	6,122,644.66	5,480,840	5,259,392	0.8590	863,252	1.89	457,511	20.0
1998	5,334,894.03	4,672,849	4,484,047	0.8405	850,847	2.23	380,905	19.0
1999	8,369,510.76	7,136,777	6,848,423	0.8183	1,521,088	2.65	573,737	18.0
2000	6,135,478.76	5,059,400	4,854,981	0.7913	1,280,498	3.16	405,612	17.0
2001	4,715,925.16	3,733,334	3,582,492	0.7597	1,133,433	3.75	302,216	16.0
2002	10,791,530.96	8,147,822	7,818,618	0.7245	2,972,913	4.41	674,185	15.0
2003	15,891,620.64	11,379,982	10,920,186	0.6872	4,971,435	5.11	972,844	14.0
2004	12,706,752.81	8,576,188	8,229,676	0.6477	4,477,076	5.85	765,151	13.0
2005	7,428,013.77	4,690,194	4,500,692	0.6059	2,927,322	6.63	441,231	12.0
2006	7,541,341.15	4,416,425	4,237,984	0.5620	3,303,357	7.46	442,887	11.0
2007	8,780,595.05	4,721,391	4,530,628	0.5160	4,249,967	8.32	510,736	10.0
2008	6,970,684.13	3,401,234	3,263,811	0.4682	3,706,874	9.22	402,170	9.0
2009	7,554,216.03	3,297,969	3,164,718	0.4189	4,389,498	10.14	432,818	8.0
2010	8,046,955.69	3,089,725	2,964,888	0.3684	5,082,068	11.09	458,311	7.0

FortisBC Energy Inc.

Account #: 47810 - DISTRIBUTION PLANT - METERS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 18
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	10,214,454.14	3,374,636	3,238,287	0.3170	6,976,167	12.05	578,782	6.0
2012	10,618,231.77	2,931,610	2,813,162	0.2649	7,805,070	13.03	598,992	5.0
2013	11,408,782.71	2,524,928	2,422,911	0.2124	8,985,872	14.02	641,100	4.0
2014	10,033,793.05	1,667,743	1,600,360	0.1595	8,433,433	15.01	561,923	3.0
2015	13,242,662.75	1,468,725	1,409,382	0.1064	11,833,280	16.00	739,412	2.0
2016	15,976,348.91	886,430	850,615	0.0532	15,125,734	17.00	889,682	1.0
2017	17,562,242.83	0	0	0.0000	17,562,243	18.00	975,680	0.0
TOTAL	256,174,678.67	139,543,538	133,905,431		122,269,248		15,513,812	

COMPOSITE ANNUAL ACCRUAL RATE	6.06%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	11.99
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	8.20

FortisBC Energy Inc.

Account #: 47820 - DISTRIBUTION PLANT - INSTRUMENTS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R5
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1983	361,761.94	320,836	315,727	0.8727	46,035	3.96	11,626	34.0
1984	2,933.10	2,557	2,517	0.8581	416	4.48	93	33.0
1985	5,631.05	4,817	4,741	0.8419	890	5.06	176	32.0
1986	23,355.78	19,562	19,251	0.8242	4,105	5.68	722	31.0
1987	96,807.57	79,209	77,948	0.8052	18,860	6.36	2,964	30.0
1988	115,160.76	91,839	90,377	0.7848	24,784	7.09	3,497	29.0
1989	93,986.33	72,889	71,728	0.7632	22,258	7.86	2,833	28.0
1990	165,438.23	124,482	122,499	0.7405	42,939	8.66	4,956	27.0
1991	344,502.95	250,935	246,939	0.7168	97,564	9.51	10,263	26.0
1992	754,659.62	530,929	522,475	0.6923	232,185	10.38	22,376	25.0
1993	835,661.00	566,541	557,520	0.6672	278,141	11.27	24,676	24.0
1994	901,190.00	587,347	577,994	0.6414	323,196	12.19	26,516	23.0
1995	785,627.00	491,001	483,183	0.6150	302,444	13.13	23,042	22.0
1996	655,670.92	391,916	385,675	0.5882	269,996	14.08	19,177	21.0
1997	407,431.51	232,268	228,569	0.5610	178,862	15.05	11,887	20.0
1998	53,827.57	29,181	28,716	0.5335	25,112	16.03	1,567	19.0
1999	354,932.07	182,403	179,499	0.5057	175,433	17.01	10,312	18.0
2000	253,791.63	123,228	121,266	0.4778	132,526	18.01	7,360	17.0
2001	375,867.06	171,802	169,066	0.4498	206,801	19.00	10,883	16.0
2002	356,603.79	152,825	150,392	0.4217	206,212	20.00	10,310	15.0
2003	1,390,662.14	556,268	547,410	0.3936	843,252	21.00	40,155	14.0
2004	1,363,377.05	506,406	498,342	0.3655	865,035	22.00	39,320	13.0
2005	288,290.84	98,845	97,271	0.3374	191,020	23.00	8,305	12.0
2006	508,057.41	159,679	157,136	0.3093	350,921	24.00	14,622	11.0
2007	447,712.81	127,921	125,884	0.2812	321,829	25.00	12,873	10.0
2008	308,436.81	79,315	78,052	0.2531	230,385	26.00	8,861	9.0
2009	53,796.50	12,297	12,101	0.2249	41,696	27.00	1,544	8.0
2010	174,068.52	34,815	34,261	0.1968	139,808	28.00	4,993	7.0

FortisBC Energy Inc.

Account #: 47820 - DISTRIBUTION PLANT - INSTRUMENTS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R5
ASL: 35
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	291,813.18	50,027	49,231	0.1687	242,583	29.00	8,365	6.0
2012	118,228.13	16,891	16,622	0.1406	101,606	30.00	3,387	5.0
2013	55,114.41	6,299	6,199	0.1125	48,916	31.00	1,578	4.0
2014	198,933.39	17,053	16,781	0.0844	182,152	32.00	5,692	3.0
2015	229,700.63	13,127	12,918	0.0562	216,782	33.00	6,569	2.0
2016	583,753.69	16,683	16,417	0.0281	567,336	34.00	16,686	1.0
2017	445,044.83	3	3	0.0000	445,042	35.00	12,716	0.0
TOTAL	13,401,830.22	6,122,195	6,024,709		7,377,121		390,904	

COMPOSITE ANNUAL ACCRUAL RATE	2.92%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.45
COMPOSITE AVERAGE AGE (YEARS)	16.18
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	19.01

FortisBC Energy Inc.

Account #: 47830 - BIO GAS - METERS

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 18
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	7,334.33	2,561	4,043	0.5513	3,291	11.72	281	7.0
2013	2,963.75	607	959	0.3235	2,005	14.31	140	4.0
2015	20,495.49	2,129	3,362	0.1640	17,134	16.13	1,062	2.0
2016	4,483.34	234	370	0.0825	4,113	17.06	241	1.0
TOTAL	35,276.91	5,532	8,734		26,543		1,724	

COMPOSITE ANNUAL ACCRUAL RATE	4.89%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	3.08
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	15.18

FortisBC Energy Inc.

Account #: 48210 - GENERAL PLANT - STRUCTURES (FRAME)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 25
Net Salvage: -4%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	581,326.78	451,479	553,771	0.9526	50,809	6.33	8,026	29.0
1990	321.21	239	293	0.9110	41	7.15	6	27.0
1991	295,355.52	213,997	262,482	0.8887	44,688	7.58	5,893	26.0
1992	84,431.17	59,563	73,058	0.8653	14,750	8.04	1,834	25.0
1993	4,057.00	2,781	3,411	0.8408	808	8.52	95	24.0
1994	927,662.45	616,604	756,308	0.8153	208,461	9.02	23,106	23.0
1995	2,424,883.71	1,559,182	1,912,447	0.7887	609,433	9.54	63,859	22.0
1996	961,272.12	596,418	731,549	0.7610	268,174	10.09	26,590	21.0
1997	106,930.77	63,845	78,310	0.7323	32,898	10.65	3,090	20.0
1998	461,537.95	264,405	324,311	0.7027	155,688	11.23	13,865	19.0
1999	139,534.49	76,452	93,773	0.6720	51,343	11.83	4,340	18.0
2000	212,050.32	110,727	135,815	0.6405	84,717	12.45	6,806	17.0
2001	965,021.89	478,383	586,771	0.6080	416,852	13.08	31,861	16.0
2002	890,493.93	417,267	511,807	0.5747	414,307	13.74	30,162	15.0
2003	229,116.44	100,990	123,871	0.5406	114,410	14.40	7,943	14.0
2004	129,112.11	53,240	65,303	0.5058	68,974	15.09	4,572	13.0
2005	218,272.19	83,675	102,633	0.4702	124,370	15.78	7,879	12.0
2006	165,983.01	58,724	72,030	0.4340	100,593	16.50	6,098	11.0
2007	112,080.82	36,284	44,505	0.3971	72,059	17.22	4,185	10.0
2008	104,998.31	30,785	37,760	0.3596	71,439	17.95	3,979	9.0
2009	1,638,457.64	429,620	526,959	0.3216	1,177,037	18.70	62,954	8.0
2010	1,681,868.36	388,193	476,146	0.2831	1,272,997	19.45	65,444	7.0
2011	2,792,753.56	555,783	681,707	0.2441	2,222,757	20.22	109,950	6.0
2012	943,571.42	157,398	193,059	0.2046	788,255	20.99	37,554	5.0
2013	2,433,835.56	326,665	400,678	0.1646	2,130,511	21.77	97,848	4.0
2014	637,885.58	64,576	79,207	0.1242	584,194	22.57	25,888	3.0
2015	490,591.47	33,293	40,836	0.0832	469,379	23.37	20,086	2.0
2016	2,081,535.99	70,995	87,080	0.0418	2,077,718	24.18	85,927	1.0

FortisBC Energy Inc.

Account #: 48210 - GENERAL PLANT - STRUCTURES (FRAME)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 25
Net Salvage: -4%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	1,548,764.34	0	0	0.0000	1,610,715	25.00	64,429	0.0
TOTAL	23,263,706.11	7,301,562	8,955,879		15,238,375		824,266	

COMPOSITE ANNUAL ACCRUAL RATE	3.54%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.38
COMPOSITE AVERAGE AGE (YEARS)	10.31
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	17.46

FortisBC Energy Inc.

Account #: 48220 - GENERAL PLANT - STRUCTURES (MASONRY)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 60
Net Salvage: -4%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	85,734.03	62,308	83,620	0.9753	5,543	18.07	307	57.0
1967	70,596.50	46,682	62,650	0.8874	10,771	21.85	493	50.0
1970	13,832.70	8,724	11,708	0.8464	2,678	23.61	113	47.0
1974	688.62	405	543	0.7887	173	26.09	7	43.0
1975	181.34	105	140	0.7738	48	26.74	2	42.0
1976	248,769.72	140,630	188,732	0.7587	69,988	27.39	2,556	41.0
1977	8,927.00	4,944	6,636	0.7433	2,648	28.05	94	40.0
1978	20,357.44	11,040	14,817	0.7278	6,355	28.71	221	39.0
1979	305,827.48	162,274	217,779	0.7121	100,281	29.39	3,412	38.0
1980	4,921.37	2,553	3,426	0.6962	1,692	30.07	56	37.0
1981	8,968.67	4,545	6,100	0.6801	3,228	30.76	105	36.0
1982	7,755.47	3,836	5,148	0.6638	2,917	31.46	93	35.0
1983	11,041.06	5,326	7,148	0.6474	4,335	32.17	135	34.0
1984	45,537.81	21,404	28,725	0.6308	18,635	32.88	567	33.0
1985	1,086.55	497	667	0.6140	463	33.61	14	32.0
1986	246.00	109	147	0.5970	109	34.34	3	31.0
1987	3,350.06	1,448	1,943	0.5799	1,541	35.07	44	30.0
1988	507,648.78	212,804	285,594	0.5626	242,361	35.82	6,767	29.0
1989	452,674.55	183,870	246,762	0.5451	224,019	36.57	6,126	28.0
1990	114,839.26	45,139	60,579	0.5275	58,854	37.32	1,577	27.0
1991	27,623.86	10,492	14,080	0.5097	14,648	38.09	385	26.0
1992	3,313,005.15	1,214,035	1,629,296	0.4918	1,816,230	38.86	46,739	25.0
1993	141,792.70	50,049	67,169	0.4737	80,296	39.64	2,026	24.0
1994	3,763,964.63	1,277,419	1,714,360	0.4555	2,200,164	40.42	54,432	23.0
1995	3,914,546.17	1,274,903	1,710,983	0.4371	2,360,145	41.21	57,270	22.0
1996	4,205,619.35	1,311,664	1,760,319	0.4186	2,613,525	42.01	62,217	21.0
1997	446,730.18	133,110	178,640	0.3999	285,959	42.81	6,680	20.0
1998	1,376,344.34	390,810	524,487	0.3811	906,911	43.62	20,792	19.0

FortisBC Energy Inc.

Account #: 48220 - GENERAL PLANT - STRUCTURES (MASONRY)

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 60
Net Salvage: -4%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1999	227,140.28	61,290	82,254	0.3621	153,972	44.43	3,465	18.0
2000	662,344.05	169,299	227,208	0.3430	461,630	45.25	10,201	17.0
2001	1,296,436.18	312,811	419,808	0.3238	928,485	46.08	20,150	16.0
2002	492,648.17	111,768	149,998	0.3045	362,356	46.91	7,724	15.0
2003	1,485,841.92	315,521	423,444	0.2850	1,121,831	47.75	23,494	14.0
2004	998,794.21	197,503	265,059	0.2654	773,687	48.59	15,922	13.0
2005	51,569,336.48	9,439,481	12,668,252	0.2457	40,963,858	49.44	828,561	12.0
2006	1,124,782.67	189,240	253,969	0.2258	915,805	50.29	18,209	11.0
2007	3,234,800.57	496,098	665,788	0.2058	2,698,405	51.15	52,753	10.0
2008	994,757.97	137,671	184,762	0.1857	849,787	52.02	16,337	9.0
2009	1,621,202.30	199,951	268,345	0.1655	1,417,706	52.88	26,808	8.0
2010	1,354,068.57	146,502	196,613	0.1452	1,211,618	53.76	22,538	7.0
2011	8,844,345.59	822,302	1,103,571	0.1248	8,094,549	54.64	148,154	6.0
2012	13,406,218.07	1,041,210	1,397,355	0.1042	12,545,112	55.52	225,960	5.0
2013	1,227,074.37	76,426	102,567	0.0836	1,173,590	56.41	20,806	4.0
2014	47,743.01	2,236	3,000	0.0628	46,652	57.30	814	3.0
2015	1,336,452.62	41,812	56,114	0.0420	1,333,797	58.20	22,919	2.0
2016	2,875,651.84	45,079	60,498	0.0210	2,930,180	59.10	49,584	1.0
2017	2,799,015.87	0	0	0.0000	2,910,977	60.00	48,516	0.0
TOTAL	114,701,265.53	20,387,326	27,360,805		91,928,511		1,836,148	

COMPOSITE ANNUAL ACCRUAL RATE	1.60%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	11.78
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	49.75

FortisBC Energy Inc.

Account #: 48400 - GENERAL PLANT - VEHICLES

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L1
ASL: 7
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2001	6,661.85	4,715	5,663	0.8500	0	1.17	0	16.0
2002	99,113.91	67,951	84,247	0.8500	0	1.35	0	15.0
2003	45,758.07	30,293	38,894	0.8500	0	1.55	0	14.0
2004	26,331.50	16,775	22,382	0.8500	0	1.75	0	13.0
2005	221,343.85	135,155	188,142	0.8500	0	1.97	0	12.0
2006	636,366.99	370,677	540,912	0.8500	0	2.20	0	11.0
2007	202,513.47	111,903	172,136	0.8500	0	2.45	0	10.0
2008	520,449.76	270,971	442,382	0.8500	0	2.71	0	9.0
2009	774,089.73	376,582	657,976	0.8500	0	2.99	0	8.0
2010	1,093,291.36	491,785	929,298	0.8500	0	3.30	0	7.0
2011	952,049.37	390,689	750,941	0.7888	58,301	3.62	16,103	6.0
2012	1,000,270.08	367,874	707,090	0.7069	143,140	3.97	36,044	5.0
2013	1,304,499.65	419,607	806,526	0.6183	302,299	4.35	69,478	4.0
2014	1,958,744.18	525,252	1,009,585	0.5154	655,348	4.79	136,769	3.0
2015	3,030,152.89	600,527	1,154,272	0.3809	1,421,358	5.37	264,789	2.0
2016	3,719,956.55	401,419	771,566	0.2074	2,390,397	6.11	391,142	1.0
2017	4,929,979.07	0	0	0.0000	4,190,482	7.00	598,640	0.0
TOTAL	20,521,572.28	4,582,175	8,282,012		9,161,324		1,512,964	

COMPOSITE ANNUAL ACCRUAL RATE	7.37%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.40
COMPOSITE AVERAGE AGE (YEARS)	3.14
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.16

FortisBC Energy Inc.

Account #: 48510 - GENERAL PLANT - HEAVY WORK EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L0.5
ASL: 13
Net Salvage: 5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1992	6,400.00	4,212	6,080	0.9500	0	3.99	0	25.0
1993	49,650.75	32,036	47,168	0.9500	0	4.17	0	24.0
1995	19,242.50	11,880	18,143	0.9429	138	4.55	30	22.0
1996	20,529.03	12,366	18,885	0.9199	617	4.76	130	21.0
1997	32,729.25	19,200	29,322	0.8959	1,771	4.97	356	20.0
1998	52,786.37	30,096	45,962	0.8707	4,185	5.20	805	19.0
1999	16,249.22	8,985	13,721	0.8444	1,716	5.43	316	18.0
2000	12,982.28	6,944	10,605	0.8169	1,728	5.68	304	17.0
2001	16,506.95	8,519	13,010	0.7882	2,672	5.94	450	16.0
2002	14,077.43	6,989	10,673	0.7582	2,700	6.21	435	15.0
2003	33,354.00	15,876	24,245	0.7269	7,442	6.49	1,147	14.0
2005	33,948.14	14,675	22,411	0.6602	9,839	7.08	1,389	12.0
2006	40,804.49	16,689	25,487	0.6246	13,278	7.40	1,794	11.0
2007	542.75	209	319	0.5875	197	7.74	25	10.0
2008	32,668.31	11,739	17,927	0.5487	13,108	8.08	1,622	9.0
2010	67,021.03	20,445	31,223	0.4659	32,447	8.83	3,676	7.0
2011	82,206.26	22,610	34,529	0.4200	43,567	9.24	4,717	6.0
2012	252,922.43	61,117	93,336	0.3690	146,941	9.69	15,159	5.0
2013	3,103.00	633	967	0.3115	1,981	10.21	194	4.0
2014	45,562.75	7,361	11,241	0.2467	32,044	10.79	2,970	3.0
2015	66,430.41	7,569	11,559	0.1740	51,550	11.44	4,506	2.0
2017	5,906.05	0	0	0.0000	5,611	13.00	432	0.0

FortisBC Energy Inc.

Account #: 48510 - GENERAL PLANT - HEAVY WORK EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L0.5
ASL: 13
Net Salvage: 5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	905,623.40	320,148	486,811		373,531		40,457	

COMPOSITE ANNUAL ACCRUAL RATE	4.47%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.54
COMPOSITE AVERAGE AGE (YEARS)	9.92
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	8.16

FortisBC Energy Inc.

Account #: 48520 - GENERAL PLANT - HEAVY MOBILE EQUIPMENT

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L1.5
ASL: 9
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2001	29,463.87	18,973	25,044	0.8500	0	2.18	0	16.0
2003	38,786.72	23,384	32,969	0.8500	0	2.62	0	14.0
2004	186,443.66	108,237	158,477	0.8500	0	2.85	0	13.0
2005	148,469.18	82,721	126,199	0.8500	0	3.10	0	12.0
2006	66,492.85	35,443	56,519	0.8500	0	3.36	0	11.0
2007	136,392.75	69,354	115,934	0.8500	0	3.62	0	10.0
2008	175,242.84	84,741	148,956	0.8500	0	3.88	0	9.0
2009	471,215.64	215,683	400,533	0.8500	0	4.15	0	8.0
2010	648,963.18	278,743	551,619	0.8500	0	4.45	0	7.0
2011	242,682.55	96,277	206,280	0.8500	0	4.80	0	6.0
2012	221,039.84	78,825	172,406	0.7800	15,478	5.22	2,963	5.0
2013	90,225.29	27,618	60,405	0.6695	16,286	5.76	2,828	4.0
2014	849,487.54	206,939	452,617	0.5328	269,447	6.42	41,966	3.0
2015	360,836.68	61,738	135,033	0.3742	171,678	7.19	23,883	2.0
2016	224,292.11	20,029	43,809	0.1953	146,840	8.05	18,231	1.0
2017	1,494,473.78	0	0	0.0000	1,270,303	9.00	141,145	0.0
TOTAL	5,384,508.48	1,408,704	2,686,800		1,890,032		231,015	

COMPOSITE ANNUAL ACCRUAL RATE	4.29%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.50
COMPOSITE AVERAGE AGE (YEARS)	4.39
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.23

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service" [3]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age" [4]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1 shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age." [5] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[6]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

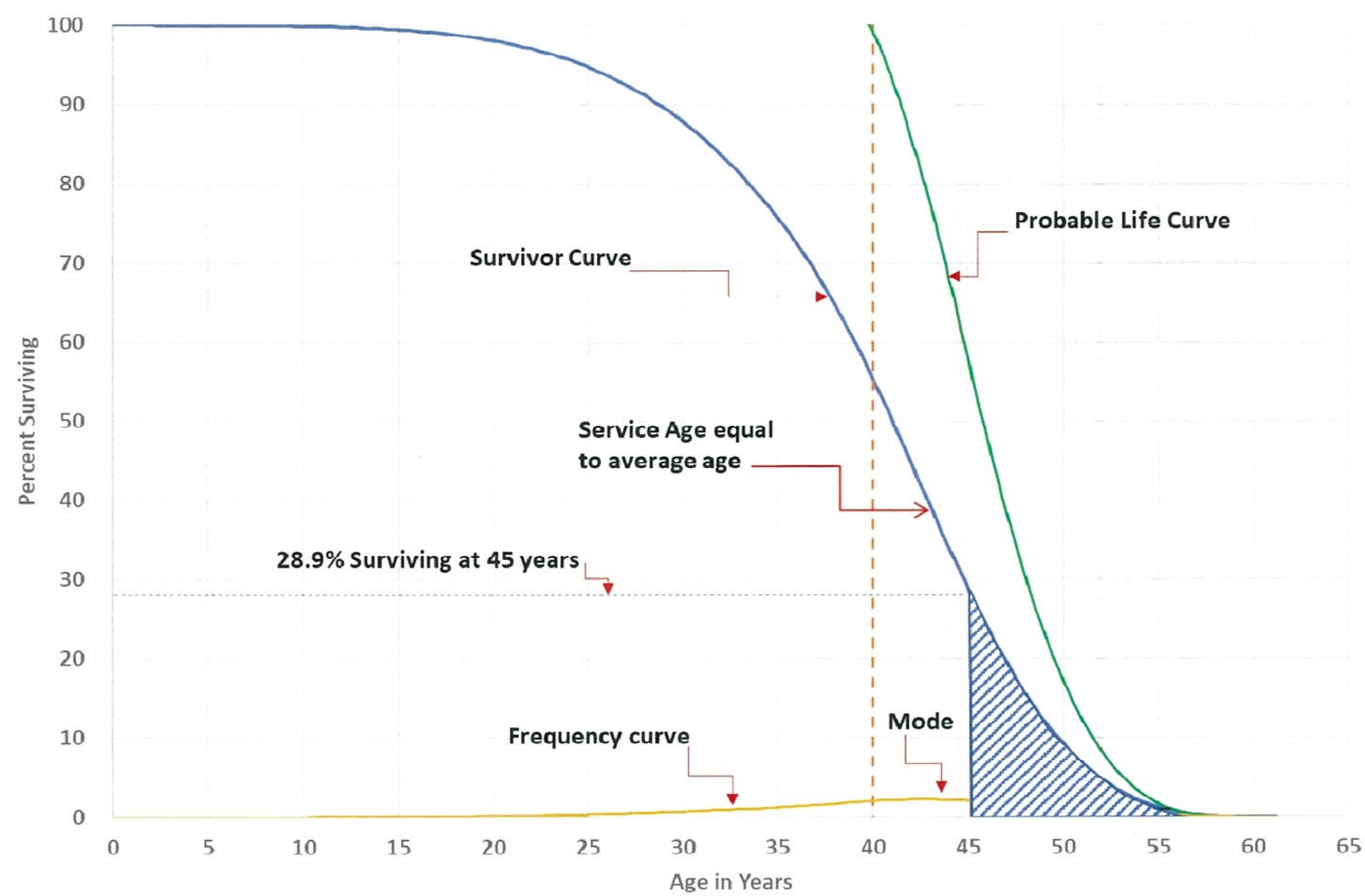
[3] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21.

[4] *Ibid*, 23.

[5] *Ibid*, 29.

[6] *Ibid*, 23-24.

Figure 1: Typical Survivor Curve (40-R4) and Derived Curves



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment" [7]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[8]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[9] presenting his development of the fourth family consisting of the four O-type survivor curves.

[7] *Ibid*, 21

[8] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[9] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

Figure 2: Left Modal or "L" Iowa Type Survivor Curves

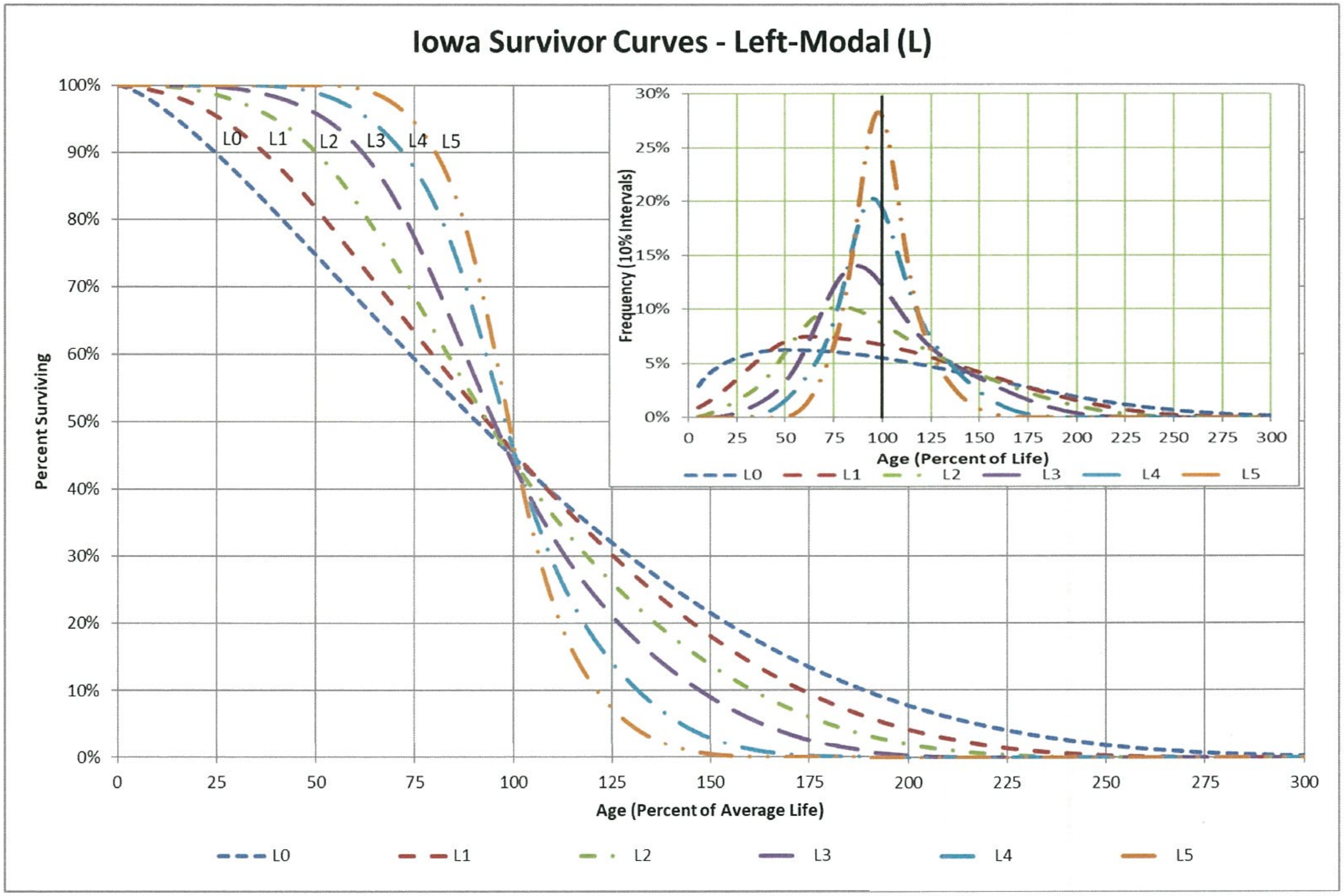


Figure 3: Right Modal or "R" Iowa Type Survivor Curves

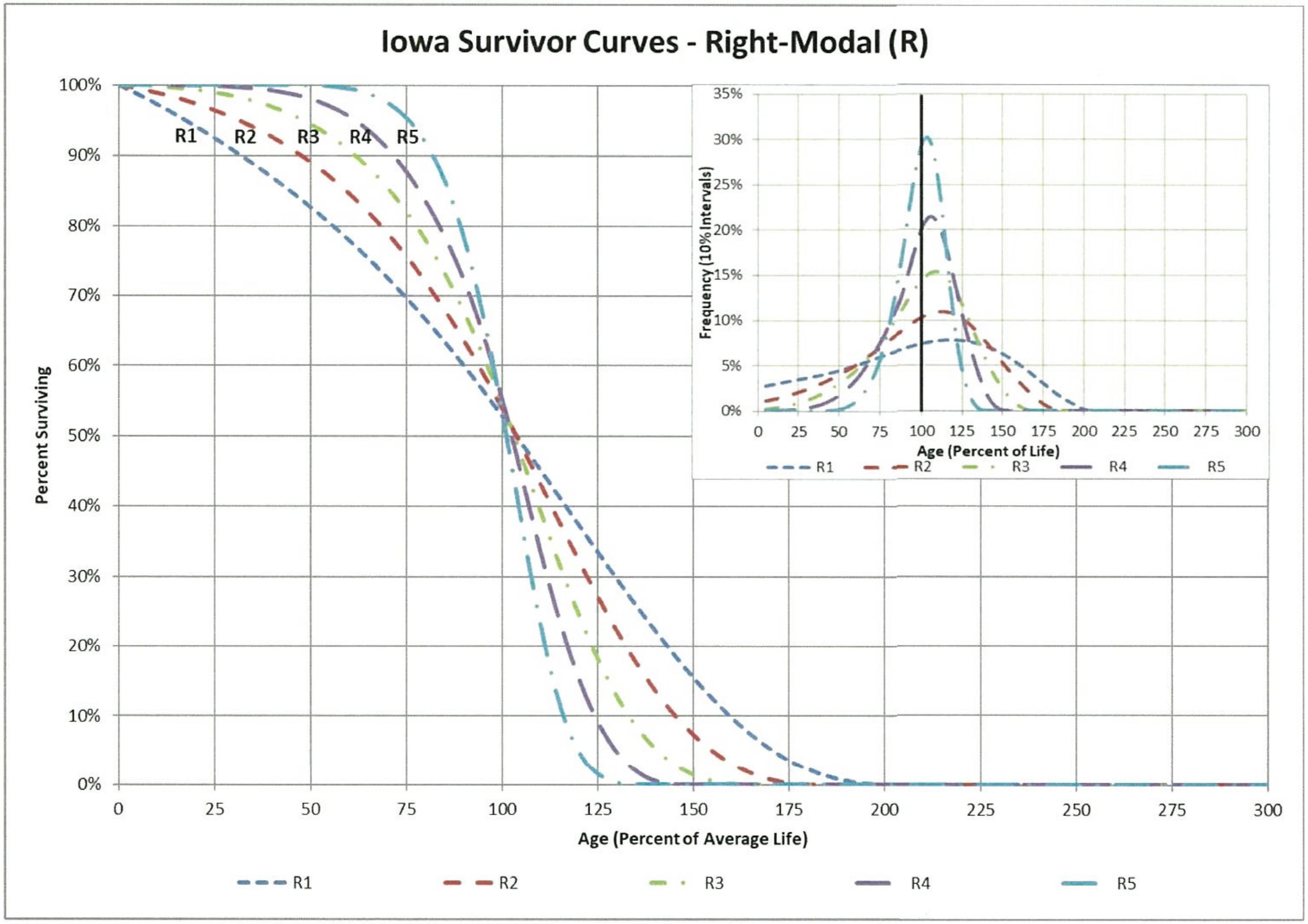


Figure 4: Symmetrical or "S" Iowa Type Survivor Curves

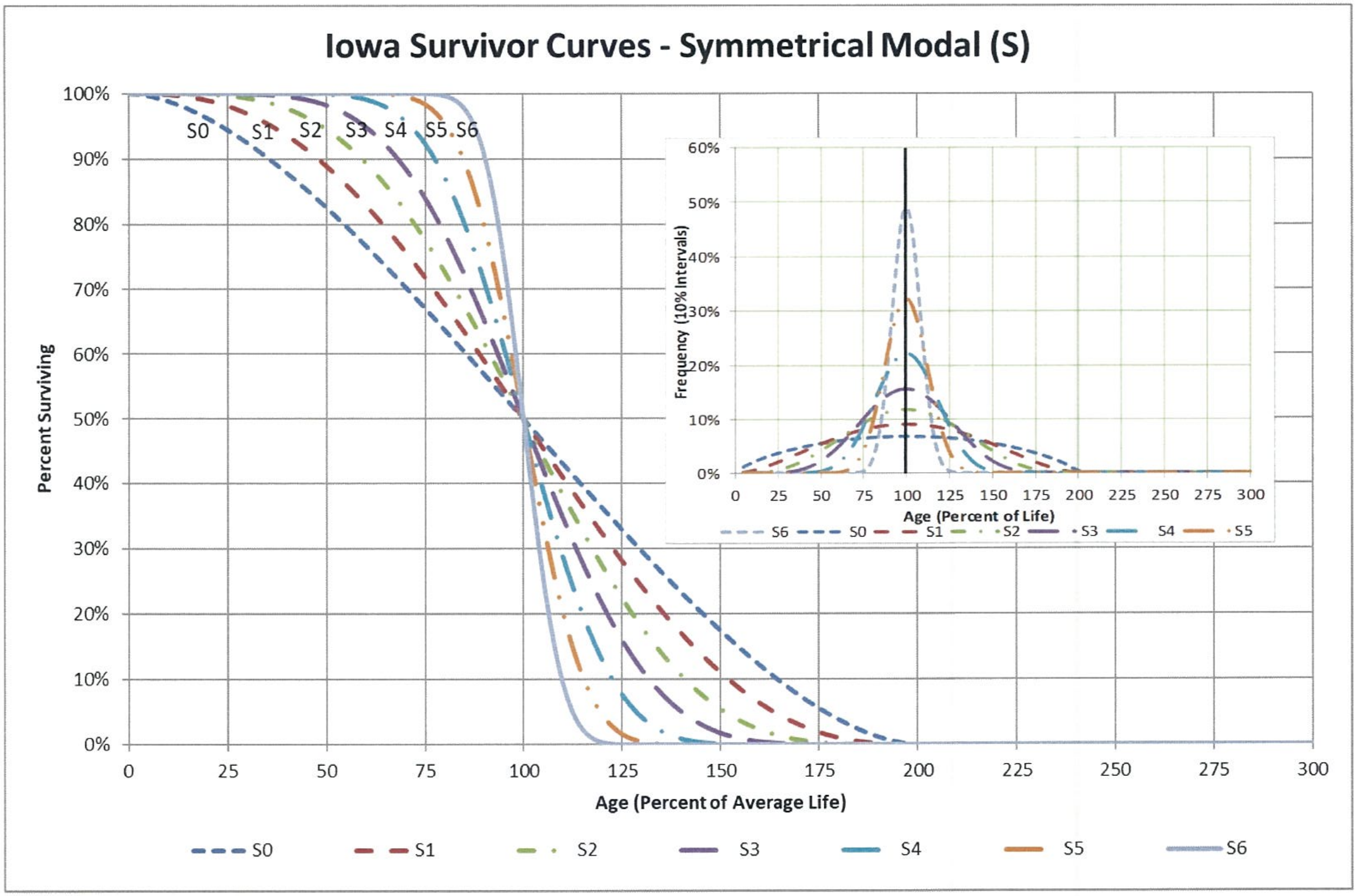
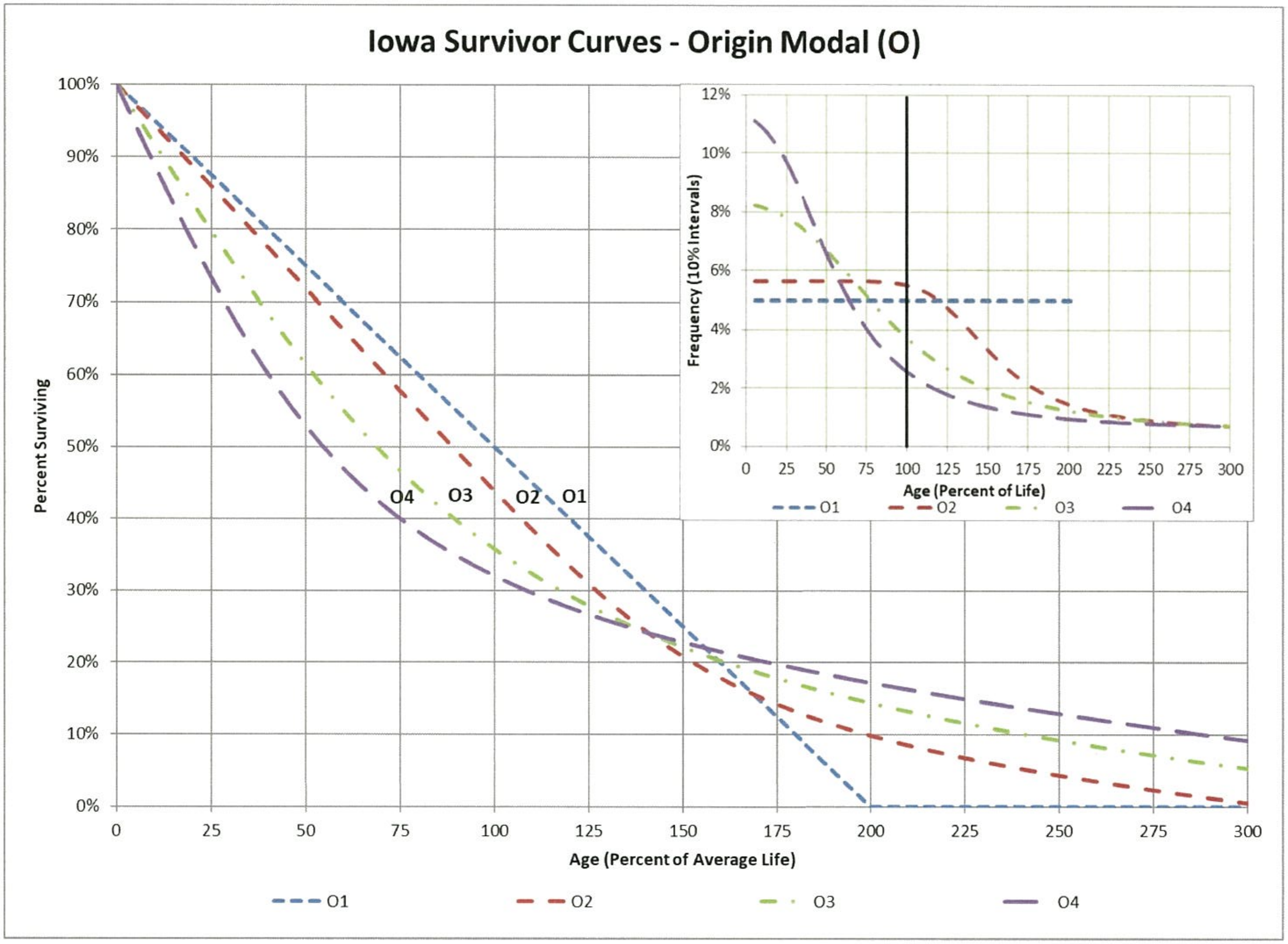


Figure 5: Origin Modal or "O" Iowa Type Survivor Curves



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements,[10] Engineering Valuation and Depreciation[11] and Depreciation Systems.[12]

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-21), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

[10] Marston, Anson, Robley Winfrey and Jean C. Hempstead, *Engineering Valuation and Depreciation* (The Iowa State University Press, 1953)

[11] Anson, Winfrey & Hempstead, supra note 8

[12] Wolf & Fitch, supra note 3

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-22). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

Schedule 1. Retirements for each year 2008-2017 – summarized by age interval

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

Schedule 2. Other Transactions for Each year 2008-2017 – summarized by age interval

Experience Band 2008-2017

Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] *Transfer Affecting Exposures at Beginning of Year*
[b] *Transfer Affecting Exposures at End of Year*
[c] *Sale with Continued Use*
Parentheses denote Credit am ount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-24). The surviving plant at the beginning of each year from 2007 through 2016 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	\$750,000
Exposures at age ½	=	\$750,000 - \$ 8,000	=	\$742,000
Exposures at age 1½	=	\$742,000 - \$18,000	=	\$724,000
Exposures at age 2½	=	\$724,000 - \$20,000 - \$19,000	=	\$685,000
Exposures at age 3½	=	\$685,000 - \$22,000	=	\$663,000

For the entire experience band 2008-2018, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

\$255 + \$268 + \$ 284 + \$311 + \$334 + \$374 + \$405 + \$448 + \$501 \$ \$609 = \$3,789k

Schedule 3 – Plant exposed to retirement at the beginning of each year, 2008 -2017 – summarized by age interval

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

	1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
	420	460	510	580	660	750	850	960	1080	1220	0
	1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 7-25) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	$3,789,000		
Retirements from age 4½ to 5½	=	$143,000		
Retirement Ratio	=	$143,000 ÷ $3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Schedule 4: Original Life Table - Calculated by the Retirement Rate Method

Experience Band 2008-2017				**Placement Band 2003-2017**	
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

Figure 6: Illustration of the Matching of an Original Survivor Curve with a L1 Iowa Type Curve Original and Smooth Survivor Curves

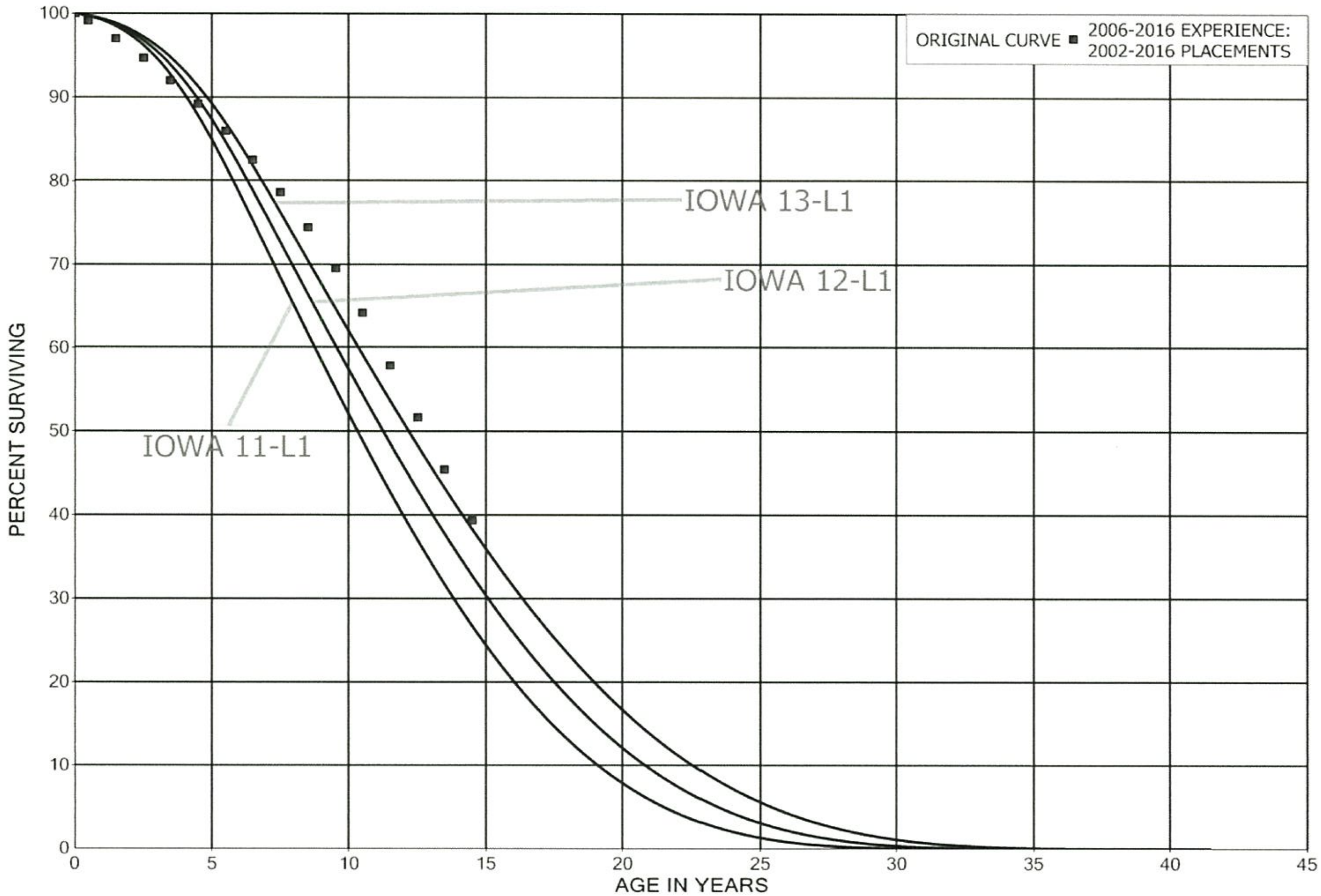


Figure 7: Illustration of the Matching of an Original Survivor Curve with a SO Iowa Type Curve Original and Smooth Survivor Curves

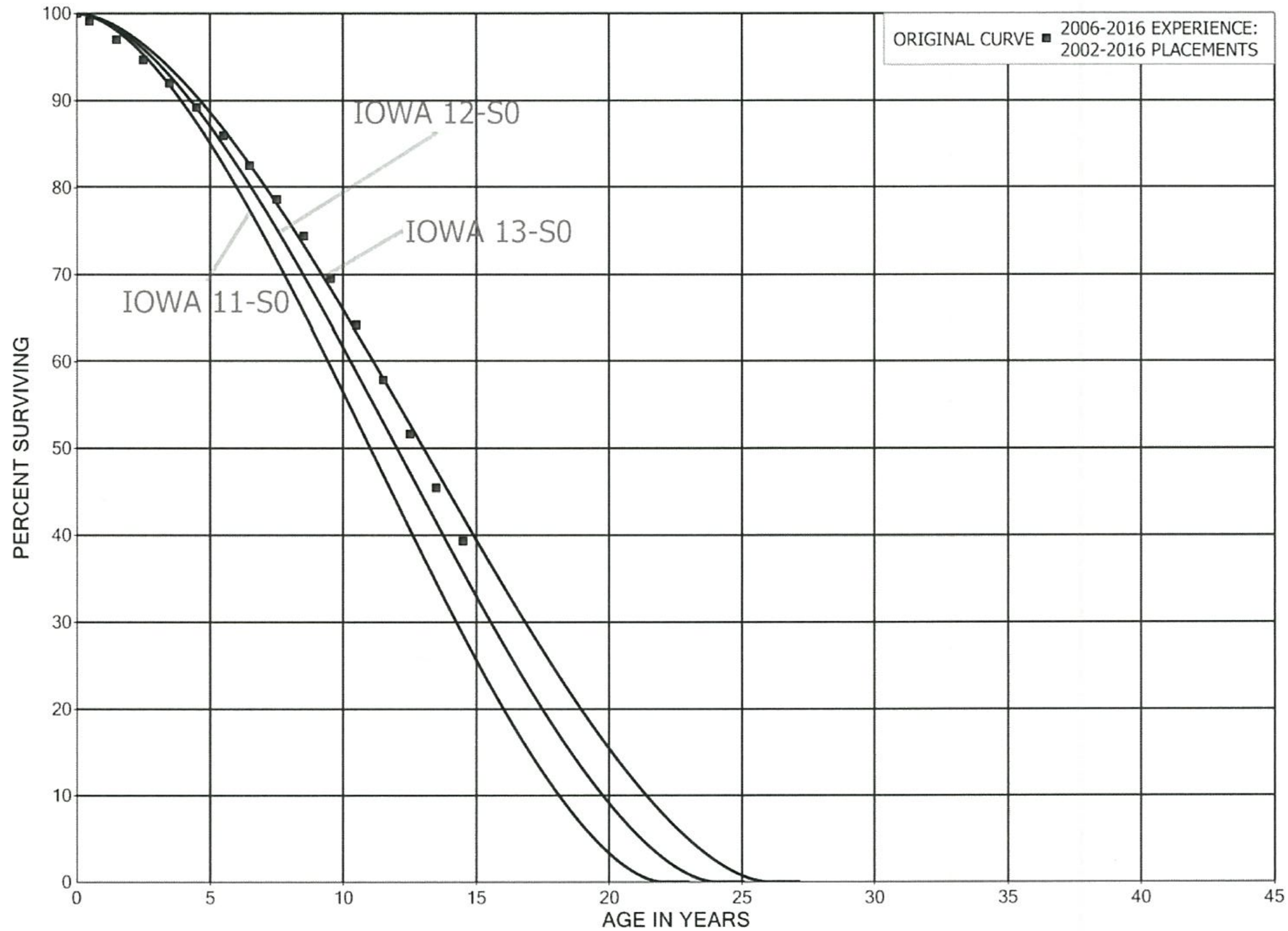


Figure 8: Illustration of the Matching of an Original Survivor Curve with a R1 Iowa Type Curve Original and Smooth Survivor Curves

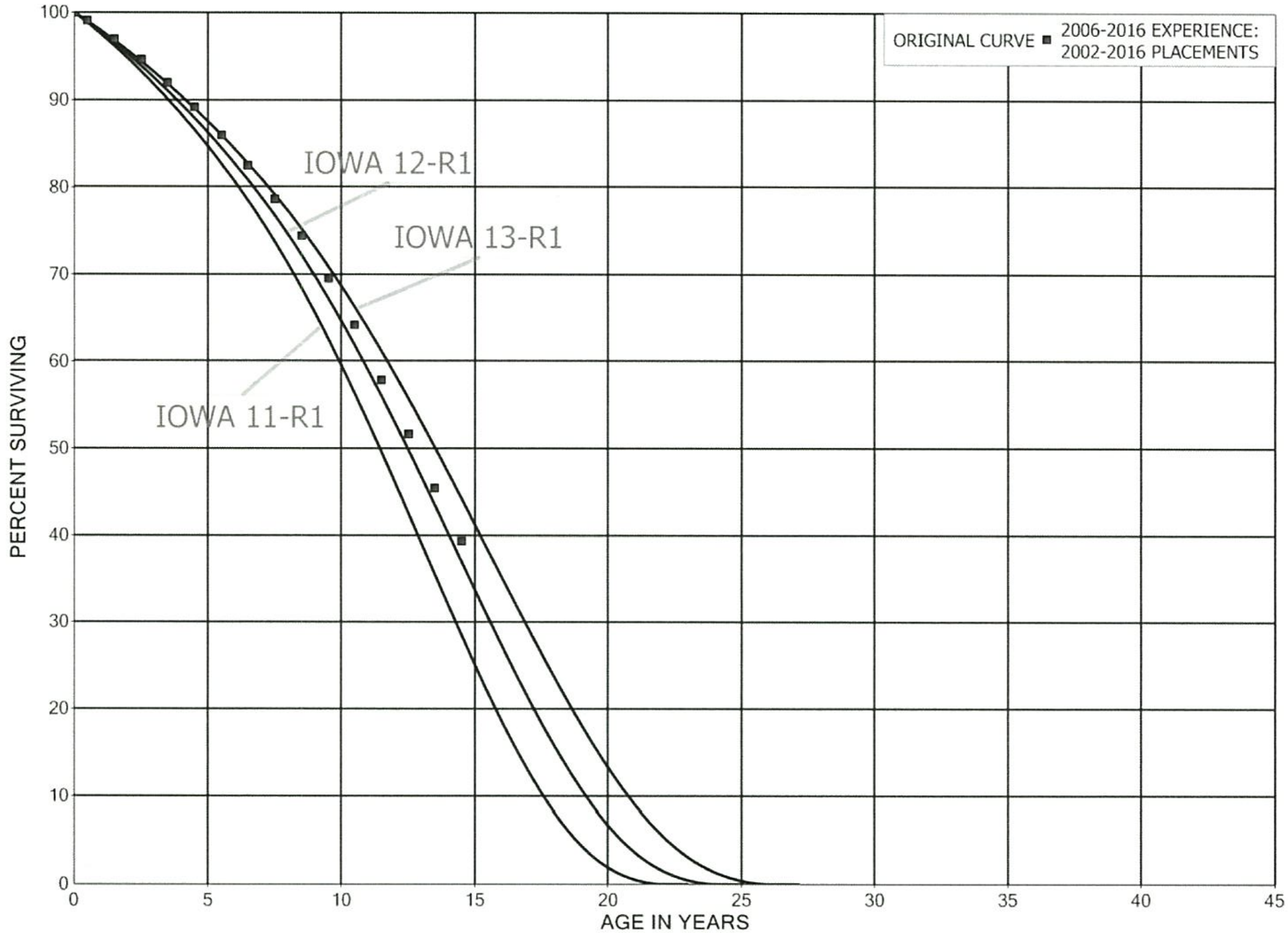
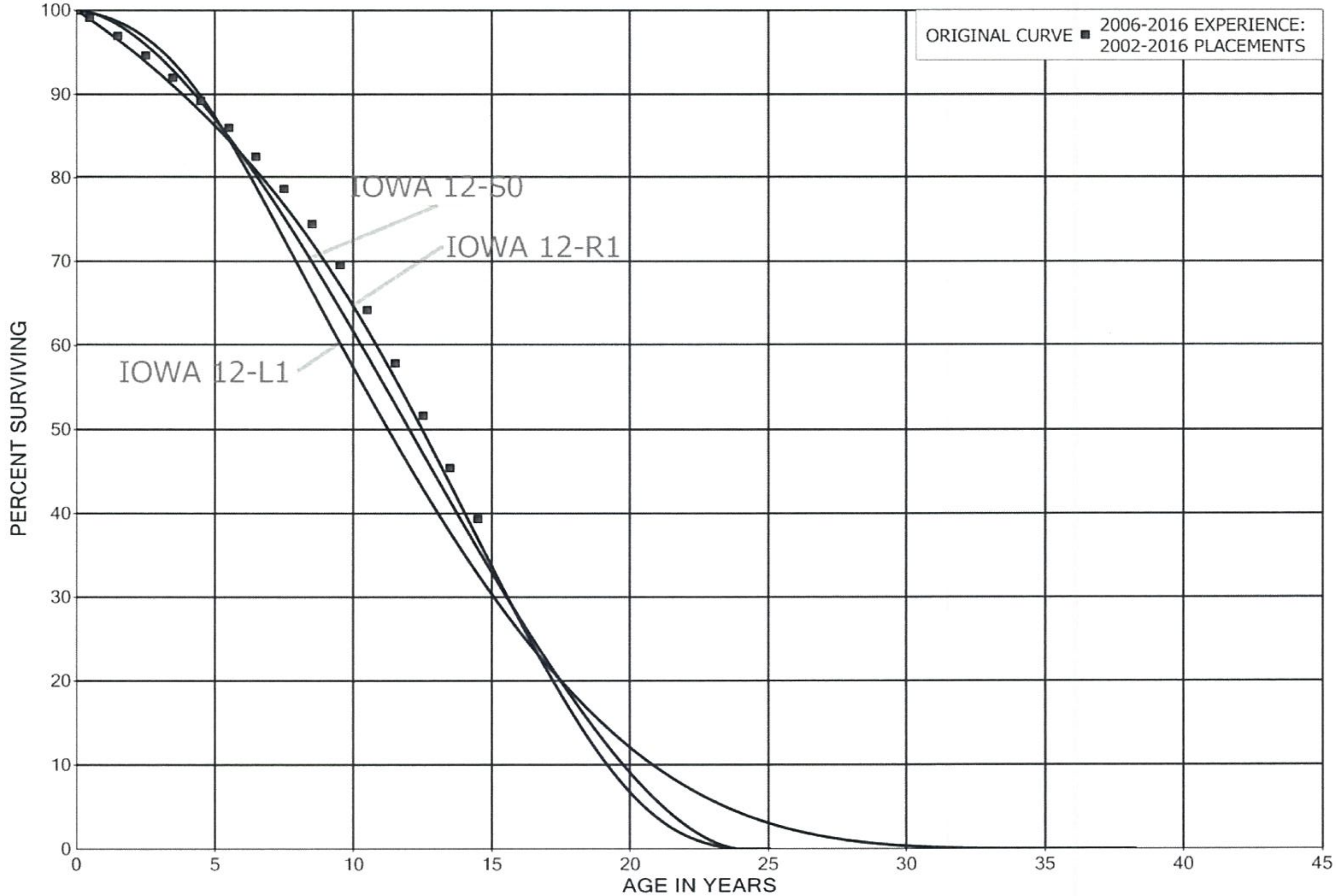


Figure 9: Illustration of the Matching of an Original Survivor Curve with a L1 Iowa Type Curve Original and Smooth Survivor Curves



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated is usually determined using the "Traditional Approach" for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following steps:

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

Appendix D2-2

FBC 2017 DEPRECIATION STUDY

CONCENTRIC ADVISORS

Energy at work FORTIS BC™

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUAL RATES
APPLICABLE TO ELECTRIC GENERATION, TRANSMISSION
AND DISTRIBUTION PLANT IN SERVICE
AS OF DECEMBER 31, 2017

Prepared February 2019

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February 22, 2019

FortisBC - Electricity
Suite 100, 1975 Springfield Road
Kelowna, British Columbia V1Y 7P7

Attention: Lilyana Tabakova
Asset Accounting Manager

Dear Lilyana;

Pursuant to your request, we have conducted a depreciation study related to the electric generation, transmission, distribution, and general plant assets of FortisBC – Electricity, as of December 31, 2017. Our report presents a description of the methods used in the estimation of depreciation and net salvage, the statistical analyses of service life and the summary and detailed tabulations of annual and accrued depreciation.

The calculated annual depreciation accrual rates presented in the report are applicable to plant in service as of December 31, 2017. The depreciation rates are based on the Straight-Line method, the remaining life basis, using the average life group procedure. An annual review of the depreciation rates using the same estimates and methods is recommended.

Yours truly,

CONCENTRIC ADVISORS, ULC

Larry E. Kennedy
Vice President

Project: 70031.00
LEK/bmw

TABLE OF CONTENTS

SECTION 1

1 STUDY HIGHLIGHTS

Pursuant to FortisBC - Electricity's (FortisBC or the "Company") request, Concentric Advisors, ULC ("Concentric") conducted a depreciation study related to the electric generation, transmission, distribution and general plant accounts, as of December 31, 2017. The purpose of this study was to determine the annual depreciation accrual rates and amounts applicable to the original cost of electric plant, as of December 31, 2017.

The depreciation rates are based on the Straight-Line method using the Average Life Group ("ALG") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life and forecasting net salvage characteristics for each depreciable group of assets. Variances between the calculated accrued depreciation and the book accumulated depreciation, as at December 31, 2017, are amortized over the remaining life of assets.

FortisBC's accounting policy has not changed since the last depreciation study was prepared. It continues to recognize the recovery of future costs of removal over the average service of the assets, and therefore includes estimated costs of removal percentages into the depreciation rate calculations costs of removal.

These estimates of salvage values present the continuation of a moderated process to full cost recovery to avoid sharp increases in costs of removal recovery.

Concentric recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric plant in service as of December 31, 2017, as summarized by account detail in Tables 1 and 2 (Section 5, pages 5-2 and 5-3), of this study. Supporting data and calculations are provided as well.

Finally, this study results in an annual depreciation expense accrual related to the recovery of original cost and net salvage requirement of $55.9 million, when applied to depreciable plant balances as of December 31, 2017 of $1.9 billion. The study results are summarized at an aggregate functional group level as follows:

SUMMARY OF ORIGINAL COST, ACCRUAL PERCENTAGES AND AMOUNTS

Plant Group	Original Cost	Annual Accrual	
Generation	$240,182,976	2.09%	$5,024,389
Transmission	$460,766,869	2.40%	$11,063,700
Distribution	$1,004,422,661	2.77%	$27,778,899
General	$187,831,317	6.39%	$12,011,318
TOTAL PLANT IN SERVICE	**$1,893,203,823**	**2.95%**	**$55,878,307**

SECTION 2

2 INTRODUCTION

2.1 Scope

This report sets forth the results of the depreciation study for FortisBC to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of electric plant at December 31, 2017. The rates and amounts are based on the Straight-Line method of depreciation, incorporating the ALG procedure applied on a remaining life basis. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric plant in service as of December 31, 2017.

The service life and net salvage estimates resulting from the study were based on:

- informed professional judgment which incorporated analyses of historical plant retirement data as recorded through December 31, 2017;
- a review of FortisBC practice and outlook as they relate to plant operation and retirement;
- review of FortisBC's recent internal view of the impact of changes in technology and electric generation, transmission and distribution design standards; and
- consideration of current practice in the electric industry, including knowledge of service lives and net salvage estimates used for other electric companies.

2.2 Plan of Study

This study is presented in the following order:

Section 1	Study Highlights, presents a brief summary of the depreciation study and results
Section 2	Introduction, contains statements with respect to the plan and the basis of the study
Section 3	Development of Depreciation Parameters, presents descriptions of the methods used and factors considered in the service life study.
Section 4	Calculation of Annual and Accrued Depreciation presents the methods and procedures used in the calculation of depreciation
Section 5	Results of Study, presents summaries by depreciable group of annual and accrued depreciation in Tables 1and 2
Section 6	Show the results of the Retirement Rate Analysis
Section 7	Presents the Net Salvage Calculations
Section 8	Presents Detailed Depreciation Calculations
Section 9	Estimation of Survivor Curves, is an overview of Iowa curves and the Retirement Rate Analysis
Section 10	Estimation of Net Salvage is an overview of the Net Salvage Analysis

2.3 Depreciation

For most accounts, the annual and accrued depreciation were calculated by the Straight-Line method using the Average Life Group ("ALG") procedure. For certain General Plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages, and estimates of service lives and salvage. Variances between the calculated accrued depreciation or amortization and the book accumulated depreciation are amortized over the composite remaining life of each account.

The Straight-Line method, Average Life Group procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America and has been accepted by the British Columbia Utilities Commission ("BCUC") for FortisBC in previous depreciation studies, including the most recent studies approved by the Commission. Concentric recommends its continued use. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. Many electric utilities in North America, including FortisBC, have received approval to adopt amortization accounting for these accounts.

A full and comprehensive depreciation study includes the following components:

- fully justified recommendations regarding Average Service Life estimates for each account;
- fully justified recommendations regarding estimated Net Salvage requirements for each account;
- detailed calculation of the depreciation rate utilizing the estimated Average Service Life and Net Salvage requirements; and
- a document explaining the procedures followed and justifying the results in a format suitable for submission to senior management and regulatory authorities.

2.4 Service Life and Net salvage Estimates

The service life and salvage estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for electric plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

The resultant depreciation rates are summarized in Tables 1 and 2 (Section 5, pages 5-2 and 5-3) of this study. The depreciation rates should be reviewed periodically to reflect the changes that result from plant and reserve account activity. A depreciation reserve deficiency or surplus will develop if future capital expenditures vary significantly from those anticipated in this study.

2.5 Information Provided by FortisBC

FortisBC has provided Concentric with the required information, as of December 31, 2017, for all accounts being studied. This information has been compiled from the plant accounting records and includes the following:

- current balances by vintage year for each account (aged balances). The balances provide the amount of investment sorted by installation year currently in operation. This file is only inclusive of current plant in service and does not include any retirement information;
- detailed retirement transactions for all accounts. The transactions include information regarding the transaction year of the retirement, the installation year of the asset being retired as well as the original cost of the asset being retired; and
- detailed cost of removal and gross salvage transactions for all accounts requiring the recovery of net salvage. The transactions include information regarding the transaction year of the retirement, the costs associated with the retirement, and any gross salvage proceeds from the sale or reuse of the property.

2.6 Data Reconciliation

The above data was reviewed and reconciled to FortisBC control schedules to ensure accuracy and reasonableness in use of the calculations developed in this study. These checks include:

- that the surviving investment by account equals (or can be reconciled to) the Company's gross plant in service and accumulated depreciation ledger balances;
- that the surviving investment in each vintage is not negative. In other words, this check confirms that the sum of retirements from any given vintage have not exceeded the amount of plant additions to the vintage; and
- that the cost of removal, retirement and gross salvage data over time corresponds to plant and accounting records and their analyses reflects an accurate representation of net salvage.

SECTION 3

3 DEVELOPMENT OF DEPRECIATION RATES

3.1 Depreciation

Depreciation, as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, decay, action of the elements, changes in the art, changes in demand and the requirements of public authorities[1]. When considering the action of the elements, the average service life calculations have considered large catastrophic events that have occurred and impacted the life estimates of utilities across North America. The average service life of utilities has been influenced by events including forest fires, earthquakes, tornadoes, ice storms, wind storms, large scale flooding, fires, actions of third parties and other natural forces of nature.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing electric utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight-Line method of depreciation.

The calculation of annual and accrued depreciation based on the Straight-Line method requires the estimation of survivor curves and is described in the following sections of this report. The development of the proposed depreciation rates also requires the selection of group depreciation procedures, as discussed below.

3.2 Study Depreciation Methods and Procedures

This study calculates the annual and accrued depreciation using the Straight-Line method and Average Life Group procedure for most accounts. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting. Both types of calculations were based on original cost, attained ages and estimates of service lives. Variances between the calculated accrued depreciation and the book accumulated depreciation are amortized over the composite remaining life of each account.

Continued monitoring and maintenance of the accumulated depreciation reserve at the account level is recommended. The depreciation rates determined in this study incorporate any required

[1] The National Association of Railroad and Utilities Commissioners, Uniform System of Accounts for Class A and B Electric Utilities. The Definition used by the Federal Energy Regulatory Commission for electric is essentially the same.

correction between the calculated accrued depreciation (theoretical reserve) and the actual booked accumulated depreciation reserve over the composite remaining life of each account.

3.2.1 Estimation of Survivor Curves and Net Salvage

The use of an Average Service Life Group for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages using the retirement rate method of analysis.

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. The Iowa curves "...were sorted into three groups according to whether the mode was to the left, approximately coincident with, or to the right of the average-life ordinate. The curves in each of these three groups were then sub-classified in accordance with the height of the mode, taking also into consideration the distance of the mode to the left or right of the average life." [2] The Iowa curves are described as L-type (i.e. left-moded), R-type (i.e. right-moded), and S-type (i.e. symmetrical). Further development resulted in the introduction of O-type (i.e. origin-moded curves) where the greatest frequency of retirement occurs at the origin, or immediately after age zero. Individual type curves are further depicted with numerical subscripts which represent the relative heights of the modes of the frequency curves within each family.

The program that is used by Concentric for statistical smooth curve fitting utilizes an internal "goodness-of-fit" criterion which is the residual measure. This residual measure is calculated as a least squares solution of the differences between the stub curve (or original data points) and smooth survivor curve which also requires a balancing of the differences above and below the stub curve.

The criterion of goodness-of-fit is the mean square of the differences between the points on the stub and fitted smooth survivor curves. The residual measure, or standard error of estimate, shown in the output format is the square root of this mean square. As such, the lower the residual measure, the better the statistical fit between the analyzed Iowa curve and the observed data points. Concentric follows the widely-used practice of fitting Iowa curves up to one percent of the maximum exposures. This standard practice is utilized to minimize the influence of typically small retirements applied to similarly small exposures which may unduly affect the Iowa curve fitting process. However, Concentric will recognize the observed data points beyond the one percent of maximum exposures if it is determined that the additional data is a valid consideration for life. A discussion of the general concept of survivor curves and retirement rate method, and net salvage are presented in Sections 9 and 10 of this report.

3.2.2 Survivor Curve and Net Salvage Judgments

The survivor curve estimates were based on judgment which considered a number of factors. The primary factors were the statistical analysis of data; current policies and outlook as determined

[2] Robley Winfrey, Statistical Analyses of Industrial Property Retirements, Bulletin 125 revised (Engineering Research Institute, Iowa State University, 1935) 65

during conversations with management personnel and on the knowledge Concentric developed through the completion of numerous electric utility studies.

The estimates of net salvage were based in part on historical data related to actual retirement activity for the years 1995 through 2017 for most accounts. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account. Percentages of the cost of plant retired were calculated for each component of net salvage on annual, three-year and five-year moving average bases.

FortisBC had included net salvage percentages in the depreciation rate calculations for the first time in the 2015 study (for costs as of December 31, 2014). Prior to this study, the depreciation rates have not included costs of removal estimates. However, actual costs of removal (or retirement) had historically been charged to the accumulated depreciation account, resulting in a burden of recovery of costs by the future toll-payers for costs related to assets that were consumed by past toll-payers. Concentric recommends that FortisBC continue the practice as approved in the last depreciation study to include a provision for the estimated costs of retirement in the depreciation rates. Including a provision for the costs to retire, will provide the total cost responsibility of the assets to the current toll-payer who has access to the assets in service.

Given that there has been only one previous provision for net salvage in the 2014 study, the complete integration of net salvage into the rates would cause a significant impact on the rates charged to customers. Therefore, Concentric is recommending the continuation of the gradual transition to the required amounts of negative salvage percentages.

The following discussion, dealing with a number of accounts which comprise the majority of the investment analyzed, presents an overview of the factors considered by Concentric in the determination of the average service life and net salvage estimates. The survivor curve estimates for the remainder of the accounts not discussed in the following sections were based on similar considerations.

ACCOUNT 331.00 – GENERATION PLANT – STRUCTURES AND IMPROVEMENTS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$18,215,444	0.96%	68-S2.5	60-S1.5	-5%	-10%

This account reflects the cost of buildings or structures associated with the generation of electricity. It includes the fencing, grading, landscaping, sewage, security, water and other services to such buildings, as well as upgrading or improvements over time. Because of the relatively fixed components, this account has not experienced a substantial amount of retirement but recent upgrades and retirements reinforce a shorter life in line with peers in the same industry.

The retirements, additions and other plant transactions, for the period 1978 through 2017, were analyzed by the retirement rate method. The original survivor curve, as plotted on page 6-5, indicates retirement ratios that begin to increase at age four but continue with very variable or low retirement ratios thereafter. Discussions with operational and management staff indicated that the historic retirement patterns for this account will be typical of the expectation going forward. As depicted on page 6-5 in Section 6, an Iowa 60-S1.5 has a better fitting residual measure ("RM") of 1.0314 versus the currently approved curve, Iowa 68-S2.5 with a RM of 1.2545. The 60-S1.5 considers interim retirements that have historically occurred at ages 25 to 35, thus shortening the estimate of average life.

Net salvage percentages are increased to negative 10 percent, in line with much higher costs due to asbestos removal and risk of contamination. The volatility in the salvage data shown on page 7-2, as well as the apparent gaps between retirements and cost of removal in calendar years, represents the lag between the time assets are taken out of service and retired and when they are ultimately removed in the field. Large negative net salvage indicated by historic values more negative than 150 percent for 2017 as well as more negative than 320 percent for the historical average point to more negative net salvage percentages since 2011. Concentric is recommending a gradual increase change from the previously approved negative five percent to negative 10 percent.

ACCOUNT 332.00 – GENERATION PLANT – RESERVOIRS, DAMS AND WATERWAYS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$33,991,864	1.80%	70-S2.5	70-S2	-15%	-25%

The assets in this account include the facilities and structures used in diverting and impounding waterways, as well as the necessary storage and regulation of water needed in the generation of power. The facilities include dams, spillways, foundations, tunnels, gates, bridges and culverts as well as associated control and monitoring systems.

Minor retirements related to on-going capital maintenance have occurred historically. However, it is expected that some wing dams need replacement in the future. The historic retirements to date are interim in nature. The retirement rate analysis looked at transactions between 1977 and 2017, and the retirement ratios shown on page 6-6 are very low and sporadic. Currently, the best fit continues to be 70 years, however Concentric recommends changing the mode to S2 as it is a better statistical fit. The residual measure is 1.3530 for the 70-S2.5 compared to 1.3030 for the 70-S2curve. The 70-S2 estimate continues to be within the range of peers for reservoirs, dams and waterways in the generation industry.

The large costs of removals since 2009 as well as the historical average of almost negative 100 percent (page 7-3) would justify increasing the previously approved net salvage from negative 15 percent to negative 25 percent. This gradual increase is in line with a moderate transition of net salvage to reflect true costs of removal.

ACCOUNT 333.00 – GENERATION PLANT – WATER WHEELS, TURBINES AND GENERATORS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$97,569,107	5.15%	70-R2.5	70-R2.5	-20%	-25%

The assets in this account include the necessary hydraulic components, pumps, motors and generators used to generate electricity. This would encompass exciter sets, water wheels, gates, governors, penstocks, oil pumps and their associated foundation works as well as regulators, cooling and monitoring equipment.

As indicated in the original survivor curve plotted on page 6-11, this account has witnessed approximately $1.6 million of retirement activity from 1976 to 2017. Retirements since the last study are in the order of $150,000 and not sufficiently material to move away from the previous recommendation of an Iowa 70-R2.5 survivor curve. A review of the limited data available for peers in this industry with similar components indicated that an Iowa 70-R2.5 curve remained within the reasonable range of life estimate given the foreseeable changeout of these assets. As a result, Concentric recommends maintaining the 70-R2.5 estimate as reflected on page 6-11.

Costs of removal for this account has been sporadic, but high as a function of original costs as shown on page 7-4. Historical net salvage percentages have trended well above the last study's recommendation. Results are sporadic but in instances where there are costs of removal and significant retirements, net salvages have averaged more negative than 150 percent, with historical numbers averaging more negative than 95 percent. In 2017, costs of removal were more negative than 100 percent of the original cost that is retired. It is recommended that a gradual and orderly increase in negative net salvage is continued from the amounts first introduced in the last study. In order to maintain a moderate change in salvage percentages, the recommended net salvage percentage is changed to negative 25 percent to recognize higher costs of removal that are anticipated.

ACCOUNT 334.00 – GENERATION PLANT – ACCESORY ELECTRICAL EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$43,137,705	2.28%	50-R1.5	40-R2.5	-20%	-20%

This account includes the auxiliary, control, switching and conversion equipment associated with generation equipment or motors.

The retirements, additions and other plant transactions for the period 1975 through 2017 were analyzed by the retirement rate method. The original survivor curve as plotted on page 6-14 indicates very low retirements starting early in the accounts life and continuing at a relatively uneven rate throughout the successive age intervals. The retirement rate analysis has indicated that the existing Iowa 50-R1.5 curve provides a good fit related to historical retirements (page 6-14), however it is anticipated that future retirements will most likely not follow the same trends as the past. Discussions with engineering and operations staff provided the expectation that newer digital equipment would not achieve the service lives as witnessed in the past. Operations personnel indicated that the control equipment included in this account has been mostly replaced with digital technology. Newer digital equipment provides for better condition assessments of the assets being protected, however, the technological nature and reliance on vendor support for the technology included in these assets will cause retirement at an earlier age than previously experienced with the older generation mechanical protection equipment. Concentric considers 40-R2.5 curve as more representative of the rate of consumption of service value of these assets. Therefore, Concentric has provided less weighting to the RM given that the assets associated with the retirement ratios which generated the observed RM have largely been retired. Concentric recommends a change to a 40-year life which is consistent with the views of the FortisBC operations and engineering groups, and is within the range of similar accessory electrical equipment in the same peer group.

Recent salvage data shows volatile salvage and cost of removal statistics which, although higher than the last study's recommendations, has indicated a decreasing trend from a three-year average perspective. Discussions with operations indicated that accessory electrical equipment would not normally incur a large cost of removal in the near future. Given the volatility of the recent indications, Concentric recommends maintaining net salvage at negative 20 percent in this study.

ACCOUNT 335.00 – GENERATION PLANT – OTHER POWER PLANT EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$45,020,063	2.38%	51-R4	51-R4	-10%	-15%

This account includes miscellaneous equipment associated with generation of power but are not included in other, more identifiable accounts.

The retirement rate analysis performed for this account included all transactions over the period of 1977 to 2017. However, this account has not witnessed material changes in the levels of additions and retirements since the last study. Retirement ratios shown on page 6-15 remain low with a high level of exposures at over 80 percent surviving, resulting in a truncated observed life table. Given the minor level of changes to the previous data set, there is no statistical reason to change from the previously approved estimated average service life based on the Iowa 51-R4 curve. Even though this is a broad category, data for similar peers show a life estimate in the 50-year range for this account.

Salvage data for recent retirements and costs of removal are trending above 10 percent as shown on page 7-6. The historical net salvage average as of the end of 2017 is negative 15 percent, with recent three-year averages ranging from negative 11 percent in 2010 to negative 68 percent in 2015.

Concentric recommends continuing to gradually increase salvage estimates from the lower negative 10 percent in the previous depreciation study, to negative 15 percent to reflect this trend.

ACCOUNT 353.00 – TRANSMISSION PLANT – SUBSTATION EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$232,046,270	12.26%	50-R4	50-R4	-25%	-25%

Substation equipment within the transmission group includes the cost installed of transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits.

Retirement rate analyses included accounting data from the period of 1975 to 2017. The original survivor curve plotted on page 6-28 shows small but consistent retirements beginning early in the assets' life and continuing at a consistent pace throughout the age intervals. The small amount of activity since the last study has reinforced the currently approved Iowa 50-R4 curve. This recommendation is consistent with peers in the transmission and distribution power industry, showing average service life estimates of 47 to 53 years for this account.

This account has not witnessed a significant amount of new net salvage data since the last study and although costs of removal remain above negative 25 percent, the trend has remained unchanged. Historical averages have been between negative 37 percent in 2009 to negative 57 percent in 2015 with the historical average as of 2017 being negative 53 percent. Reviews with operations personnel indicated that salvage and removal activity is expected to slow in the future, Concentric therefore recommends maintaining a net salvage percentage of negative 25 percent.

ACCOUNT 355.00 – TRANSMISSION PLANT – POLES, TOWERS AND FIXTURES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$111,154,687	5.87%	50-R1.5	50-R1.5	-25%	-35%

This account reflects the installed costs of electric transmission poles and towers. The associated components include guy wires, crossarms, brackets, insulators and excavation and backfill material used in the installation of these structures.

The retirement analyses included transactions from 1975 to 2017, with low but consistent retirement ratios through the accounts life as indicated on the original survivor curve as shown on page 6-28. This observed trend is consistent with the operation interviews which indicated that shorter lives can occur when temporary services related to highway construction are put in place and removed after a few years. Additionally, operations personnel indicated the program to replace pole and tower components is on-going, lasting for a minimum of 40 years. Fortis operations reported the use of steel stub supports for selected newer poles that show early signs of deterioration. This is part of a more active maintenance program meant to offset any decrease in service life. The statistical data and operating and maintenance practices reinforce maintaining the existing 50-R1.5 life estimate. The Iowa 50-R1.5 curve for this account sits in the middle of the range of industry peers.

Net salvage costs in the past five years have consistently increased as a ratio of original costs retired. The cost of removal data can be quite volatile due to the timing difference between retirements and removal of poles, and the differences in location and cost of getting to these poles. Smoothing this volatility results in recent net salvages of over negative 100 percent, as shown on page 7-28. The historical averages have been trending up, from negative 29% in 2010, to over negative 90% in 2017. In keeping with the gradual increase of salvage to reflect the ultimate costs of removal, Concentric recommends an estimate of net salvage to a more moderate level of negative 35 percent.

ACCOUNT 356.00 – TRANSMISSION PLANT – CONDUCTORS AND DEVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$108,270,947	5.72%	53-R1.5	51-R1.5	-25%	-30%

This account includes investment related to the overhead conductors and devices used at a transmission voltage. The components include the conductors, circuit breakers, insulating wires, cables and ground wires, and lightning arresters and associated switches.

All account transactions for the period 1975 through 2017 were analyzed by the retirement rate method. The original survivor curve as plotted on page 6-31 shows retirements in this account began at a relatively early age and continued at almost the same rate through the entire life of the account. The pace of retirements picks up somewhat after the 30-year age interval and presents a departure from the previously approved Iowa 53-R1.5 curve. In 2015 and 2016, almost $1 million of retirements at 30 to 60-year age intervals left lower percent surviving on the original survivor curve. Adjusting the survivor curve estimate to an Iowa 51-R1.5 decreased the RM from 0.2081 per the currently approved Iowa 53-R1.5 curve, to 0.1635, indicating a better recommended Iowa curve. Discussions with operations personnel noted a significant amount of retirements to conductors because of handling issues and risk to operators. Based on the statistical evidence and operating conditions, Concentric recommends an Iowa 51-R1.5 curve. This estimate is in the mid-range of similar plant conductors and services in the transmission industry.

This account has witnessed a significant amount of net salvage activity since 2010, amounting to just over 100 percent of original cost. The most recent three-year moving average points to a net salvage estimate more negative than 140 percent (page 7-9) and the historical average at approximately negative 100 percent. Considering the currently approved net salvage recommendation of negative 25 percent, Concentric recommends a moderated change to a more negative 30 percent at this time.

ACCOUNT 360.2 – DISTRIBUTION PLANT – SURFACE AND MINERAL

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$11,319,973	.60%	75-R4	75-R4	0%	0%

This account pertains to the payments made to access and maintain rights to land corridors or rights-of-ways at the distribution level.

No retirement rate analysis was conducted on this account as there have been no retirements since additions were made in 1960. Concentric views that a reasonable approach is to align the life of this account to the longest useful life of the assets that need land access. Distribution level access would be closely associated with the power generation and transmission accounts which have typical maximum lives of 75 years. Industry practice would be to assign a right high modal curve of R4. Concentric would therefore recommend continuing to use the previously approved 75-R4 curve.

ACCOUNT 362.0 – DISTRIBUTION PLANT – SUBSTATION EQUIPMENT

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$242,053,748	12.79%	50-R3	50-R3	-25%	-30%

This account includes the station equipment related to electric distribution service. Components include control equipment, transformers, switches, cooling equipment and ducting in the substation at the lower distribution level.

The retirement rate analyses completed by Concentric reviewed all transactions in the account between 1975 and 2017. While the account has experienced almost $9 million of retirements, only $700,000 has been incurred since 2014, and their impact did not materially alter the original survivor curve approved in the last study. The historical data presents no basis for a departure from the previously approved Iowa 50-R3 curve. Discussions with Company operations and engineering staff indicated that the historical indications provide a reasonable future expectation for the equipment in this account. The peer analysis shows that an Iowa 50-R3 curve is common for this account. Based on the data presented and discussions with staff as to future expectations, Concentric recommends continuing to use the Iowa 50-R3 as an estimate the future retirement pattern for this account.

The distribution substation equipment in this account has experienced significant amount of costs of removal as a percentage of the retired value. As shown on page 7-10, the costs of removal over the past three years are consistently over 50 percent and trending over 40 percent historically. The peers for this account show similar costs of removal. While Concentric notes that a larger increase is warranted based on the historic data, a gradual change of net salvage to a more negative 30 percent is recommended.

ACCOUNT 364.00 – DISTRIBUTION PLANT – POLES, TOWERS AND FIXTURES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$205,785,491	10.87%	50-R2.5	50-R3	-30%	-35%

This account reflects the installed costs of poles or towers and support fixtures that carry overhead conductors at a distribution level. Equipment in this account includes guy wires, crossarms, brackets and the excavation and backfill of materials associated with their installation.

The retirement rate analysis included all transactions in the account between 1975 and 2017. A material amount of retirements has occurred since 2014, with over $1 million of retirements experienced since the last study. This represents approximately 13 percent of the total retirements in this account. The original survivor curve shown on page 6-43 shows low retirement ratios occurring in the earlier age intervals and then gradually increasing after the 27-year age interval. The data shows a better statistical fit with an Iowa 50-R3 with a lower residual measure of 0.7461 than the 0.8079 RM associated with the previously approved Iowa 50-R2.5. Engineering staff discussions point to the larger retirements at ages 53.5 to 56.5 (page 6-41) as reasonable and relate to the feeder lines retired in the Kootenays. The Iowa curve change from the R2.5 to R3 reflects the more abrupt retirements because of PCB standards for transformers. Based on the statistical fit to the data as well as engineering staff input, Concentric recommends a revised estimate of the Iowa 50-R3.

Net salvage costs in poles towers and fixtures have increased since 2008. The analysis presented on page 7-11, shows the most recent historical and five-year net salvages at over negative 100 percent. Some of the volatility in the net salvage costs reflect timing differences of when poles are removed after retirement. The trend has been to more negative net salvage percentage with individual net salvage indications in some years ranging from negative 69 percent (2013) to negative 325 percent (2015). Retirements in this account can be caused by storm damage which add to the volatility in the net salvage data. Given the gradual increases to net salvage percentages, Concentric recommends revising the estimate of net salvage in this account to a more negative 35 percent.

ACCOUNT 365.00 – DISTRIBUTION PLANT – CONDUCTORS AND DEVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$332,124,926	17.54%	49-R3	55-R2.5	-30%	-35%

This account reflects the installed costs of distribution overhead conductors. The components include pole top circuit breakers, conductors, ground wires, insulators, lightning arresters and associated tie wires or clamps.

All transactions between 1975 and 2017 were analyzed using the retirement rate analysis. There are a significant amount of retirements that have been experienced, providing enough historical data to conduct statistical analyses. In discussions with Fortis engineering staff, nameplate life spans for overhead conductors were as long as 80 years, while operations staff expectations were 65 years of life. As conductors is only one component of the asset class which also includes other shorter-life equipment, the Company expects that an average service life of less than 65 years is appropriate. Peer indications for this account show life estimates that range from 40 years to 65 years. Recent retirements incurred since 2014, are over $2 million. The historical data points to a better statistical fit to an Iowa 55 R2.5 with a RM of 0.1689. As a comparison, the RM that results from the previously approved Iowa 49-R3 curve is 0.5646. Based on these considerations, Concentric recommends an Iowa 55-R2.5 average life estimate for this account.

Net salvage costs in the last five years and three years have been averaging more negative than 100 percent and negative 200 percent, respectively as indicated at page-7-12. The three-year and five-year averages have been increasing up to be more negative than 200 percent and over negative 180, respectively, as of the end of 2017. The data indicates net salvage costs for distribution conductors and devices are significantly more negative than the same types of devices at the transmission level. Operations staff confirmed that cost of removal percentages for distribution conductors are not necessarily the same as experienced for transmission conductors. To reflect the higher costs that this account is experiencing, while recognizing the need to introduce these changes gradually, Concentric recommends a net salvage percentage of negative 35 percent.

ACCOUNT 368.00 – DISTRIBUTION PLANT – LINE TRANSFORMERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$152,641,438	8.06%	45-R4	42-R3	-15%	-25%

This account reflects the installed costs of distribution line transformers, either overhead or underground, as well as voltage regulators. Components of these costs include the transformer cut-out boxes, capacitors, transformer lightning arrestors and the labour associated with their installation.

The retirement rate analysis included all transactions in the account between 1975 and 2017. Of the almost $18 million of retirements that have been experienced since 1975, almost 25 percent, or $4 million, have been incurred since 2015. The original survivor curve shown on page 6-49 shows low retirement ratios occurring in the earlier age intervals, gradually increasing after the 30-year age interval. The more recent data shows a better statistical fit with an Iowa 42-R3, with a RM of 0.8912 which compares to the previously approved Iowa 45-R4 residual measure of 1.3631. Industry peers have service lives ranging from 27 to 48 years with varying conditions and maintenance policies. Based on the statistical fit with a retirement rate analyses and considering peer averages, Concentric recommends an Iowa 42-R3 average service life curve.

Net salvage costs in the last five years and three years have been averaging more negative than 30 percent and negative 40 percent as indicated on page 7-13. The data indicates net salvage costs for distribution line transformers are tracking significantly more negative than the previously approved negative 15 percent. For example, the historical averages are at negative 32 percent as of the end of 2017 and the three year averages reduced from their peak of negative 55 percent in 2012 but are still at negative 47 percent as of the end of 2017. Concentric recommends a moderated net salvage estimate of negative 25 percent to approach more recent three-year averages.

ACCOUNT 369.00 – DISTRIBUTION PLANT – SERVICES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$9,521,831	0.50%	75-R4	75-R4	0%	0%

This account includes the installed costs of distribution conductors, either overhead or underground, that span from the distribution primary feeder through to the customers' meters. This includes the conduit, cables, wires, insulators and municipal inspection services that may be incurred.

A retirement rate analyses on this account was based on all transactions from 1980 to 2017. The retirements experienced in this account have all been experienced prior to 2014. As shown in the original survivor curve on page 6-52, there have been few retirements with most retirements concentrated in the 4.5-year age interval. This is not enough data to statistically fit a survivor curve. A comparison of peer distribution level services has a limited range with which to compare. Services are typically not replaced unless new construction requires the movement of already installed customer lines. Concentric would therefore recommend keeping the previously approved 75-R4, pending any new data justifying a new estimate.

Distribution plant services have had no retirement and cost of removals recorded that can result in any net salvage for this account. As a result, net salvage has been estimated as zero percent.

ACCOUNT 370.10 – DISTRIBUTION PLANT – AMI METERS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$37,460,898	1.98%	20-SQ	18-SQ	0%	0%

This account includes the costs of installing digital advanced metering infrastructure ("AMI") that contains automatic meter reading functionality. It is a relatively new technology that allows real-time data acquisition with metering endpoints. The Federal Energy Regulatory Commission defines AMI as "a metering system that records customer consumption hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point." While this account is a recent addition to the Company's metering assets, with additions beginning in 2015 and continuing into 2017, it still comprises almost two percent of total plant original cost.

There have been no retirements to this account. As a result, a retirement rate analysis cannot be used to estimate a survivor curve. Concentric is relying on industry trends with AMI technology as well as consultations with Company engineering and operations staff to ascertain an estimate of AMI average life. A large piece of AMI service life is based on meter testing prescribed by Measurement Canada. At present, it is assumed that an 18-SQ curve would align with testing intervals and anticipated obsolescence. As retirement and testing data is collected, adjustments can be made to this preliminary estimate. There have been no salvage costs associated with this account and Concentric anticipates no net salvage at this point.

ACCOUNT 373.00 – STREET LIGHTING AND SIGNAL SYSTEMS

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$12,576,523	0.66%	27-L2	25-R2	-10%	-15%

This asset reflects the costs of installing street lighting equipment used for public street or highway traffic lighting. The components may be buried or overhead conductors, insulating materials, trenching, insulators, lamps and municipal inspection services associated with street lighting.

All transactions from 1976 to 2017 were considered in the retirement rate analysis. Of the total retirements experience in the account, $1.5 million of the total $1.7 million occurred prior to 2015. The original survivor curve on page 6-60 shows very low retirements early in the life of the account but higher amounts starting in the age intervals 15 to 35. An Iowa 25-R2 curve captures more of these mid-life retirements with a similar RM of 0.4278 as the previously approved Iowa 27-L2 which produced a RM of 0.4139. The fact that both the previously approved curve and the current best fit are low modes of 2 (L2 and R2) means that there is not a significant shift in the steepness of the curves. As both curves under consideration had similar RM, the R2 curve was chosen because it was a better visual fit.

The right mode curve indicates the mode is to the right of, or higher than, the average age of the population of street lights. Operations and engineering staff indicated that steel poles are standard for street lighting.

A more thorough explanation of the statistical explanations of left and right modal curves is found in Section 9 of this report. Industry peers that own street lighting equipment exhibit right modal curves that range from 20 to 40 years. Concentric is therefore recommending a survivor curve of Iowa 25-R2 based on statistical and visual fit of the retirement rates as well as industry expectations.

The latest net salvage data for the last five years has an average of negative 30 percent with no recent cost of removal (page 7-14). Although there has been little salvage activity in the last few years, the data points to net salvage costs for street lights tracking significantly more negative than the previously approved negative 10 percent. Historical averages peaked in 2011 to negative 43 percent and have dropped to negative 30 percent as of the end of 2017. Concentric recommends a gradual change of net salvage estimate to negative 15 percent, as previously indicated in order to move closer to expected net salvage costs.

ACCOUNT 390.10 – GENERAL PLANT – STRUCTURES MASONRY

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$43,491,688	2.30%	41-S3	35-S1	0%	-5%

This account includes any masonry structures or improvements used for general purposes and not directly for specific generation or operations purposes. The components may be the buildings, fencing, landscaping, sewage, roads and any associated improvements.

The retirement rate analysis considered all plant masonry structures or improvements installed between 1940 and 2017, and retirement data up to 2015. A fit to observed data indicated that the currently approved Iowa 41-S3 has been replaced by a better fit curve of 35-S1 with a RM of 0.5589 (page 6-63) as compared to the previously approved Iowa 41-S3 curve which has a residual measure of 0.9805. A 35-year average life is inside the 20 to 50-year range of Canadian peers in the same industry. Concentric therefore recommends a 35-S1 estimate of average life based on a better statistical fit to the observed data.

Net salvage data for the Structures Masonry account has been very sparse as shown on page 7-15. As operations is expecting further costs to older buildings in the near future, Concentric recommends a negative five percent net salvage to prepare for more costs of removal.

ACCOUNT 392.20 – GENERAL PLANT - HEAVY DUTY VEHICLES

Investment $	Investment %	Previously Approved Curves	Concentric Recommends Curves	Previously Approved Salvage	Concentric Recommends Salvage
$22,388,898	1.18%	15-L3	16-L2.5	25%	15%

The equipment in General Plant – Heavy Duty Vehicles are bigger trucks and rolling equipment used in heavier duty environments. The retirement rate analysis reviewed all retirements since 1990. With retirements at slightly higher age intervals, the most recent five years would seem to be more representative of how vehicles in this category would be replaced. Retirements since the last study were almost $2.4 million which provided a better fit to an Iowa 16-L2.5 curve, as summarized on page 6-65 with a lower residual measure of 0.3895. By comparison, the previously approved 15-L3 curve for this account had an RM of 0.5815. A peer comparison showed a range of 10 to 17 years. Concentric recommends a 16-L2.5 Iowa curve for the Heavy Duty Vehicles account based on statistical fit to recent historical measures, a high level peer comparison and an acknowledgement with FortisBC staff that it would be a more realistic expectation of future retirements.

The previous depreciation study included a net salvage estimate of 25 percent. Recent data point to lower gross salvage proceeds combined with no costs of removal resulting in a reduction in the recent five-year and three-year moving averages of net salvage to 15 percent and six percent, respectively. FortisBC management discussions acknowledge that a lower net salvage number would be more reflective of how Heavy Duty Vehicles could get longer service lives. As a result, Concentric is recommending a 15 percent net salvage for Heavy Duty Vehicles.

3.2.2.1 Other Accounts

The above analysis provides the consideration relating to over 90 percent of the depreciable plant considered. The accounts related to the remaining depreciable plant studied, as of December 31, 2017, were analyzed using similar methods and considered similar factors. These accounts include Generation Land Rights, (330.10), Transmission Surface and Mineral (350.20) and Transmission Roads and Trails (359.00).

SECTION 4

4 CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

4.1 Group Depreciation Procedures

When more than a single item of property is under consideration, a group procedure for depreciation is appropriate because (normally) all of the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, the Average Life Group and Equal Life Group procedures.

In the Average Life Group procedure, the rate of annual depreciation is based on the average service life of the group - this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to the average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the Equal Life Group procedure, also known as the unit summation procedure, the property group is subdivided according to service life. That is, each equal life group includes that portion of the property which experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life unit.

In the determination of the depreciation rates in this study, the use of the Average Life Group procedure has been continued. While the Equal Life Group procedure provides an enhanced matching of depreciation expense to the consumption of service value, the Average Life Group procedure was used in order to conform to past Company practices and approvals by the BCUC.

4.2 Calculation of Annual and Accrued Amortization

Amortization is the gradual extinguishment of an amount in an account by distributing such amounts over the life of the asset to which it is expected to apply. The distribution of the amount is in equal amounts to each year of the amortization period.

Group systems of accounting depreciation is one of two systems used to determine depreciation of assets. The other is the unit system of accounting depreciation where depreciation is calculated for large, identifiable pieces of equipment that are easy to identify, have a lot of capital in each unit and are rather unique[3]. Examples include large excavators, a large reservoir or large dam.

The group system chooses to combine several similar units that are smaller into groups which then are analyzed according to their common traits. Examples include many individual meters, transformers or similar substation equipment that would share the same life span, cost of removal and dispersion of retirements. The assets in group accounting are often tracked as soon as one item

[3] Anson Marston, R. W., *Engineering Valuation and Depreciation* (Iowa State University Press,1982), 224

is purchased, and then retired when the asset being removed from service. All of this takes some effort but leads to the ultimate dispersion of retirements and retirement rate analyses.

Within the group system of accounting, there are classes of equipment that are very numerous but represent a small portion of overall depreciable plant. Tracking the individual purchases and retirements of each item in the class would require effort and cost that would not be justified in relation to the level of accuracy in the results. Even if such an effort was optimized and made effective, sometimes retirements of small items in the group would be missed. Examples may include the many pieces of furniture, computer hardware, software licenses, communication equipment and small tools. The system would depend on utilization and retirement notifications of disparate small items and entries to ensure surviving balances of old vintages are still in service.

To minimize this extra cost to the rate payers and estimation and notification errors, amortization accounting places an estimated life span to the entire class and automatically retires the asset at the end of a selected amortization period. This takes group accounting to a higher, more simplified level by treating all items belonging to a certain vintage year as one asset. Rather than tracking the many individual parts through their acquisition and retirements through labour intensive notifications and accounting entries, amortization accounting simplifies retirements while still adhering to proper depreciation principles.

For example, in the case of computer equipment, all the equipment put into service in any specific year is treated as an individual asset. Given that Concentric has estimated an eight-year life for computer equipment, all of the investment introduced for 2009 is treated and tracked as one asset and is all retired automatically at the end of 2016, being the end of the eight-year amortization period. The 2009 vintage original cost is retired along with accumulated depreciation regardless of whether equipment is still in service or not. A further simplification is that no retirements are made from the 2009 vintage until 2016 even if the equipment comes out of service before 2016. In this manner, there is no requirement for any retirement notification process for the accounts where amortization accounting is proposed. The conversion to amortization accounting is made for a selected few accounts, where the individual dollar amount of any given asset is low, and where there is a large amount of these low dollar value assets.

Concentric continues to recommend the practice of using amortization accounting for selected accounts (mainly general plant accounts) because of the disproportionate plant accounting effort required when compared to the large number of small cost items in these accounts as discussed above. Many regulated utilities in North America have received approval to adopt amortization accounting for these types of accounts. FortisBC also proposed amortized accounting for selected accounts in their 2015 study, for balances as of December 31, 2014, on pages III-3, IV-4 and IV-5 of the 2014 Depreciation Study dated August 21, 2015. These recommendations were accepted by the British Columbia Utilities Commission but were not fully implemented by FortisBC.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is proposed for the following accounts:

Account	Title	Amortization Period in Years
370.10	AMI Meters	18
391.00	Office Furniture and Equipment	15
391.10	Computer Hardware	4
391.20	Computer Software	8
391.60	AMI Computer Software	10
394.00	Tools and Work Equipment	15
397.00	Communications Structures and Equipment	15
397.10	Fiber	15
397.20	Communications Structures and Equipment	15

For calculating annual amortization amounts, as of December 31, 2017, the book depreciation reserve for each plant account or subaccount is assigned or allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. Any amount of book reserve in vintages older than the amortization period has been deducted from both the original cost as well as from accumulated depreciation. This approach assumes that the original costs of vintages, older than the chosen amortization period, will have been retired along with their accumulated depreciation.

The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age, to its amortization period. An annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

SECTION 5

5 RESULTS OF THE STUDY

5.1 Qualification of Results

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and salvage and for the change of the composition of property in service. The annual accrual rates and the accrued depreciation were calculated in accordance with the Straight-Line method, using the average life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

5.2 Description of Detailed Tabulations

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in Section 6 of this report.

For each depreciable group analyzed by the Retirement Rate method, a chart depicting the original and estimated survivor curves followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which were plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2017 are presented in account sequence in Section 8 of the supporting documents. The tables indicate the estimated average survivor curves used in the calculations. The tables set forth, for each installation year, the original cost, calculated accrued depreciation and the calculated annual accrual.

FortisBC - Electricity

TABLE 1. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

Account	Account Description	Survivor Curve	Net Salvage Percent	Original Cost as of Dec. 31, 2017	Book Depreciation Reserve	Future Accruals	Calculated Annual Accural Amount	Calculated Annual Accural Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GENERATION PLANT									
330.10	Land Rights	75-R4	-	961,358	299,354	662,004	10,280	1.07	62.45
331.00	Structures and Improvements	60-S1.5	-	18,215,444	5,960,868	12,254,577	250,849	1.38	47.50
332.00	Reservoirs, Dams and Waterways	70-S2	-	33,991,864	7,872,047	26,119,817	478,121	1.41	54.46
333.00	Water Wheels, Turbines and Generators	70-R2.5	-	97,569,107	19,065,547	78,503,560	1,325,776	1.36	58.78
334.00	Accessory Electrical Equipment	40-R2.5	-	43,137,705	12,485,347	30,652,358	971,673	2.25	29.81
335.00	Other Power Plant Equipment	51-R4	-	45,020,063	14,997,747	30,022,316	789,305	1.75	37.47
336.00	Roads, Railroads and Bridges	75-R4	-	1,287,434	383,764	903,671	18,503	1.44	49.18
TOTAL GENERATION PLANT				**240,182,976**	**61,064,673**	**179,118,302**	**3,844,507**	**1.60**	
TRANSMISSION PLANT									
350.20	Surface and Mineral	75-R4	-	8,173,036	1,949,689	6,223,347	103,540	1.27	59.50
353.00	Substation Equipment	50-R4	-	232,046,270	77,149,534	154,896,736	3,892,666	1.68	38.19
355.00	Poles, Towers and Fixtures	50-R1.5	-	111,154,687	34,675,315	76,479,372	1,827,246	1.64	40.34
356.00	Conductors and Devices	51-R1.5	-	108,270,947	27,787,869	80,483,078	1,918,367	1.77	41.08
359.00	Roads and Trails	50-R3	-	1,121,930	305,009	816,920	22,011	1.96	36.97
TOTAL TRANSMISSION PLANT				**460,766,869**	**141,867,417**	**318,899,452**	**7,763,831**	**1.68**	
DISTRIBUTION PLANT									
360.20	Surface and Mineral	75-R4	-	11,319,973	2,221,637	9,098,336	140,947	1.25	63.79
362.00	Substation Equipment	50-R3	-	242,053,748	64,436,898	177,616,850	4,449,122	1.84	39.17
364.00	Poles, Towers and Fixtures	50-R3	-	205,785,491	62,141,795	143,643,696	3,604,877	1.75	38.23
365.00	Conductors and Devices	55-R2.5	-	332,124,926	100,599,146	231,525,780	5,123,988	1.54	43.23
368.00	Line Transformers	42-R3	-	152,641,438	36,965,463	115,675,976	3,520,348	2.31	32.61
369.00	Services	75-R4	-	9,521,831	6,635,598	2,886,233	48,950	0.51	50.87
370.10	AMI Meters	18-SQ	-	37,460,898	128,100	37,332,798	2,342,234	6.25	15.97
371.00	Installations on Customers' Premises	20-R1	-	937,832	937,832	0	0	0.00	4.77
373.00	Street Lighting and Signal Systems	25-R2	-	12,576,523	4,133,011	8,443,512	510,418	4.06	16.58
TOTAL DISTRIBUTION PLANT				**1,004,422,661**	**278,199,479**	**726,223,182**	**19,740,883**	**1.97**	
GENERAL PLANT									
390.10	Structures - Masonry	35-S1	-	43,491,688	9,820,941	33,670,747	1,029,462	2.37	30.53
390.20	Operations Buildings	50-R4	-	14,502,893	5,779,689	8,723,204	218,004	1.50	39.09
391.00	Office Furniture and Equipment	15-SQ	-	5,632,481	2,378,475	3,254,006	248,738	4.42	9.69
391.10	Computer Hardware	4-SQ	-	11,842,939	4,030,066	7,812,872	2,557,789	21.60	2.83
391.20	Computer Software	8-SQ	-	36,720,287	18,362,561	18,357,726	3,291,881	8.96	4.62
391.60	AMI Computer Software	10-SQ	-	9,597,410	2,432,856	7,164,554	959,741	10.00	7.47
392.10	Light Duty Vehicles	12-L1	15	4,769,889	2,122,685	1,931,721	228,532	4.79	8.06
392.20	Heavy Duty Vehicles	16-L2.5	15	22,388,898	4,173,998	14,856,565	1,454,716	6.50	10.78
394.00	Tools and Work Equipment	15-SQ	-	8,808,650	5,308,325	3,500,325	361,994	4.11	7.48
397.00	Communications Structures and Equipment	15-SQ	-	13,110,863	9,684,203	3,426,660	372,367	2.84	6.16
397.10	Fiber	15-SQ	-	11,995,587	7,492,415	4,503,172	835,744	6.97	5.53
397.20	AMI Communications Structure and Equipment	15-SQ	-	4,969,732	736,552	4,233,180	331,286	6.67	12.78
TOTAL GENERAL PLANT				**187,831,317**	**72,322,767**	**111,434,732**	**11,890,254**	**6.33**	
TOTAL DEPRECIABLE PLANT				**1,893,203,823**	**553,454,336**	**1,335,675,669**	**43,239,476**	**2.28**	
PLANT NOT STUDIED									
114.00	Utility Plant Acquisition Adjustment			11,912,000	6,328,225				
350.10	Land Rights Transmission								
360.10	Land Rights Distribution								
360.20	Distribution Station Equipment - Non-Regulated			65,734	16,069				
370.00	Meters			53,370	-730,113				
389.00	Land			11,155,845	-11,145				
390.90	Leasehold Improvements			2,857,393	2,535,177				
999.90	Contribution in Aid of Construction			-187,804,927	-67,992,749				
107.10	Work-In-Progress - Asset Management			20,877,961					
TOTAL NON - DEPRECIABLE PLANT				**-140,882,623**	**-59,854,536**				
TOTAL PLANT				**1,752,321,200**	**493,599,799**	**1,335,675,669**	**43,239,476**		

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TABLE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2017

DEPRECIATION RELATED TO RECOVERY OF COST OF REMOVAL

Account	Account Description (1)	Survivor Curve (2)	Net Salvage Percent (3)	Original Cost as of Dec. 31, 2017 (4)	Book Depreciation Reserve (5)	Future Accruals (6)	Calculated Annual Accural Amount (7)	Calculated Annual Accural Rate (8)	Composite Remaining Life (9)
GENERATION PLANT									
330.10	Land Rights	75-R4	0	961,358	0	0	0	0.00	62.45
331.00	Structures and Improvements	60-S1.5	-10	18,215,444	-617,306	2,438,850	54,622	0.30	47.50
332.00	Reservoirs, Dams and Waterways	70-S2	-25	33,991,864	-34,765	8,532,731	165,379	0.49	54.46
333.00	Water Wheels, Turbines and Generators	70-R2.5	-25	97,569,107	443,911	23,948,366	417,250	0.43	58.78
334.00	Accessory Electrical Equipment	40-R2.5	-20	43,137,705	-23,432	8,650,973	377,934	0.88	29.81
335.00	Other Power Plant Equipment	51-R4	-15	45,020,063	649,734	6,103,275	164,697	0.37	37.47
336.00	Roads, Railroads and Bridges	75-R4	0	1,287,434	0	0	0	0.00	49.18
TOTAL GENERATION PLANT				**240,182,976**	**418,142**	**49,674,195**	**1,179,882**	**0.49**	
TRANSMISSION PLANT									
350.20	Surface and Mineral	75-R4	0	8,173,036	0	0	0	0.00	59.50
353.00	Substation Equipment	50-R4	-25	232,046,270	2,976,608	55,034,959	1,506,680	0.65	38.19
355.00	Poles, Towers and Fixtures	50-R1.5	-35	111,154,687	631,430	38,272,711	979,685	0.88	40.34
356.00	Conductors and Devices	51-R1.5	-30	108,270,947	504,336	31,976,949	813,503	0.75	41.08
359.00	Roads and Trails	50-R3	0	1,121,930	0	0	0	0.00	36.97
TOTAL TRANSMISSION PLANT				**460,766,869**	**4,112,373**	**125,284,619**	**3,299,869**	**0.72**	
DISTRIBUTION PLANT									
360.20	Surface and Mineral	75-R4	0	11,319,973	0	0	0	0.00	63.79
362.00	Substation Equipment	50-R3	-30	242,053,748	2,882,028	69,734,096	1,870,644	0.77	39.17
364.00	Poles, Towers and Fixtures	50-R3	-35	205,785,491	1,466,460	70,558,461	2,019,952	0.98	38.23
365.00	Conductors and Devices	55-R2.5	-35	332,124,926	2,866,696	113,377,028	2,791,466	0.84	43.23
368.00	Line Transformers	42-R3	-25	152,641,438	216,531	37,943,828	1,244,320	0.82	32.61
369.00	Services	75-R4	0	9,521,831	0	0	0	0.00	50.87
370.10	AMI Meters	18-SQ	0	37,460,898	0	0	0	0.00	15.97
371.00	Installations on Customers' Premises	20-R1	0	937,832	0	0	0	0.00	4.77
373.00	Street Lighting and Signal Systems	25-R2	-15	12,576,523	127,747	1,758,731	111,634	0.89	16.58
TOTAL DISTRIBUTION PLANT				**1,004,422,661**	**7,559,463**	**293,372,145**	**8,038,016**	**0.80**	
GENERAL PLANT									
390.10	Structures - Masonry	35-S1	-5	43,491,688	-14,135	2,188,719	70,600	0.16	30.53
390.20	Operations Buildings	50-R4	-5	14,502,893	0	725,145	18,814	0.13	39.09
391.00	Office Furniture and Equipment	15-SQ	0	5,632,481	0	0	0	0.00	9.69
391.10	Computer Hardware	4-SQ	0	11,842,939	0	0	0	0.00	2.83
391.20	Computer Software	8-SQ	0	36,720,287	0	0	0	0.00	4.62
391.60	AMI Computer Software	10-SQ	0	9,597,410	0	0	0	0.00	7.47
392.10	Light Duty Vehicles	12-L1	15	4,769,889	345,827	-345,827	-46,507	-0.98	8.06
392.20	Heavy Duty Vehicles	16-L2.5	15	22,388,898	0	0	0	0.00	10.78
394.00	Tools and Work Equipment	15-SQ	0	8,808,650	0	0	0	0.00	7.48
397.00	Communications Structures and Equipment	15-SQ	0	13,110,863	-344,399	344,399	78,157	0.60	6.16
397.10	Fiber	15-SQ	0	11,995,587	0	0	0	0.00	5.53
397.20	AMI Communications Structure and Equipment	15-SQ	0	4,969,732	0	0	0	0.00	12.78
TOTAL GENERAL PLANT				**187,831,317**	**-12,707**	**2,912,436**	**121,064**	**0.06**	
TOTAL DEPRECIABLE PLANT				**1,893,203,823**	**12,077,272**	**471,243,395**	**12,638,831**	**0.67**	
PLANT NOT STUDIED									
114.00	Utility Plant Acquisition Adjustment			11,912,000	6,328,225	0			
350.10	Land Rights Transmission					0			
360.10	Land Rights Distribution					0			
360.20	Distribution Station Equipment - Non-Regulated			65,734	16,069	0			
370.00	Meters			53,370					
389.00	Land			11,155,845	-11,145	0			
390.90	Leasehold Improvements			2,857,393	2,535,177	0			
999.90	Contribution in Aid of Construction			-187,804,927	-67,992,749	0			
107.10	Work-In-Progress - Asset Management			20,877,961		0			
TOTAL NON - DEPRECIABLE PLANT				**-140,882,623**	**-59,124,423**	**0**			
TOTAL PLANT				**1,752,321,200**	**-47,047,151**	**471,243,395**	**12,638,831**		

SECTION 6

6 RETIREMENT RATE ANALYSIS

FortisBC - Electricity

Account #: 330.10 - Land Rights Generation

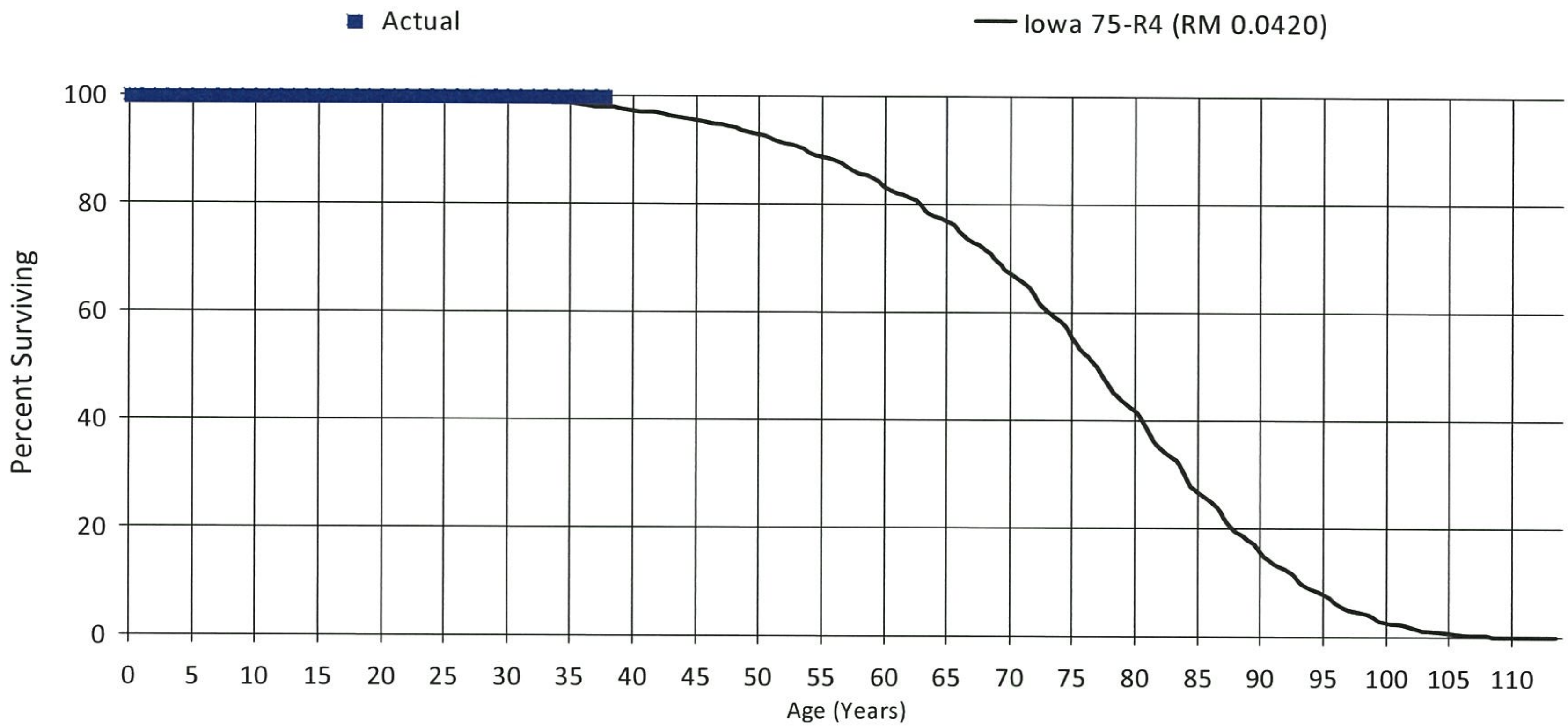
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	961,358	0	0.0000	1.0000	100.00
0.5	961,358	0	0.0000	1.0000	100.00
1.5	961,358	0	0.0000	1.0000	100.00
2.5	961,358	0	0.0000	1.0000	100.00
3.5	961,358	0	0.0000	1.0000	100.00
4.5	961,358	0	0.0000	1.0000	100.00
5.5	961,358	0	0.0000	1.0000	100.00
6.5	961,358	0	0.0000	1.0000	100.00
7.5	961,358	0	0.0000	1.0000	100.00
8.5	961,358	0	0.0000	1.0000	100.00
9.5	846,775	0	0.0000	1.0000	100.00
10.5	119,897	0	0.0000	1.0000	100.00
11.5	119,897	0	0.0000	1.0000	100.00
12.5	98,939	0	0.0000	1.0000	100.00
13.5	98,939	0	0.0000	1.0000	100.00
14.5	98,939	0	0.0000	1.0000	100.00
15.5	98,939	0	0.0000	1.0000	100.00
16.5	98,939	0	0.0000	1.0000	100.00
17.5	98,939	0	0.0000	1.0000	100.00
18.5	98,939	0	0.0000	1.0000	100.00
19.5	98,939	0	0.0000	1.0000	100.00
20.5	98,939	0	0.0000	1.0000	100.00
21.5	98,939	0	0.0000	1.0000	100.00
22.5	98,939	0	0.0000	1.0000	100.00
23.5	98,939	0	0.0000	1.0000	100.00
24.5	98,939	0	0.0000	1.0000	100.00
25.5	98,939	0	0.0000	1.0000	100.00
26.5	98,939	0	0.0000	1.0000	100.00
27.5	98,939	0	0.0000	1.0000	100.00
28.5	98,939	0	0.0000	1.0000	100.00
29.5	98,939	0	0.0000	1.0000	100.00
30.5	98,939	0	0.0000	1.0000	100.00
31.5	98,939	0	0.0000	1.0000	100.00
32.5	98,939	0	0.0000	1.0000	100.00
33.5	98,939	0	0.0000	1.0000	100.00
34.5	83,965	0	0.0000	1.0000	100.00
35.5	83,965	0	0.0000	1.0000	100.00
36.5	83,965	0	0.0000	1.0000	100.00
37.5	0	0	0.0000	0.0000	100.00

FortisBC - Electricity

Account #: 330.10 - Land Rights Generation

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 331.00 - Structures and Improvements

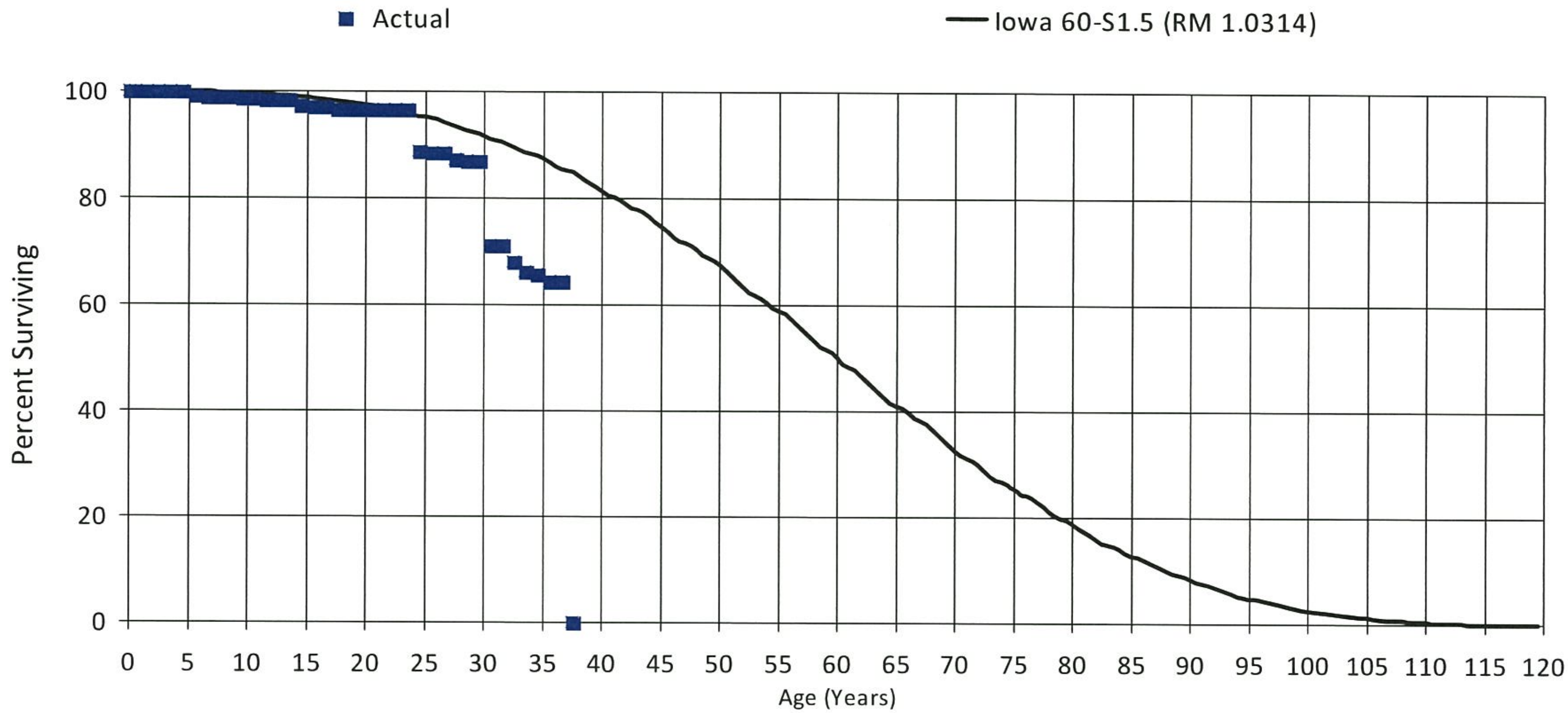
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	18,969,547	5	0.0000	1.0000	100.00
0.5	17,832,721	2	0.0000	1.0000	100.00
1.5	16,696,619	0	0.0000	1.0000	100.00
2.5	15,360,772	1	0.0000	1.0000	100.00
3.5	14,459,151	24	0.0000	1.0000	100.00
4.5	14,282,974	101,831	0.0071	0.9929	100.00
5.5	13,257,402	27,959	0.0021	0.9979	99.29
6.5	13,073,232	3,658	0.0003	0.9997	99.08
7.5	12,473,621	24,712	0.0020	0.9980	99.05
8.5	12,153,461	4,112	0.0003	0.9997	98.85
9.5	11,377,393	7,531	0.0007	0.9993	98.82
10.5	10,748,854	20,649	0.0019	0.9981	98.75
11.5	10,510,776	10,523	0.0010	0.9990	98.56
12.5	10,098,902	8,326	0.0008	0.9992	98.46
13.5	9,880,627	109,018	0.0110	0.9890	98.38
14.5	9,304,434	12,106	0.0013	0.9987	97.29
15.5	8,919,226	0	0.0000	1.0000	97.16
16.5	7,897,835	39,184	0.0050	0.9950	97.16
17.5	7,393,680	0	0.0000	1.0000	96.68
18.5	7,323,376	2,932	0.0004	0.9996	96.68
19.5	6,865,016	0	0.0000	1.0000	96.64
20.5	6,770,320	0	0.0000	1.0000	96.64
21.5	6,614,146	0	0.0000	1.0000	96.64
22.5	4,428,978	0	0.0000	1.0000	96.64
23.5	3,025,207	247,630	0.0819	0.9181	96.64
24.5	1,617,333	3,630	0.0022	0.9978	88.73
25.5	1,346,105	0	0.0000	1.0000	88.53
26.5	535,021	7,026	0.0131	0.9869	88.53
27.5	431,972	1,634	0.0038	0.9962	87.37
28.5	401,300	0	0.0000	1.0000	87.04
29.5	380,443	69,778	0.1834	0.8166	87.04
30.5	295,024	0	0.0000	1.0000	71.08
31.5	238,461	10,451	0.0438	0.9562	71.08
32.5	199,122	4,865	0.0244	0.9756	67.96
33.5	190,599	1,489	0.0078	0.9922	66.30
34.5	189,110	4,096	0.0217	0.9783	65.78
35.5	30,931	0	0.0000	1.0000	64.36
36.5	30,931	30,931	1.0000	0.0000	64.36
37.5	0	0	0.0000	0.0000	0.00

FortisBC - Electricity

Account #: 331.00 - Structures and Improvements

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1950 - 2017



FortisBC - Electricity

Account #: 332.00 - Reservoirs, dams and waterways

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	34,996,427	0	0.0000	1.0000	100.00
0.5	34,346,179	8,191	0.0002	0.9998	100.00
1.5	33,659,855	13	0.0000	1.0000	99.98
2.5	32,669,769	859	0.0000	1.0000	99.98
3.5	30,504,567	6	0.0000	1.0000	99.98
4.5	30,272,527	145	0.0000	1.0000	99.98
5.5	28,191,685	108	0.0000	1.0000	99.98
6.5	27,486,228	23,135	0.0008	0.9992	99.98
7.5	25,253,997	3,130	0.0001	0.9999	99.90
8.5	23,702,307	1	0.0000	1.0000	99.89
9.5	20,215,914	2,949	0.0002	0.9999	99.89
10.5	18,024,232	2,491	0.0001	0.9999	99.88
11.5	15,124,369	8,049	0.0005	0.9995	99.87
12.5	14,872,898	14	0.0000	1.0000	99.82
13.5	13,768,512	0	0.0000	1.0000	99.82
14.5	12,920,746	67,547	0.0052	0.9948	99.82
15.5	12,853,199	88	0.0000	1.0000	99.30
16.5	14,185,625	698	0.0001	1.0000	99.30
17.5	18,482,009	167	0.0000	1.0000	99.30
18.5	18,481,842	3,289	0.0002	0.9998	99.30
19.5	11,765,425	0	0.0000	1.0000	99.28
20.5	11,733,967	20,086	0.0017	0.9983	99.28
21.5	11,694,903	26,030	0.0022	0.9978	99.11
22.5	11,668,873	33,578	0.0029	0.9971	98.89
23.5	11,128,134	12,826	0.0012	0.9989	98.61
24.5	10,408,291	0	0.0000	1.0000	98.50
25.5	10,408,291	0	0.0000	1.0000	98.50
26.5	10,392,941	0	0.0000	1.0000	98.50
27.5	10,392,941	271,167	0.0261	0.9739	98.50
28.5	10,056,706	0	0.0000	1.0000	95.93
29.5	10,056,706	85,735	0.0085	0.9915	95.93
30.5	9,883,188	50	0.0000	1.0000	95.11
31.5	9,883,138	1,528	0.0002	0.9999	95.11
32.5	9,881,610	764	0.0001	0.9999	95.10
33.5	9,880,846	2,026	0.0002	0.9998	95.09
34.5	9,878,820	0	0.0000	1.0000	95.07
35.5	430,634	0	0.0000	1.0000	95.07
36.5	430,634	0	0.0000	1.0000	95.07
37.5	430,634	0	0.0000	1.0000	95.07
38.5	430,634	0	0.0000	1.0000	95.07
39.5	430,634	0	0.0000	1.0000	95.07
40.5	430,634	0	0.0000	1.0000	95.07
41.5	430,634	0	0.0000	1.0000	95.07
42.5	430,634	15,405	0.0358	0.9642	95.07
43.5	415,229	0	0.0000	1.0000	91.67

FortisBC - Electricity

Account #: 332.00 - Reservoirs, dams and waterways

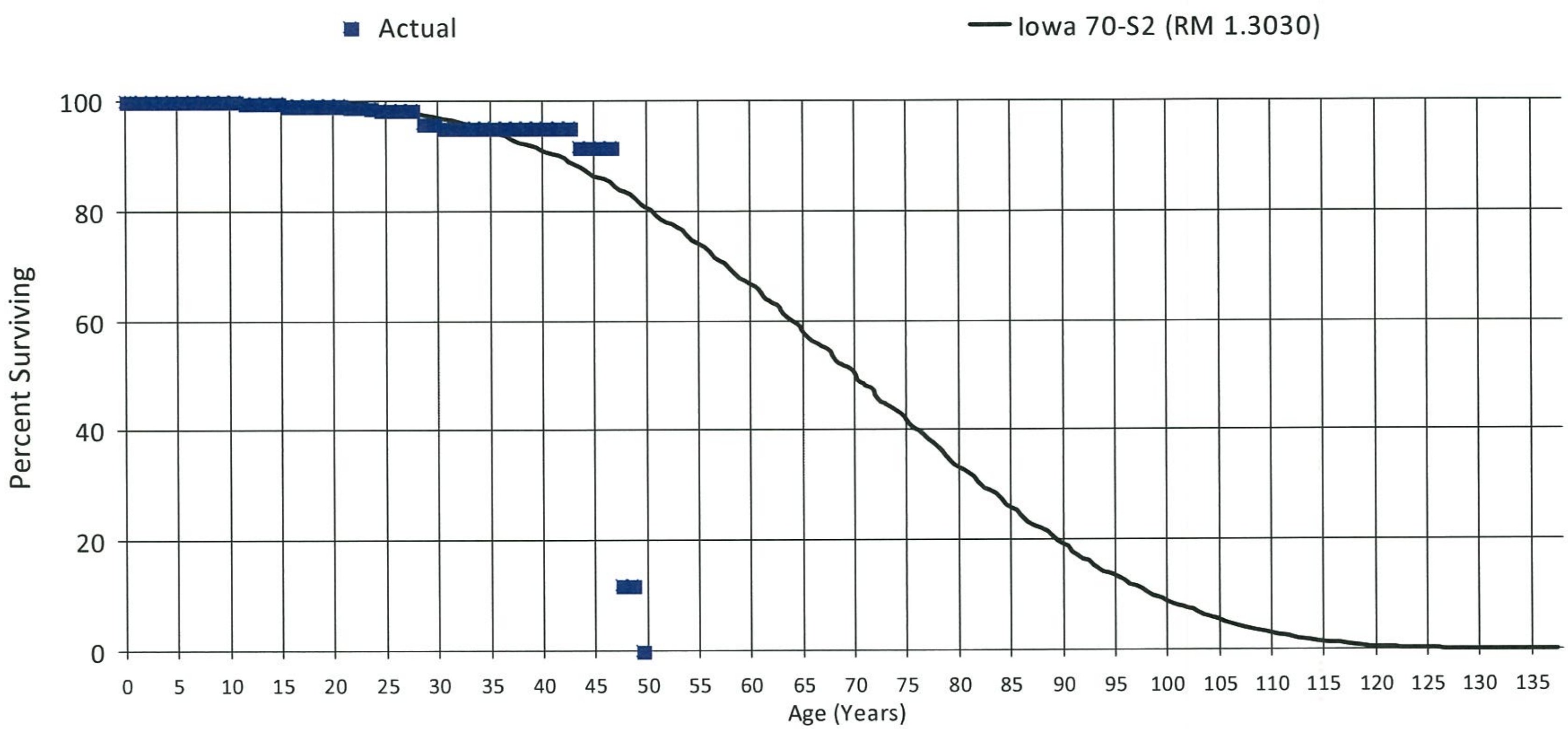
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	415,229	0	0.0000	1.0000	91.67
45.5	422,498	0	0.0000	1.0000	91.67
46.5	422,498	367,027	0.8687	0.1313	91.67
47.5	55,471	0	0.0000	1.0000	12.04
48.5	55,471	55,471	1.0000	0.0000	12.04
49.5	0	0	0.0000	0.0000	0.00

Fortis BC Inc.

Account #: 332.00 - Reservoirs, dams and waterways

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 333.00 - Water wheels, turbines and generators

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	99,138,602	2	0.0000	1.0000	100.00
0.5	98,872,314	81	0.0000	1.0000	100.00
1.5	98,632,070	0	0.0000	1.0000	100.00
2.5	98,265,589	11,780	0.0001	0.9999	100.00
3.5	97,136,799	143	0.0000	1.0000	99.99
4.5	96,910,102	54,623	0.0006	0.9994	99.99
5.5	95,510,725	0	0.0000	1.0000	99.93
6.5	74,846,204	442	0.0000	1.0000	99.93
7.5	62,518,290	919	0.0000	1.0000	99.93
8.5	54,261,328	13,082	0.0002	0.9998	99.93
9.5	55,075,556	357,852	0.0065	0.9935	99.91
10.5	46,911,360	0	0.0000	1.0000	99.26
11.5	36,773,702	0	0.0000	1.0000	99.26
12.5	36,547,056	0	0.0000	1.0000	99.26
13.5	22,736,964	3,850	0.0002	0.9998	99.26
14.5	22,621,573	34	0.0000	1.0000	99.24
15.5	22,453,596	200	0.0000	1.0000	99.24
16.5	20,775,886	169,288	0.0082	0.9919	99.24
17.5	11,622,606	1,844	0.0002	0.9998	98.43
18.5	11,445,179	370,968	0.0324	0.9676	98.41
19.5	10,510,266	0	0.0000	1.0000	95.22
20.5	10,267,795	11,543	0.0011	0.9989	95.22
21.5	9,646,468	0	0.0000	1.0000	95.11
22.5	9,382,965	0	0.0000	1.0000	95.11
23.5	9,180,618	4,535	0.0005	0.9995	95.11
24.5	9,101,084	0	0.0000	1.0000	95.06
25.5	9,024,321	8,624	0.0010	0.9990	95.06
26.5	8,751,020	26,293	0.0030	0.9970	94.97
27.5	8,654,529	0	0.0000	1.0000	94.69
28.5	8,529,689	0	0.0000	1.0000	94.69
29.5	8,509,356	0	0.0000	1.0000	94.69
30.5	8,486,117	0	0.0000	1.0000	94.69
31.5	8,344,444	166,278	0.0199	0.9801	94.69
32.5	8,153,904	0	0.0000	1.0000	92.80
33.5	8,077,507	0	0.0000	1.0000	92.80
34.5	8,077,481	100,970	0.0125	0.9875	92.80
35.5	1,778,626	0	0.0000	1.0000	91.64
36.5	1,778,626	0	0.0000	1.0000	91.64
37.5	1,778,626	112	0.0001	0.9999	91.64
38.5	1,778,514	0	0.0000	1.0000	91.63
39.5	1,778,514	0	0.0000	1.0000	91.63
40.5	1,773,062	0	0.0000	1.0000	91.63
41.5	1,773,062	0	0.0000	1.0000	91.63
42.5	1,773,062	0	0.0000	1.0000	91.63
43.5	1,773,062	0	0.0000	1.0000	91.63

FortisBC - Electricity

Account #: 333.00 - Water wheels, turbines and generators

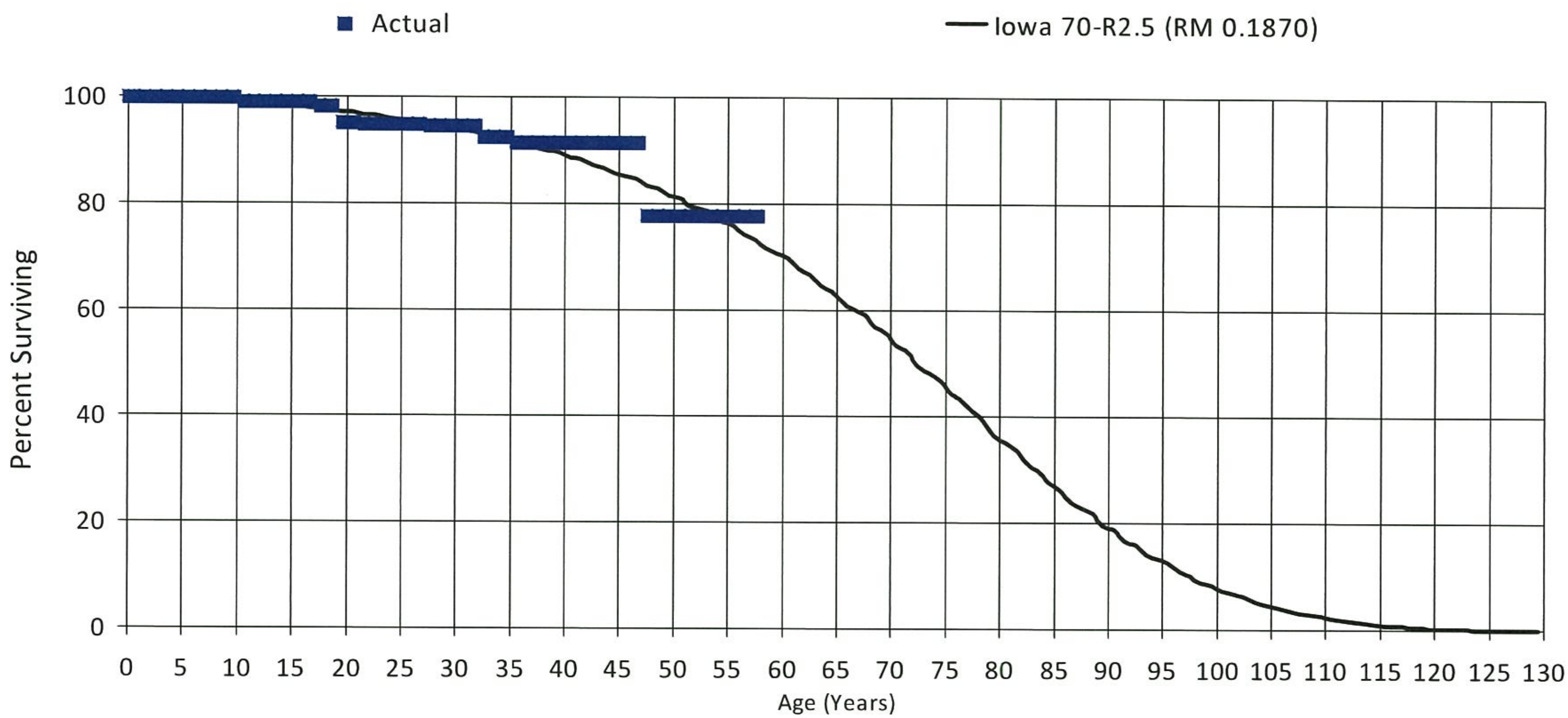
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	1,773,062	0	0.0000	1.0000	91.63
45.5	1,773,062	0	0.0000	1.0000	91.63
46.5	1,772,742	266,032	0.1501	0.8499	91.63
47.5	1,506,710	0	0.0000	1.0000	77.88
48.5	1,506,414	0	0.0000	1.0000	77.88
49.5	1,506,414	0	0.0000	1.0000	77.88
50.5	1,506,414	0	0.0000	1.0000	77.88
51.5	1,506,414	0	0.0000	1.0000	77.88
52.5	1,506,148	0	0.0000	1.0000	77.88
53.5	671,949	0	0.0000	1.0000	77.88
54.5	10,021	0	0.0000	1.0000	77.88
55.5	10,021	0	0.0000	1.0000	77.88
56.5	10,021	0	0.0000	1.0000	77.88
57.5	0	0	0.0000	0.0000	77.88

FortisBC - Electricity

Account #: 333.00 - Water wheels, turbines and generators

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1960 - 2017



FortisBC - Electricity

Account #: 334.00 - Accessory electrical equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	47,378,145	8	0.0000	1.0000	100.00
0.5	46,956,215	0	0.0000	1.0000	100.00
1.5	46,839,447	11,938	0.0003	0.9998	100.00
2.5	46,276,632	6,685	0.0001	0.9999	99.98
3.5	45,379,339	1	0.0000	1.0000	99.97
4.5	44,837,533	0	0.0000	1.0000	99.97
5.5	41,363,824	12,203	0.0003	0.9997	99.97
6.5	34,702,866	6	0.0000	1.0000	99.94
7.5	28,883,559	16,472	0.0006	0.9994	99.94
8.5	23,984,019	102,496	0.0043	0.9957	99.88
9.5	23,353,979	444,870	0.0191	0.9810	99.45
10.5	20,136,564	611,492	0.0304	0.9696	97.56
11.5	17,424,262	65,309	0.0038	0.9963	94.60
12.5	17,253,998	133,290	0.0077	0.9923	94.25
13.5	11,861,582	658,675	0.0555	0.9445	93.52
14.5	11,006,583	276,096	0.0251	0.9749	88.33
15.5	10,268,284	94,810	0.0092	0.9908	86.11
16.5	6,842,594	76,932	0.0112	0.9888	85.32
17.5	5,515,632	33,268	0.0060	0.9940	84.36
18.5	5,445,597	5,911	0.0011	0.9989	83.85
19.5	5,093,991	206,860	0.0406	0.9594	83.76
20.5	4,856,318	7,707	0.0016	0.9984	80.36
21.5	4,648,099	147,574	0.0318	0.9683	80.23
22.5	4,500,525	126,619	0.0281	0.9719	77.68
23.5	4,373,673	0	0.0000	1.0000	75.49
24.5	4,297,724	0	0.0000	1.0000	75.49
25.5	4,249,798	0	0.0000	1.0000	75.49
26.5	4,115,343	11,492	0.0028	0.9972	75.49
27.5	4,069,600	7,386	0.0018	0.9982	75.28
28.5	4,007,236	0	0.0000	1.0000	75.14
29.5	4,004,046	241,006	0.0602	0.9398	75.14
30.5	3,763,040	0	0.0000	1.0000	70.62
31.5	3,666,050	4,594	0.0013	0.9988	70.62
32.5	3,661,456	0	0.0000	1.0000	70.53
33.5	3,620,164	0	0.0000	1.0000	70.53
34.5	3,620,164	5,466	0.0015	0.9985	70.53
35.5	3,614,697	0	0.0000	1.0000	70.42
36.5	3,614,697	0	0.0000	1.0000	70.42
37.5	3,614,697	0	0.0000	1.0000	70.42
38.5	3,612,373	0	0.0000	1.0000	70.42
39.5	3,599,863	21,593	0.0060	0.9940	70.42
40.5	3,574,072	0	0.0000	1.0000	70.00
41.5	3,563,982	0	0.0000	1.0000	70.00
42.5	3,563,740	56,212	0.0158	0.9842	70.00
43.5	3,501,364	130,039	0.0371	0.9629	68.90

FortisBC - Electricity

Account #: 334.00 - Accessory electrical equipment

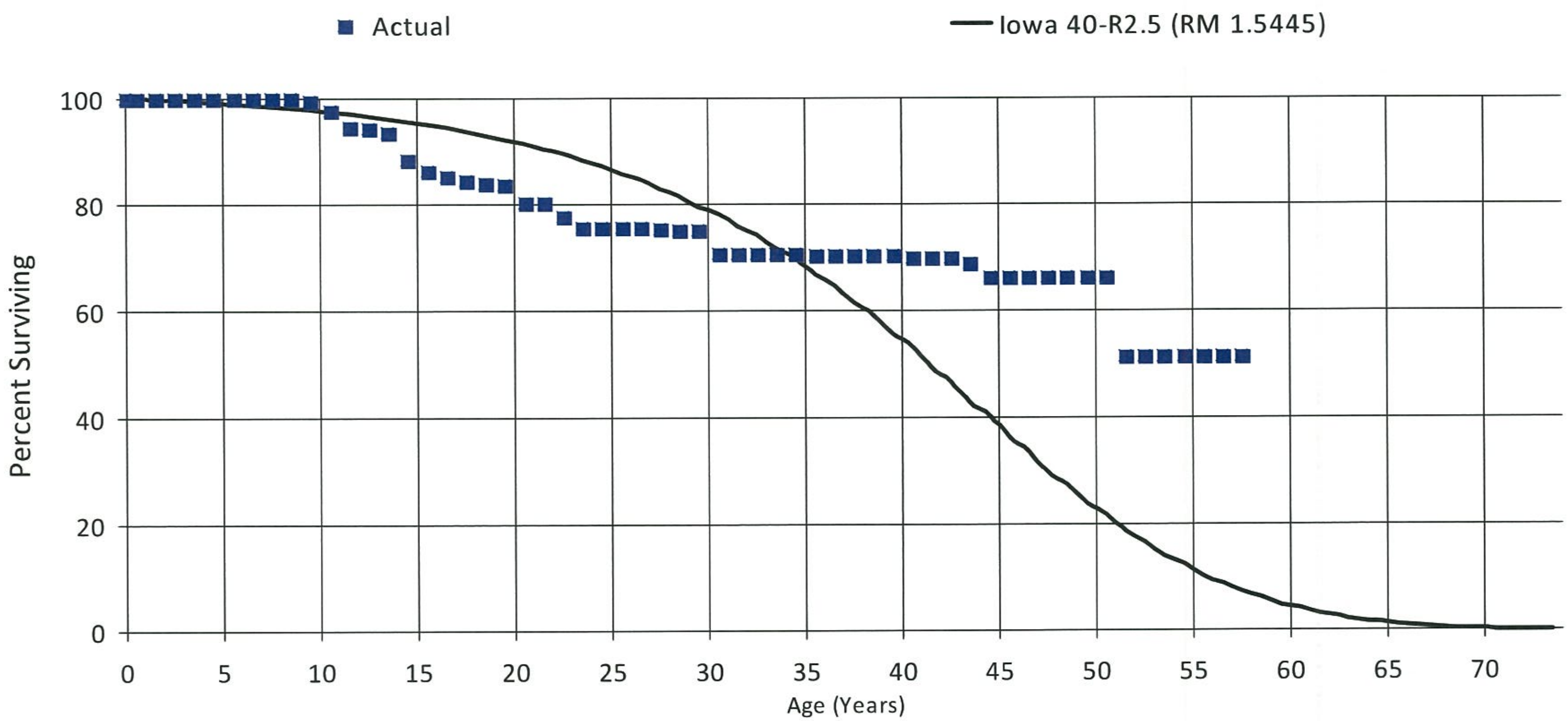
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	3,368,281	0	0.0000	1.0000	66.34
45.5	3,368,281	0	0.0000	1.0000	66.34
46.5	3,202,240	4,140	0.0013	0.9987	66.34
47.5	3,198,101	0	0.0000	1.0000	66.25
48.5	3,193,569	0	0.0000	1.0000	66.25
49.5	3,190,419	0	0.0000	1.0000	66.25
50.5	3,190,419	717,072	0.2248	0.7752	66.25
51.5	2,472,413	0	0.0000	1.0000	51.36
52.5	2,472,413	0	0.0000	1.0000	51.36
53.5	2,468,037	0	0.0000	1.0000	51.36
54.5	2,432,028	0	0.0000	1.0000	51.36
55.5	2,432,028	2,232	0.0009	0.9991	51.36
56.5	2,429,796	603	0.0003	0.9998	51.31
57.5	0	0	0.0000	0.0000	51.30

FortisBC - Electricity

Account #: 334.00 - Accessory electrical equipment

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1950 - 2017



FortisBC - Electricity

Account #: 335.00 - Other power plant equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	47,019,814	272	0.0000	1.0000	100.00
0.5	46,557,519	95,862	0.0021	0.9979	100.00
1.5	46,440,685	0	0.0000	1.0000	99.79
2.5	46,105,224	2,565	0.0001	0.9999	99.79
3.5	44,870,675	81,442	0.0018	0.9982	99.78
4.5	44,663,130	36,311	0.0008	0.9992	99.60
5.5	43,122,959	2,919	0.0001	0.9999	99.52
6.5	42,860,826	2,315	0.0001	1.0000	99.51
7.5	42,102,582	680	0.0000	1.0000	99.51
8.5	39,793,464	3,046	0.0001	0.9999	99.51
9.5	39,417,128	9,262	0.0002	0.9998	99.50
10.5	38,723,711	0	0.0000	1.0000	99.48
11.5	37,946,100	60,396	0.0016	0.9984	99.48
12.5	36,963,594	1,580	0.0000	1.0000	99.32
13.5	26,558,674	0	0.0000	1.0000	99.32
14.5	8,320,066	0	0.0000	1.0000	99.32
15.5	7,824,956	25,182	0.0032	0.9968	99.32
16.5	7,799,774	0	0.0000	1.0000	99.00
17.5	7,799,774	22,758	0.0029	0.9971	99.00
18.5	7,777,017	68,021	0.0088	0.9913	98.71
19.5	5,521,886	33,312	0.0060	0.9940	97.85
20.5	4,905,583	5,827	0.0012	0.9988	97.26
21.5	4,403,693	7,292	0.0017	0.9983	97.14
22.5	4,136,008	0	0.0000	1.0000	96.98
23.5	3,901,225	8,048	0.0021	0.9979	96.98
24.5	3,694,876	38,524	0.0104	0.9896	96.78
25.5	3,615,412	55,010	0.0152	0.9848	95.77
26.5	3,392,927	19,333	0.0057	0.9943	94.31
27.5	2,990,002	45,281	0.0151	0.9849	93.77
28.5	2,795,373	13,370	0.0048	0.9952	92.35
29.5	2,633,230	48,223	0.0183	0.9817	91.91
30.5	2,434,113	0	0.0000	1.0000	90.23
31.5	2,131,013	0	0.0000	1.0000	90.23
32.5	2,047,668	16,256	0.0079	0.9921	90.23
33.5	1,970,246	0	0.0000	1.0000	89.51
34.5	1,970,246	0	0.0000	1.0000	89.51
35.5	1,661,190	0	0.0000	1.0000	89.51
36.5	1,661,190	0	0.0000	1.0000	89.51
37.5	1,661,190	6,310	0.0038	0.9962	89.51
38.5	1,654,875	0	0.0000	1.0000	89.17
39.5	1,634,040	0	0.0000	1.0000	89.17
40.5	1,613,010	0	0.0000	1.0000	89.17
41.5	1,599,976	0	0.0000	1.0000	89.17
42.5	1,598,416	6,006	0.0038	0.9962	89.17
43.5	1,591,490	0	0.0000	1.0000	88.83

FortisBC - Electricity

Account #: 335.00 - Other power plant equipment

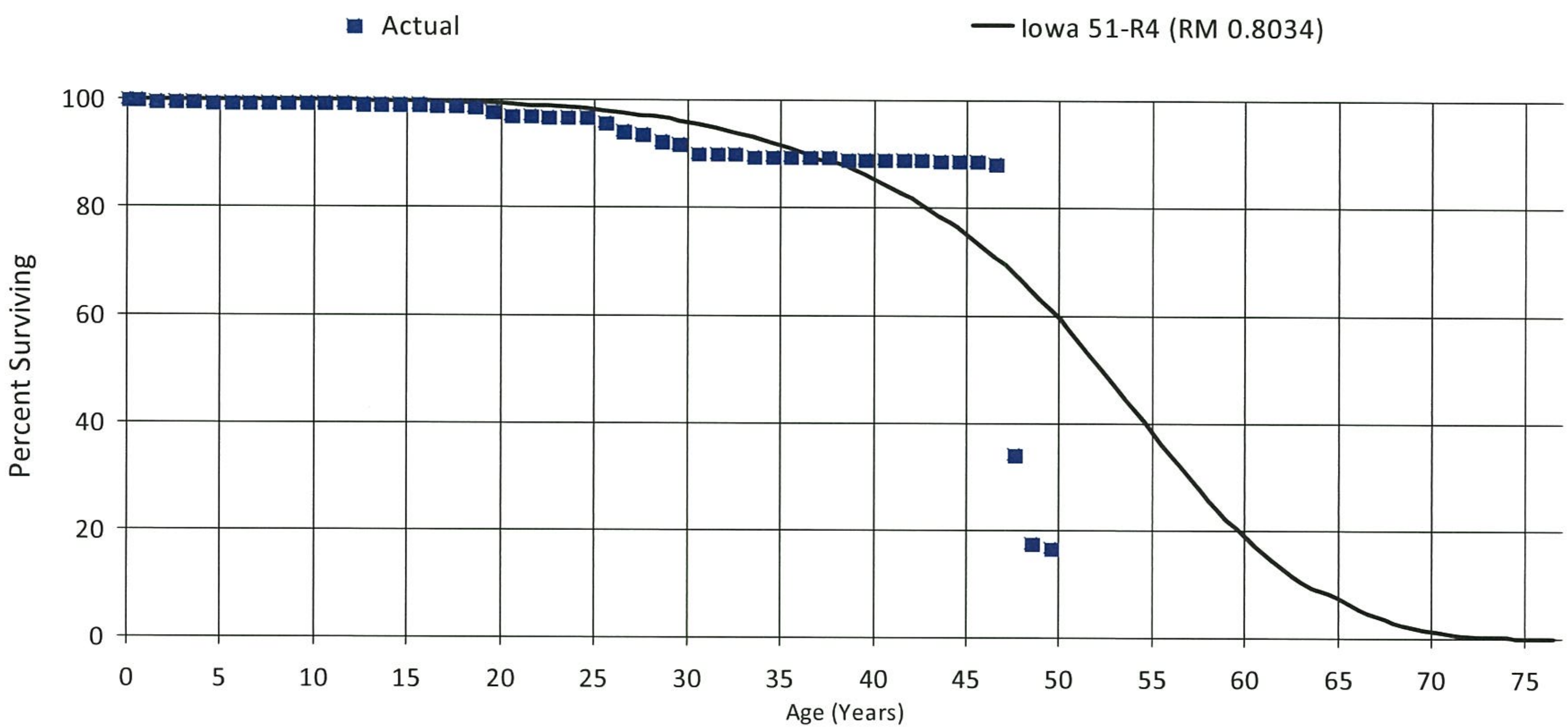
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	1,591,490	0	0.0000	1.0000	88.83
45.5	1,591,490	7,418	0.0047	0.9953	88.83
46.5	1,584,072	970,828	0.6129	0.3871	88.42
47.5	613,244	297,278	0.4848	0.5152	34.23
48.5	315,965	15,472	0.0490	0.9510	17.64
49.5	300,493	0	0.0000	1.0000	16.78

FortisBC - Electricity

Account #: 335.00 - Other power plant equipment

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1957 - 2017



FortisBC - Electricity

Account #: 336.00 - Roads, railroads and bridges

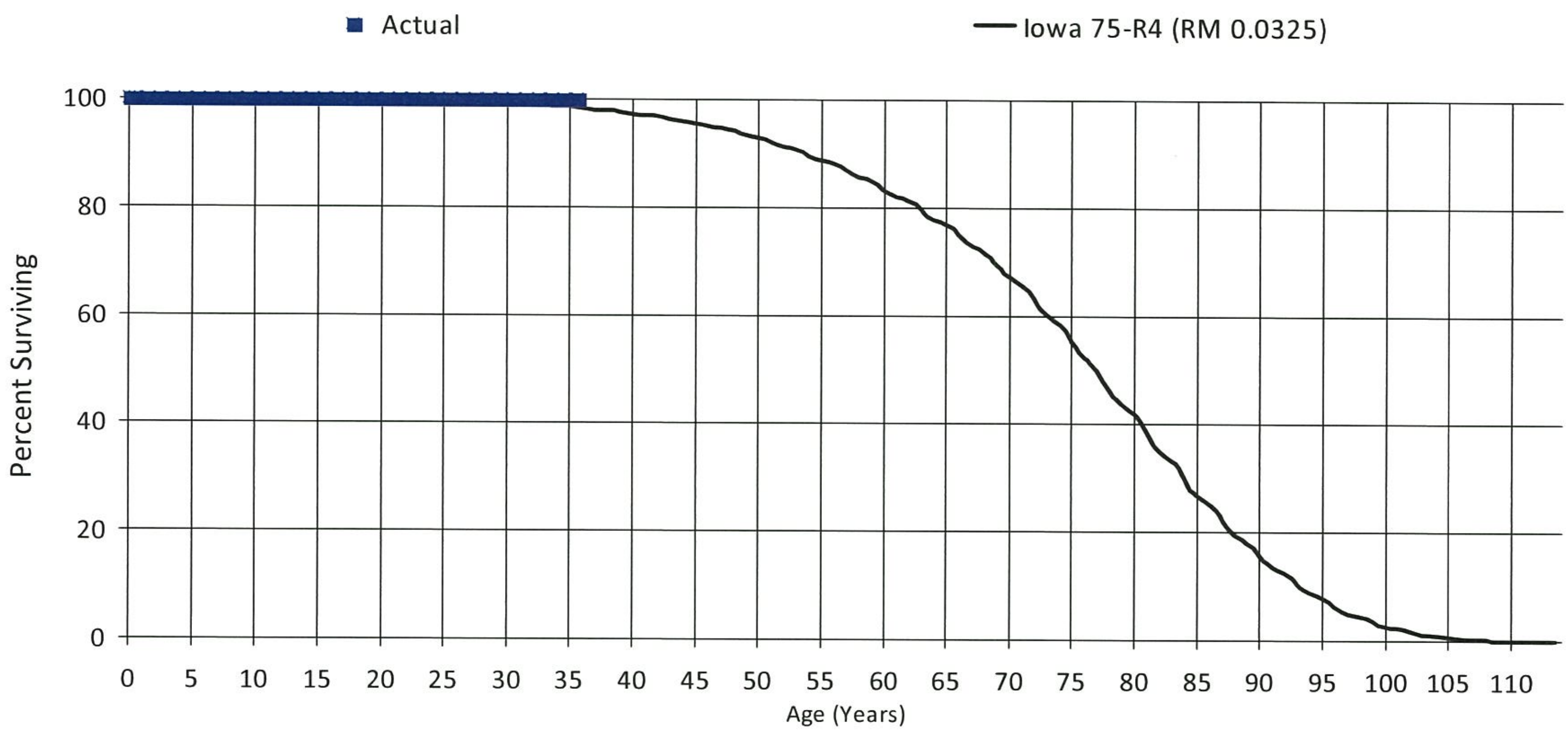
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,287,434	0	0.0000	1.0000	100.00
0.5	1,287,434	0	0.0000	1.0000	100.00
1.5	1,287,434	0	0.0000	1.0000	100.00
2.5	1,287,434	0	0.0000	1.0000	100.00
3.5	1,287,434	0	0.0000	1.0000	100.00
4.5	1,287,434	0	0.0000	1.0000	100.00
5.5	1,287,434	0	0.0000	1.0000	100.00
6.5	1,287,434	0	0.0000	1.0000	100.00
7.5	1,287,434	0	0.0000	1.0000	100.00
8.5	1,287,434	0	0.0000	1.0000	100.00
9.5	1,053,045	0	0.0000	1.0000	100.00
10.5	1,053,045	0	0.0000	1.0000	100.00
11.5	1,046,226	0	0.0000	1.0000	100.00
12.5	1,046,226	0	0.0000	1.0000	100.00
13.5	1,045,307	0	0.0000	1.0000	100.00
14.5	1,043,069	0	0.0000	1.0000	100.00
15.5	1,043,069	0	0.0000	1.0000	100.00
16.5	1,626,010	0	0.0000	1.0000	100.00
17.5	1,626,010	0	0.0000	1.0000	100.00
18.5	895,359	0	0.0000	1.0000	100.00
19.5	895,359	0	0.0000	1.0000	100.00
20.5	895,359	0	0.0000	1.0000	100.00
21.5	895,359	0	0.0000	1.0000	100.00
22.5	895,359	0	0.0000	1.0000	100.00
23.5	895,359	0	0.0000	1.0000	100.00
24.5	895,359	0	0.0000	1.0000	100.00
25.5	794,709	0	0.0000	1.0000	100.00
26.5	783,776	0	0.0000	1.0000	100.00
27.5	659,334	0	0.0000	1.0000	100.00
28.5	625,867	0	0.0000	1.0000	100.00
29.5	613,505	0	0.0000	1.0000	100.00
30.5	613,505	0	0.0000	1.0000	100.00
31.5	613,505	0	0.0000	1.0000	100.00
32.5	613,505	0	0.0000	1.0000	100.00
33.5	589,100	0	0.0000	1.0000	100.00
34.5	589,100	0	0.0000	1.0000	100.00
35.5	0	0	0.0000	0.0000	100.00

FortisBC - Electricity

Account #: 336.00 - Roads, railroads and bridges

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1982 - 2017



FortisBC - Electricity

Account #: 350.20 - Transmission Plant - Surface and Mineral

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	8,173,036	0	0.0000	1.0000	100.00
0.5	8,124,049	0	0.0000	1.0000	100.00
1.5	8,089,300	0	0.0000	1.0000	100.00
2.5	8,046,804	0	0.0000	1.0000	100.00
3.5	7,993,273	0	0.0000	1.0000	100.00
4.5	7,980,696	0	0.0000	1.0000	100.00
5.5	7,936,064	0	0.0000	1.0000	100.00
6.5	7,849,780	0	0.0000	1.0000	100.00
7.5	7,412,230	0	0.0000	1.0000	100.00
8.5	6,961,797	0	0.0000	1.0000	100.00
9.5	5,847,236	0	0.0000	1.0000	100.00
10.5	4,363,677	0	0.0000	1.0000	100.00
11.5	4,292,061	0	0.0000	1.0000	100.00
12.5	3,202,451	0	0.0000	1.0000	100.00
13.5	3,032,990	0	0.0000	1.0000	100.00
14.5	2,743,465	0	0.0000	1.0000	100.00
15.5	2,743,465	0	0.0000	1.0000	100.00
16.5	2,623,386	0	0.0000	1.0000	100.00
17.5	2,398,250	0	0.0000	1.0000	100.00
18.5	2,320,120	0	0.0000	1.0000	100.00
19.5	2,107,190	0	0.0000	1.0000	100.00
20.5	2,032,945	0	0.0000	1.0000	100.00
21.5	1,716,420	0	0.0000	1.0000	100.00
22.5	1,665,506	0	0.0000	1.0000	100.00
23.5	1,355,675	0	0.0000	1.0000	100.00
24.5	1,294,168	0	0.0000	1.0000	100.00
25.5	1,244,067	0	0.0000	1.0000	100.00
26.5	1,178,569	0	0.0000	1.0000	100.00
27.5	1,119,640	0	0.0000	1.0000	100.00
28.5	1,070,424	0	0.0000	1.0000	100.00
29.5	973,976	0	0.0000	1.0000	100.00
30.5	893,749	0	0.0000	1.0000	100.00
31.5	762,809	0	0.0000	1.0000	100.00
32.5	658,417	0	0.0000	1.0000	100.00
33.5	520,434	0	0.0000	1.0000	100.00
34.5	470,331	0	0.0000	1.0000	100.00
35.5	428,696	0	0.0000	1.0000	100.00
36.5	408,973	0	0.0000	1.0000	100.00
37.5	357,588	0	0.0000	1.0000	100.00
38.5	331,094	0	0.0000	1.0000	100.00
39.5	320,262	0	0.0000	1.0000	100.00
40.5	310,199	0	0.0000	1.0000	100.00
41.5	224,331	0	0.0000	1.0000	100.00
42.5	216,135	0	0.0000	1.0000	100.00
43.5	211,637	0	0.0000	1.0000	100.00

FortisBC - Electricity

Account #: 350.20 - Transmission Plant - Surface and Mineral

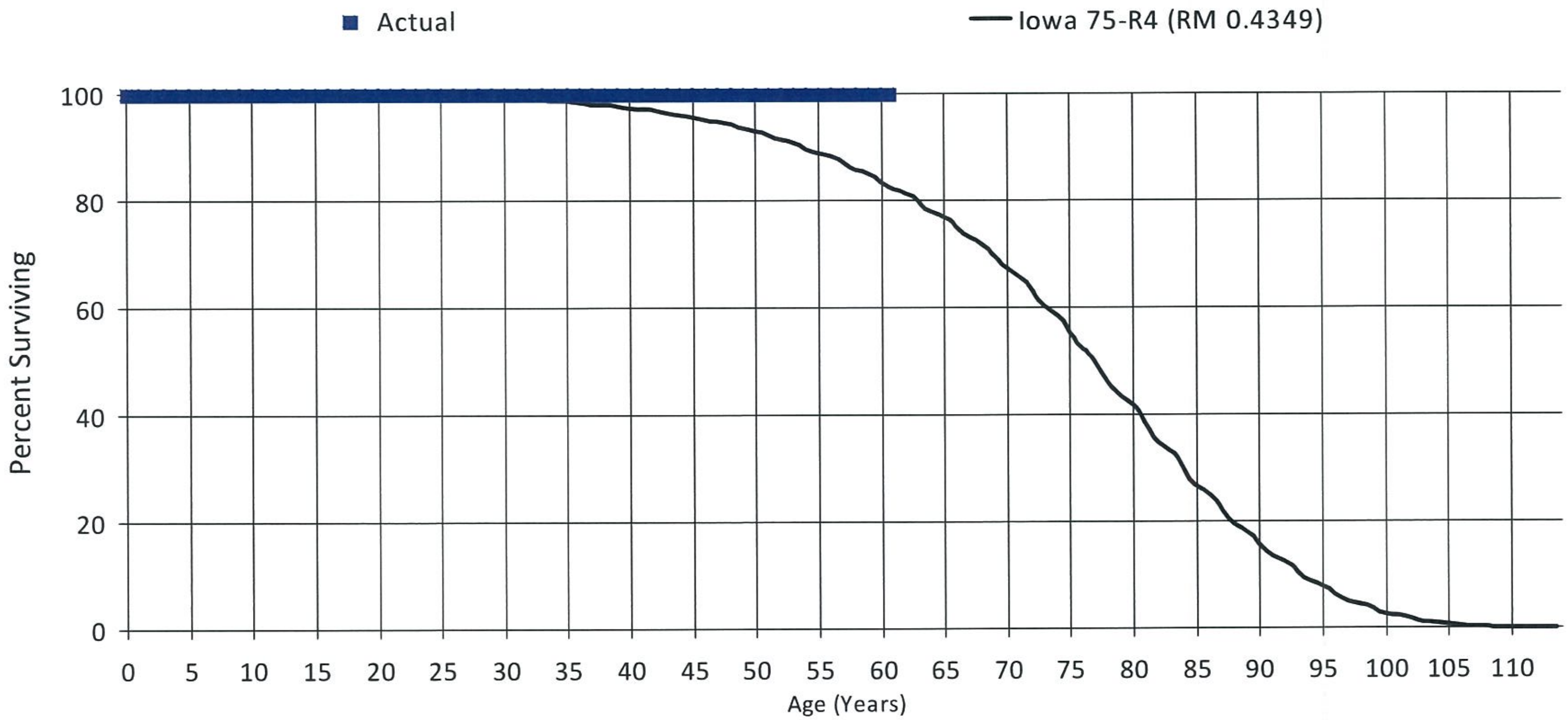
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	210,804	0	0.0000	1.0000	100.00
45.5	210,325	0	0.0000	1.0000	100.00
46.5	208,682	0	0.0000	1.0000	100.00
47.5	207,813	0	0.0000	1.0000	100.00
48.5	206,616	0	0.0000	1.0000	100.00
49.5	206,020	0	0.0000	1.0000	100.00
50.5	203,661	0	0.0000	1.0000	100.00
51.5	199,710	0	0.0000	1.0000	100.00
52.5	180,436	0	0.0000	1.0000	100.00
53.5	163,443	0	0.0000	1.0000	100.00
54.5	132,182	0	0.0000	1.0000	100.00
55.5	112,026	0	0.0000	1.0000	100.00
56.5	109,176	0	0.0000	1.0000	100.00
57.5	108,593	0	0.0000	1.0000	100.00
58.5	105,830	0	0.0000	1.0000	100.00
59.5	71,278	0	0.0000	1.0000	100.00
60.5	0	0	0.0000	0.0000	100.00

FortisBC - Electricity

Account #: 350.20 - Transmission Plant - Surface and Mineral

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 353.00 - Transmission Plant - Substation Equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	235,615,821	61,913	0.0003	0.9997	100.00
0.5	232,100,717	12,672	0.0001	1.0000	99.97
1.5	230,414,621	889	0.0000	1.0000	99.97
2.5	228,680,217	1,895	0.0000	1.0000	99.97
3.5	218,853,032	3,359	0.0000	1.0000	99.97
4.5	217,183,652	311,171	0.0014	0.9986	99.97
5.5	210,569,322	60,553	0.0003	0.9997	99.83
6.5	169,242,735	22,102	0.0001	0.9999	99.80
7.5	159,074,999	4,635	0.0000	1.0000	99.79
8.5	156,220,902	11,949	0.0001	0.9999	99.79
9.5	153,988,033	6,909	0.0000	1.0000	99.78
10.5	144,408,334	162,000	0.0011	0.9989	99.78
11.5	125,234,447	12,448	0.0001	0.9999	99.67
12.5	75,123,120	42,330	0.0006	0.9994	99.66
13.5	65,347,849	13,010	0.0002	0.9998	99.60
14.5	32,497,307	6,244	0.0002	0.9998	99.58
15.5	32,447,311	22,135	0.0007	0.9993	99.56
16.5	30,944,813	93,327	0.0030	0.9970	99.49
17.5	30,239,078	0	0.0000	1.0000	99.19
18.5	29,888,878	30,539	0.0010	0.9990	99.19
19.5	29,048,652	10,705	0.0004	0.9996	99.09
20.5	28,580,541	510	0.0000	1.0000	99.05
21.5	24,873,511	251,691	0.0101	0.9899	99.05
22.5	23,204,866	150,320	0.0065	0.9935	98.05
23.5	22,366,977	0	0.0000	1.0000	97.41
24.5	20,671,996	78,454	0.0038	0.9962	97.41
25.5	20,024,332	2,403	0.0001	0.9999	97.04
26.5	19,225,037	0	0.0000	1.0000	97.03
27.5	19,002,463	54,795	0.0029	0.9971	97.03
28.5	18,713,313	7,596	0.0004	0.9996	96.75
29.5	18,659,666	32,412	0.0017	0.9983	96.71
30.5	16,051,027	75,617	0.0047	0.9953	96.54
31.5	15,475,007	99,191	0.0064	0.9936	96.09
32.5	11,555,770	10,998	0.0010	0.9991	95.47
33.5	10,727,748	92,236	0.0086	0.9914	95.38
34.5	10,553,436	166,394	0.0158	0.9842	94.56
35.5	7,667,606	320,075	0.0417	0.9583	93.07
36.5	7,331,595	17,358	0.0024	0.9976	89.19
37.5	7,145,972	0	0.0000	1.0000	88.98
38.5	5,566,192	392,505	0.0705	0.9295	88.98
39.5	3,759,990	112,909	0.0300	0.9700	82.71
40.5	2,255,684	77,092	0.0342	0.9658	80.23
41.5	2,166,574	2,588	0.0012	0.9988	77.49
42.5	2,079,393	4,738	0.0023	0.9977	77.40
43.5	2,073,184	1,267	0.0006	0.9994	77.22

FortisBC - Electricity

Account #: 353.00 - Transmission Plant - Substation Equipment

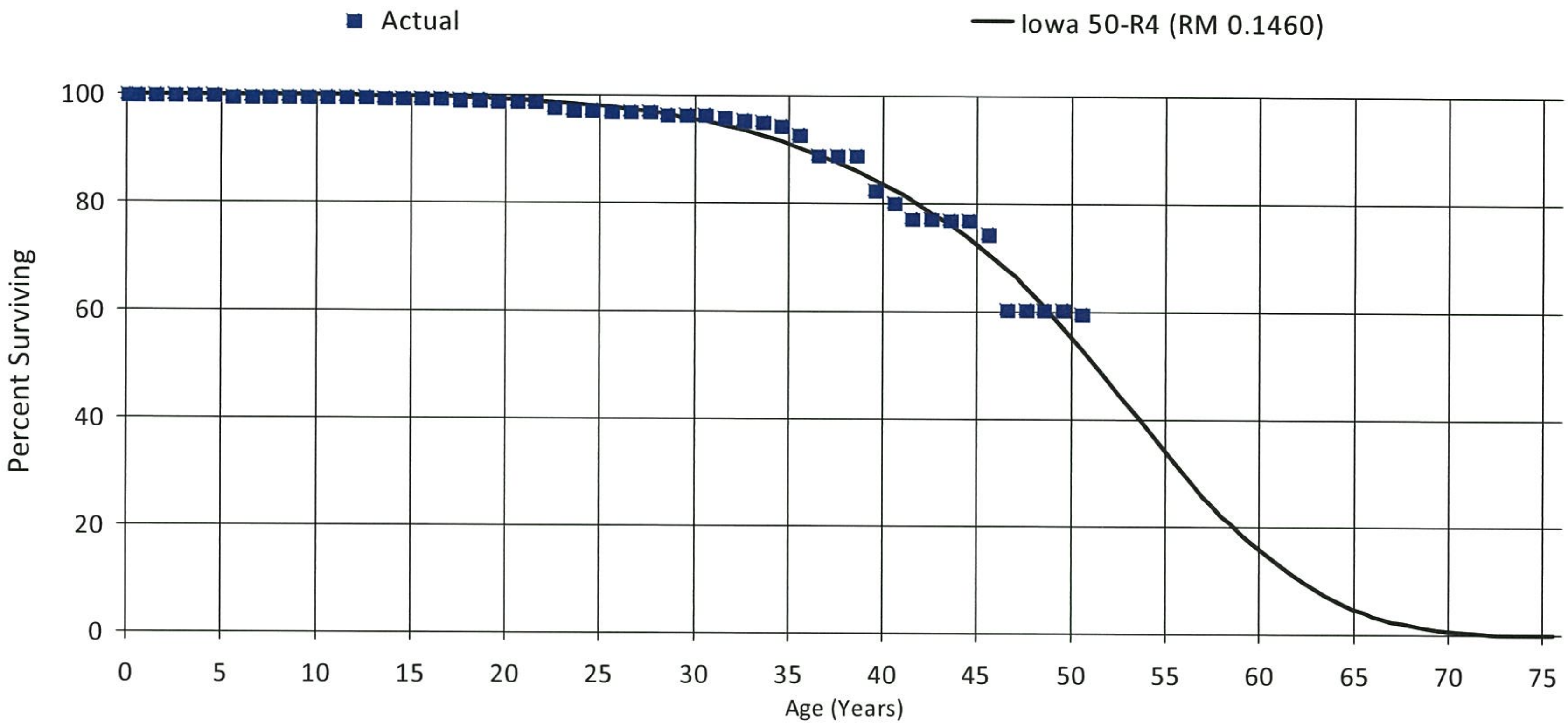
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	2,067,911	73,764	0.0357	0.9643	77.17
45.5	1,610,597	299,212	0.1858	0.8142	74.42
46.5	1,295,115	323	0.0003	0.9998	60.59
47.5	1,284,829	2,276	0.0018	0.9982	60.57
48.5	824,207	93	0.0001	0.9999	60.46
49.5	824,067	8,693	0.0106	0.9895	60.45
50.5	790,104	0	0.0000	1.0000	59.81
51.5	407,012	0	0.0000	1.0000	59.81
52.5	400,240	312,038	0.7796	0.2204	59.81
53.5	88,189	3,189	0.0362	0.9638	13.18
54.5	85,000	13,920	0.1638	0.8362	12.70
55.5	71,079	0	0.0000	1.0000	10.62
56.5	70,937	14,107	0.1989	0.8011	10.62
57.5	0	0	0.0000	0.0000	8.51

FortisBC - Electricity

Account #: 353.00 - Transmission Plant - Substation Equipment

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 355.00 - Transmission Plant - Poles, Towers and Fixtures

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	119,829,033	3,015	0.0000	1.0000	100.00
0.5	117,711,603	68,974	0.0006	0.9994	100.00
1.5	114,193,464	150,928	0.0013	0.9987	99.94
2.5	110,837,562	23,901	0.0002	0.9998	99.81
3.5	101,966,953	48,875	0.0005	0.9995	99.79
4.5	101,338,192	882,493	0.0087	0.9913	99.74
5.5	98,221,444	237,858	0.0024	0.9976	98.87
6.5	95,138,100	100,379	0.0011	0.9989	98.63
7.5	74,662,493	355,616	0.0048	0.9952	98.53
8.5	69,808,543	37,735	0.0005	0.9995	98.06
9.5	66,699,953	150,135	0.0023	0.9978	98.01
10.5	58,422,621	294,780	0.0051	0.9950	97.79
11.5	55,367,758	179,698	0.0033	0.9968	97.30
12.5	49,510,329	105,721	0.0021	0.9979	96.98
13.5	42,423,480	245,996	0.0058	0.9942	96.77
14.5	33,714,257	444,152	0.0132	0.9868	96.21
15.5	32,831,488	207,404	0.0063	0.9937	94.94
16.5	31,192,979	195,622	0.0063	0.9937	94.34
17.5	28,402,841	278,045	0.0098	0.9902	93.75
18.5	27,269,635	391,191	0.0144	0.9857	92.83
19.5	24,479,503	214,752	0.0088	0.9912	91.50
20.5	23,427,005	246,943	0.0105	0.9895	90.70
21.5	19,544,719	448,928	0.0230	0.9770	89.74
22.5	18,529,417	447,689	0.0242	0.9758	87.68
23.5	14,518,417	142,439	0.0098	0.9902	85.56
24.5	13,911,229	93,694	0.0067	0.9933	84.72
25.5	13,414,592	167,107	0.0125	0.9875	84.15
26.5	12,774,725	90,851	0.0071	0.9929	83.10
27.5	12,160,995	145,083	0.0119	0.9881	82.51
28.5	11,685,697	94,634	0.0081	0.9919	81.53
29.5	10,806,286	86,245	0.0080	0.9920	80.87
30.5	10,224,768	279,317	0.0273	0.9727	80.22
31.5	8,540,589	106,858	0.0125	0.9875	78.03
32.5	7,441,642	90,978	0.0122	0.9878	77.05
33.5	5,949,629	5,236	0.0009	0.9991	76.11
34.5	5,373,850	65,836	0.0123	0.9878	76.04
35.5	4,884,523	165,960	0.0340	0.9660	75.11
36.5	4,551,786	1,470	0.0003	0.9997	72.56
37.5	3,987,184	24,270	0.0061	0.9939	72.54
38.5	3,873,854	79,533	0.0205	0.9795	72.10
39.5	3,698,644	88,503	0.0239	0.9761	70.62
40.5	3,556,286	1,995	0.0006	0.9994	68.93
41.5	2,582,393	136	0.0001	1.0000	68.89
42.5	2,488,466	3,560	0.0014	0.9986	68.89
43.5	2,453,510	0	0.0000	1.0000	68.79

FortisBC - Electricity

Account #: 355.00 - Transmission Plant - Poles, Towers and Fixtures

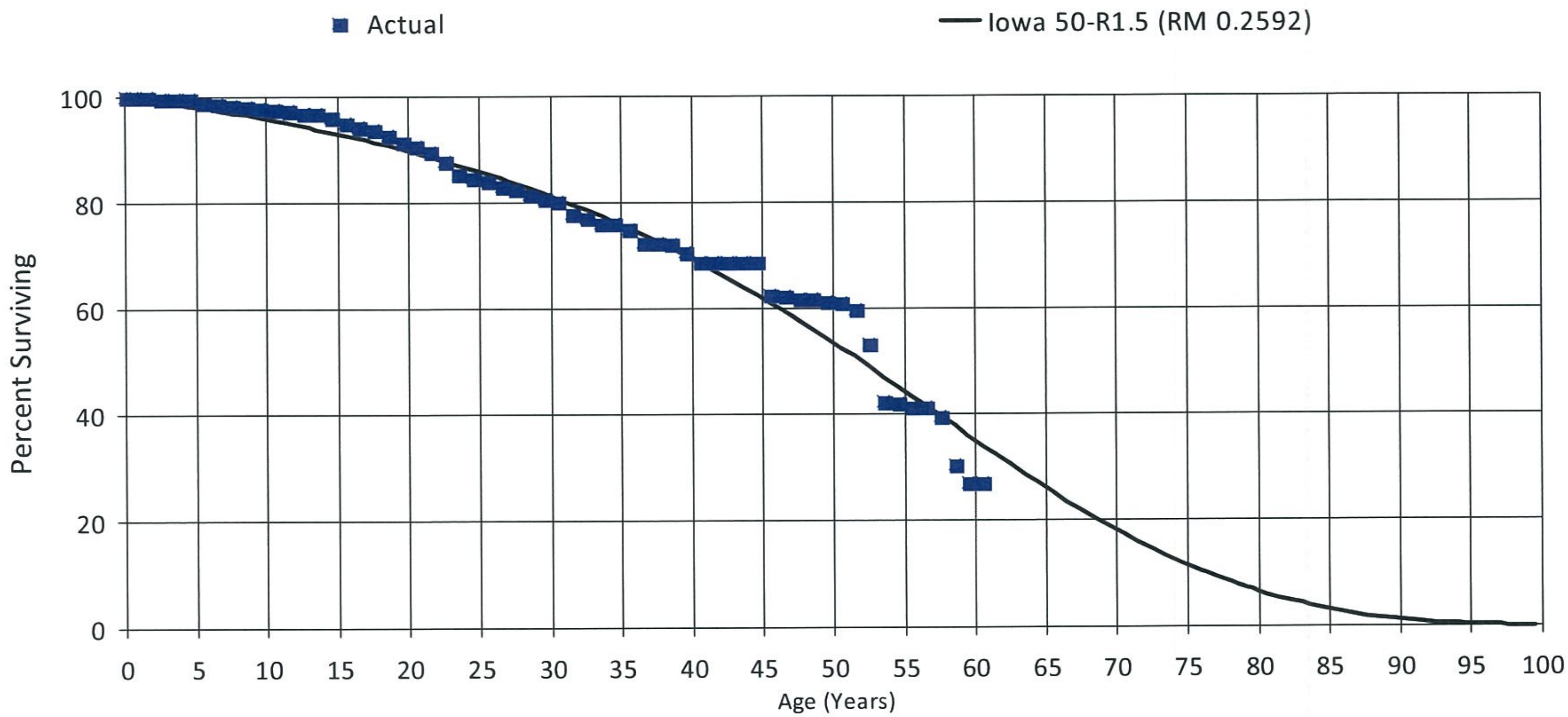
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	2,447,265	216,149	0.0883	0.9117	68.79
45.5	2,227,296	11,960	0.0054	0.9946	62.71
46.5	2,211,584	17,905	0.0081	0.9919	62.37
47.5	2,190,648	3,243	0.0015	0.9985	61.86
48.5	2,181,584	16,940	0.0078	0.9922	61.77
49.5	2,160,955	5,057	0.0023	0.9977	61.29
50.5	2,136,572	52,001	0.0243	0.9757	61.15
51.5	2,050,626	219,909	0.1072	0.8928	59.66
52.5	1,789,173	370,900	0.2073	0.7927	53.26
53.5	1,269,736	3,189	0.0025	0.9975	42.22
54.5	944,389	17,081	0.0181	0.9819	42.11
55.5	750,942	612	0.0008	0.9992	41.35
56.5	747,344	32,951	0.0441	0.9559	41.32
57.5	703,858	164,266	0.2334	0.7666	39.50
58.5	443,318	47,649	0.1075	0.8925	30.28
59.5	221,479	0	0.0000	1.0000	27.03
60.5	0	0	0.0000	0.0000	27.03

FortisBC - Electricity

Account #: 355.00 - Transmission Plant - Poles, Towers and Fixtures

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017 Experience Band - 1950 - 2017



FortisBC - Electricity

Account #: 356.00 - Transmission Plant - Overhead Conductors and Devices

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	116,674,269	333,465	0.0029	0.9971	100.00
0.5	114,226,097	65,274	0.0006	0.9994	99.71
1.5	110,680,473	13,498	0.0001	0.9999	99.65
2.5	107,255,189	124,592	0.0012	0.9988	99.64
3.5	99,519,930	15,210	0.0002	0.9999	99.52
4.5	98,525,244	643,958	0.0065	0.9935	99.51
5.5	95,645,841	176,181	0.0018	0.9982	98.86
6.5	92,671,576	48,893	0.0005	0.9995	98.68
7.5	72,247,341	412,526	0.0057	0.9943	98.63
8.5	67,100,199	77,249	0.0012	0.9989	98.07
9.5	63,955,898	677,234	0.0106	0.9894	97.96
10.5	57,710,115	126,572	0.0022	0.9978	96.92
11.5	55,029,937	94,584	0.0017	0.9983	96.71
12.5	50,721,318	122,916	0.0024	0.9976	96.54
13.5	43,374,664	107,027	0.0025	0.9975	96.31
14.5	34,798,798	126,883	0.0037	0.9964	96.07
15.5	34,212,392	241,238	0.0071	0.9930	95.72
16.5	32,510,547	169,081	0.0052	0.9948	95.05
17.5	29,678,980	233,139	0.0079	0.9921	94.56
18.5	28,492,495	359,636	0.0126	0.9874	93.82
19.5	25,579,849	38,920	0.0015	0.9985	92.64
20.5	24,670,170	381,248	0.0155	0.9846	92.50
21.5	20,508,194	674,363	0.0329	0.9671	91.07
22.5	19,219,446	407,523	0.0212	0.9788	88.08
23.5	15,122,721	107,076	0.0071	0.9929	86.21
24.5	14,505,716	53,935	0.0037	0.9963	85.60
25.5	14,021,731	160,385	0.0114	0.9886	85.28
26.5	13,369,823	88,468	0.0066	0.9934	84.30
27.5	12,743,149	46,439	0.0036	0.9964	83.74
28.5	12,356,814	370,974	0.0300	0.9700	83.44
29.5	11,179,418	82,566	0.0074	0.9926	80.94
30.5	10,544,367	35,427	0.0034	0.9966	80.34
31.5	9,065,341	268,073	0.0296	0.9704	80.07
32.5	7,687,206	74,713	0.0097	0.9903	77.70
33.5	6,169,236	4,141	0.0007	0.9993	76.94
34.5	5,569,448	53,145	0.0095	0.9905	76.89
35.5	5,080,398	57,255	0.0113	0.9887	76.16
36.5	4,851,477	24,429	0.0050	0.9950	75.30
37.5	4,237,366	99,592	0.0235	0.9765	74.92
38.5	3,889,177	240,779	0.0619	0.9381	73.16
39.5	3,571,718	55,466	0.0155	0.9845	68.63
40.5	3,460,819	5,517	0.0016	0.9984	67.56
41.5	2,448,855	2,669	0.0011	0.9989	67.45
42.5	2,348,797	10,091	0.0043	0.9957	67.38
43.5	2,306,389	11,970	0.0052	0.9948	67.09

FortisBC - Electricity

Account #: 356.00 - Transmission Plant - Overhead Conductors and Devices

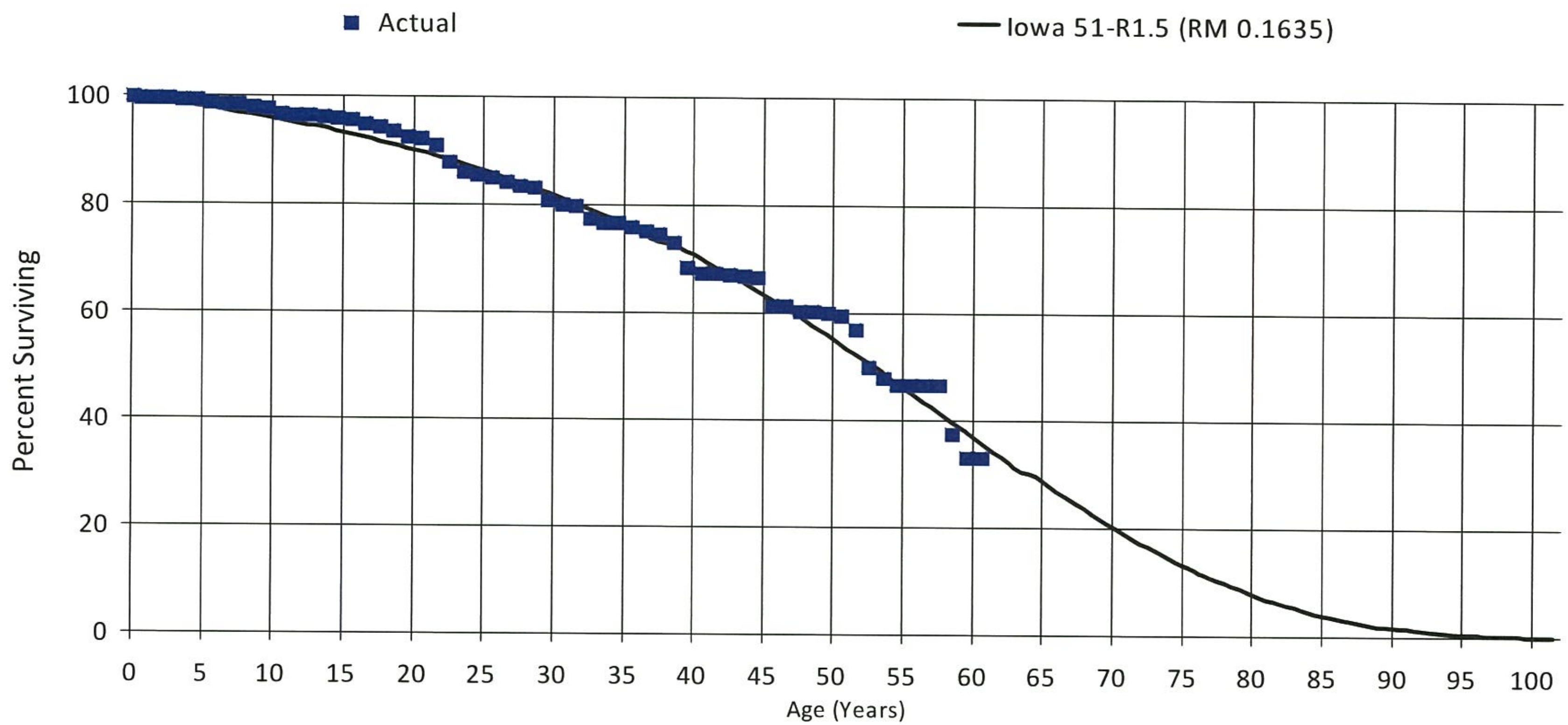
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	2,287,991	176,823	0.0773	0.9227	66.74
45.5	2,107,237	4,858	0.0023	0.9977	61.58
46.5	2,098,517	29,993	0.0143	0.9857	61.44
47.5	2,065,404	3,120	0.0015	0.9985	60.56
48.5	2,056,292	10,908	0.0053	0.9947	60.47
49.5	2,041,587	11,650	0.0057	0.9943	60.15
50.5	2,007,359	87,075	0.0434	0.9566	59.81
51.5	1,884,400	230,172	0.1222	0.8779	57.22
52.5	1,611,163	66,285	0.0411	0.9589	50.23
53.5	1,369,156	42,725	0.0312	0.9688	48.16
54.5	984,542	0	0.0000	1.0000	46.66
55.5	809,353	0	0.0000	1.0000	46.66
56.5	802,222	0	0.0000	1.0000	46.66
57.5	790,748	154,187	0.1950	0.8050	46.66
58.5	533,861	61,208	0.1147	0.8854	37.56
59.5	284,646	0	0.0000	1.0000	33.25
60.5	0	0	0.0000	0.0000	33.25

FortisBC - Electricity

Account #: 356.00 - Transmission Plant - Overhead Conductors and Devices

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017 Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 359.00 - Roads and Trails

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,230,779	34	0.0000	1.0000	100.00
0.5	1,230,745	0	0.0000	1.0000	100.00
1.5	1,230,745	5	0.0000	1.0000	100.00
2.5	1,230,740	145	0.0001	0.9999	100.00
3.5	1,230,595	59	0.0001	1.0000	99.99
4.5	1,230,536	36	0.0000	1.0000	99.99
5.5	1,230,500	256	0.0002	0.9998	99.99
6.5	1,230,245	281	0.0002	0.9998	99.97
7.5	1,229,964	239	0.0002	0.9998	99.95
8.5	925,475	36	0.0000	1.0000	99.93
9.5	925,439	4	0.0000	1.0000	99.93
10.5	925,435	20	0.0000	1.0000	99.93
11.5	925,415	786	0.0009	0.9992	99.93
12.5	867,142	5	0.0000	1.0000	99.85
13.5	466,359	16	0.0000	1.0000	99.85
14.5	262,528	4	0.0000	1.0000	99.85
15.5	262,525	10,710	0.0408	0.9592	99.85
16.5	245,347	0	0.0000	1.0000	95.78
17.5	232,613	376	0.0016	0.9984	95.78
18.5	227,732	0	0.0000	1.0000	95.62
19.5	215,645	59	0.0003	0.9997	95.62
20.5	211,365	0	0.0000	1.0000	95.59
21.5	193,354	511	0.0026	0.9974	95.59
22.5	189,948	0	0.0000	1.0000	95.34
23.5	172,335	0	0.0000	1.0000	95.34
24.5	168,838	0	0.0000	1.0000	95.34
25.5	166,589	0	0.0000	1.0000	95.34
26.5	162,865	0	0.0000	1.0000	95.34
27.5	159,515	36	0.0002	0.9998	95.34
28.5	156,681	0	0.0000	1.0000	95.32
29.5	151,199	0	0.0000	1.0000	95.32
30.5	146,613	0	0.0000	1.0000	95.32
31.5	139,169	0	0.0000	1.0000	95.32
32.5	133,235	0	0.0000	1.0000	95.32
33.5	125,391	235	0.0019	0.9981	95.32
34.5	122,162	0	0.0000	1.0000	95.14
35.5	119,795	0	0.0000	1.0000	95.14
36.5	118,674	0	0.0000	1.0000	95.14
37.5	115,753	363	0.0031	0.9969	95.14
38.5	113,884	52	0.0005	0.9995	94.84
39.5	113,217	0	0.0000	1.0000	94.80
40.5	112,645	0	0.0000	1.0000	94.80
41.5	107,763	0	0.0000	1.0000	94.80
42.5	107,297	0	0.0000	1.0000	94.80
43.5	107,042	0	0.0000	1.0000	94.80

FortisBC - Electricity

Account #: 359.00 - Roads and Trails

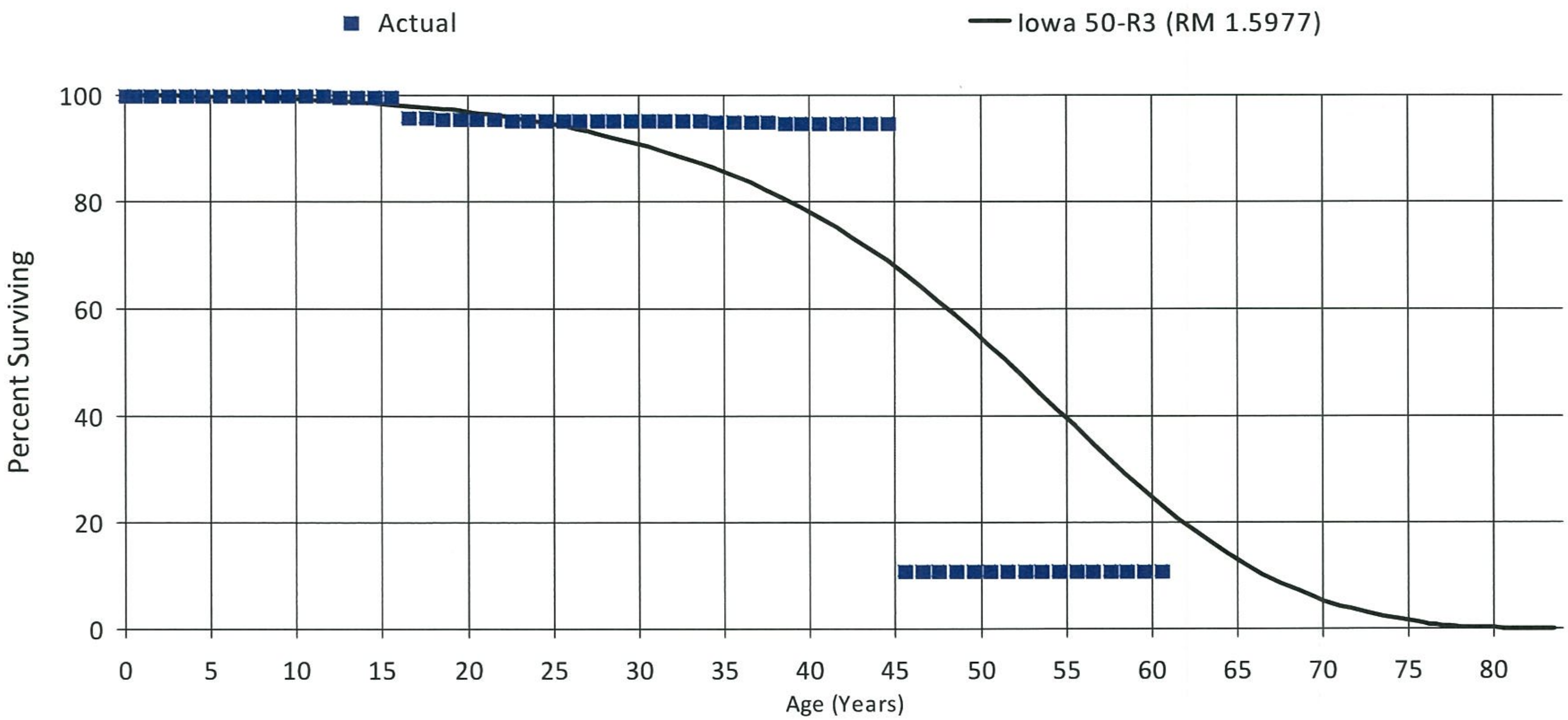
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	106,994	94,582	0.8840	0.1160	94.80
45.5	12,385	0	0.0000	1.0000	11.00
46.5	12,291	0	0.0000	1.0000	11.00
47.5	12,242	0	0.0000	1.0000	11.00
48.5	12,174	0	0.0000	1.0000	11.00
49.5	12,140	0	0.0000	1.0000	11.00
50.5	12,006	0	0.0000	1.0000	11.00
51.5	11,778	0	0.0000	1.0000	11.00
52.5	10,682	0	0.0000	1.0000	11.00
53.5	9,716	0	0.0000	1.0000	11.00
54.5	7,939	0	0.0000	1.0000	11.00
55.5	6,793	0	0.0000	1.0000	11.00
56.5	6,631	0	0.0000	1.0000	11.00
57.5	6,557	0	0.0000	1.0000	11.00
58.5	6,016	0	0.0000	1.0000	11.00
59.5	4,052	0	0.0000	1.0000	11.00
60.5	0	0	0.0000	0.0000	11.00

FortisBC - Electricity

Account #: 359.00 - Roads and Trails

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1950 - 2017



FortisBC - Electricity

Account #: 360.20 - Distribution Plant - Surface and Mineral

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	10,667,019	0	0.0000	1.0000	100.00
0.5	10,416,794	0	0.0000	1.0000	100.00
1.5	10,339,130	0	0.0000	1.0000	100.00
2.5	9,802,617	0	0.0000	1.0000	100.00
3.5	9,669,201	0	0.0000	1.0000	100.00
4.5	9,558,504	0	0.0000	1.0000	100.00
5.5	9,363,673	0	0.0000	1.0000	100.00
6.5	9,310,428	0	0.0000	1.0000	100.00
7.5	7,824,146	0	0.0000	1.0000	100.00
8.5	5,711,012	0	0.0000	1.0000	100.00
9.5	5,202,816	0	0.0000	1.0000	100.00
10.5	3,500,186	0	0.0000	1.0000	100.00
11.5	2,504,823	0	0.0000	1.0000	100.00
12.5	2,141,313	0	0.0000	1.0000	100.00
13.5	1,329,819	0	0.0000	1.0000	100.00
14.5	287,568	0	0.0000	1.0000	100.00
15.5	287,568	0	0.0000	1.0000	100.00
16.5	271,638	0	0.0000	1.0000	100.00
17.5	256,157	0	0.0000	1.0000	100.00
18.5	242,176	0	0.0000	1.0000	100.00
19.5	230,180	0	0.0000	1.0000	100.00
20.5	211,606	0	0.0000	1.0000	100.00
21.5	199,346	0	0.0000	1.0000	100.00
22.5	181,879	0	0.0000	1.0000	100.00
23.5	164,624	0	0.0000	1.0000	100.00
24.5	151,743	0	0.0000	1.0000	100.00
25.5	141,843	0	0.0000	1.0000	100.00
26.5	131,147	0	0.0000	1.0000	100.00
27.5	120,978	0	0.0000	1.0000	100.00
28.5	112,540	0	0.0000	1.0000	100.00
29.5	105,118	0	0.0000	1.0000	100.00
30.5	99,109	0	0.0000	1.0000	100.00
31.5	92,153	0	0.0000	1.0000	100.00
32.5	85,186	0	0.0000	1.0000	100.00
33.5	78,690	0	0.0000	1.0000	100.00
34.5	72,132	0	0.0000	1.0000	100.00
35.5	63,976	0	0.0000	1.0000	100.00
36.5	54,855	0	0.0000	1.0000	100.00
37.5	47,999	0	0.0000	1.0000	100.00
38.5	42,769	0	0.0000	1.0000	100.00
39.5	36,852	0	0.0000	1.0000	100.00
40.5	32,596	0	0.0000	1.0000	100.00
41.5	28,267	0	0.0000	1.0000	100.00
42.5	24,741	0	0.0000	1.0000	100.00
43.5	22,375	0	0.0000	1.0000	100.00

FortisBC - Electricity

Account #: 360.20 - Distribution Plant - Surface and Mineral

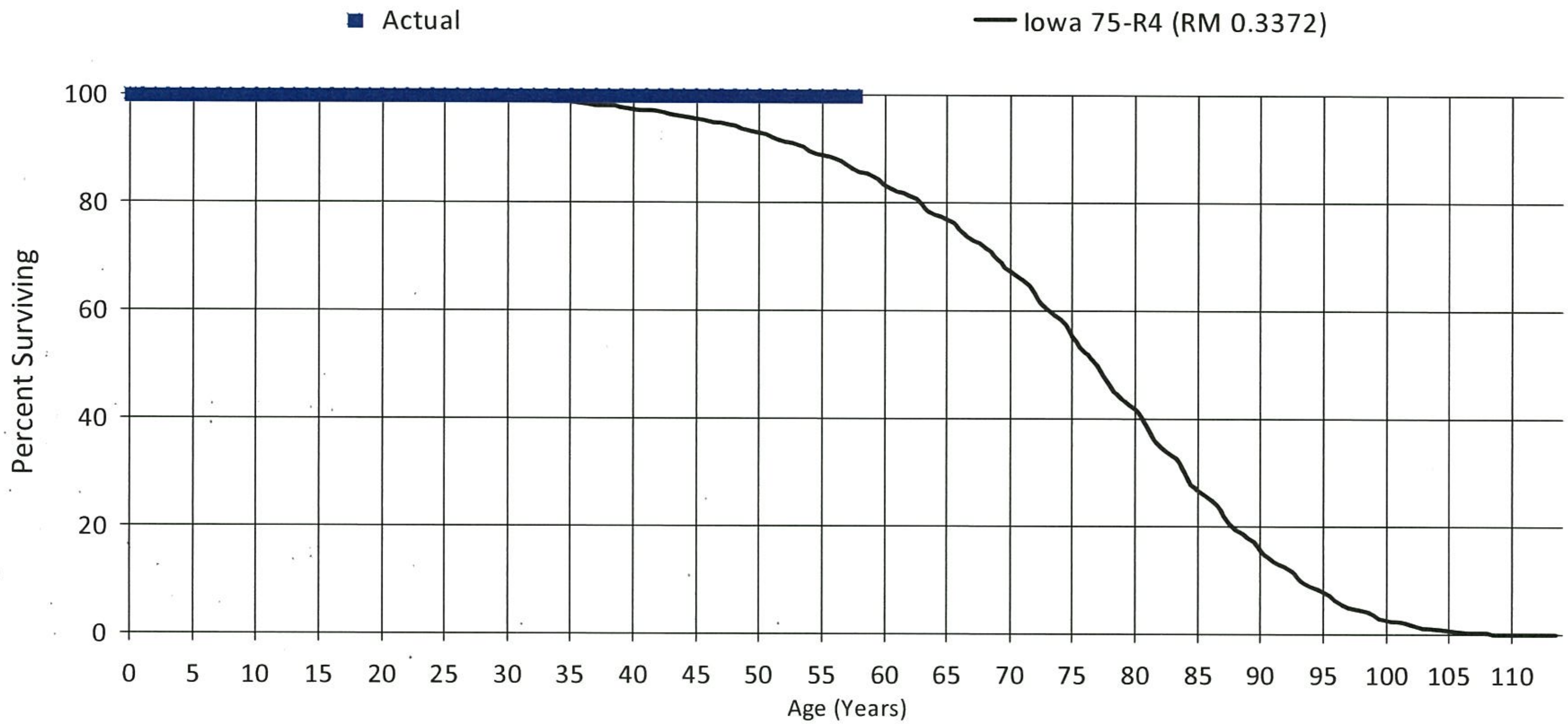
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	20,903	0	0.0000	1.0000	100.00
45.5	19,522	0	0.0000	1.0000	100.00
46.5	18,470	0	0.0000	1.0000	100.00
47.5	17,492	0	0.0000	1.0000	100.00
48.5	16,460	0	0.0000	1.0000	100.00
49.5	15,447	0	0.0000	1.0000	100.00
50.5	14,490	0	0.0000	1.0000	100.00
51.5	13,548	0	0.0000	1.0000	100.00
52.5	11,575	0	0.0000	1.0000	100.00
53.5	10,897	0	0.0000	1.0000	100.00
54.5	10,064	0	0.0000	1.0000	100.00
55.5	9,375	0	0.0000	1.0000	100.00
56.5	8,862	0	0.0000	1.0000	100.00
57.5	0	0	0.0000	0.0000	100.00

FortisBC - Electricity

Account #: 360.20 - Distribution Plant - Surface and Mineral

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1960 - 2017



FortisBC - Electricity

Account #: 362.00 - Distribution Plant - Substation Equipment

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	250,885,481	165,876	0.0007	0.9993	100.00
0.5	247,492,405	37,184	0.0002	0.9999	99.93
1.5	243,980,728	63,271	0.0003	0.9997	99.92
2.5	235,038,872	65,926	0.0003	0.9997	99.89
3.5	220,495,529	77,124	0.0004	0.9997	99.86
4.5	217,887,405	109,545	0.0005	0.9995	99.83
5.5	213,341,374	38,929	0.0002	0.9998	99.78
6.5	195,005,815	114,656	0.0006	0.9994	99.76
7.5	174,602,733	32,775	0.0002	0.9998	99.70
8.5	143,263,037	55,702	0.0004	0.9996	99.68
9.5	108,840,040	297,167	0.0027	0.9973	99.64
10.5	87,042,133	105,421	0.0012	0.9988	99.37
11.5	70,143,020	19,527	0.0003	0.9997	99.25
12.5	62,963,545	26,211	0.0004	0.9996	99.22
13.5	62,080,879	68,550	0.0011	0.9989	99.18
14.5	58,329,304	593,692	0.0102	0.9898	99.07
15.5	56,901,850	71,433	0.0013	0.9987	98.06
16.5	54,392,423	87,392	0.0016	0.9984	97.94
17.5	53,068,890	141,481	0.0027	0.9973	97.78
18.5	49,917,150	331,960	0.0067	0.9934	97.52
19.5	47,611,584	162,327	0.0034	0.9966	96.87
20.5	45,271,780	84,638	0.0019	0.9981	96.54
21.5	40,973,926	206,590	0.0050	0.9950	96.36
22.5	36,450,765	287,671	0.0079	0.9921	95.87
23.5	33,028,862	74,908	0.0023	0.9977	95.11
24.5	31,327,535	228,441	0.0073	0.9927	94.89
25.5	30,389,924	207,551	0.0068	0.9932	94.20
26.5	26,713,552	473,285	0.0177	0.9823	93.56
27.5	23,811,812	11,455	0.0005	0.9995	91.90
28.5	22,056,627	338,228	0.0153	0.9847	91.86
29.5	20,783,383	326,354	0.0157	0.9843	90.45
30.5	18,636,666	61,005	0.0033	0.9967	89.03
31.5	16,349,166	54,571	0.0033	0.9967	88.74
32.5	15,074,404	362,943	0.0241	0.9759	88.44
33.5	14,183,305	69,053	0.0049	0.9951	86.31
34.5	11,512,013	164,710	0.0143	0.9857	85.89
35.5	8,493,990	287,526	0.0339	0.9662	84.66
36.5	7,559,514	127,403	0.0169	0.9832	81.79
37.5	5,088,154	35,191	0.0069	0.9931	80.41
38.5	4,965,186	83,736	0.0169	0.9831	79.85
39.5	4,168,561	39,010	0.0094	0.9906	78.50
40.5	3,643,678	79,109	0.0217	0.9783	77.77
41.5	3,249,818	64,964	0.0200	0.9800	76.08
42.5	2,976,274	102,993	0.0346	0.9654	74.56
43.5	2,627,462	38,365	0.0146	0.9854	71.98

FortisBC - Electricity

Account #: 362.00 - Distribution Plant - Substation Equipment

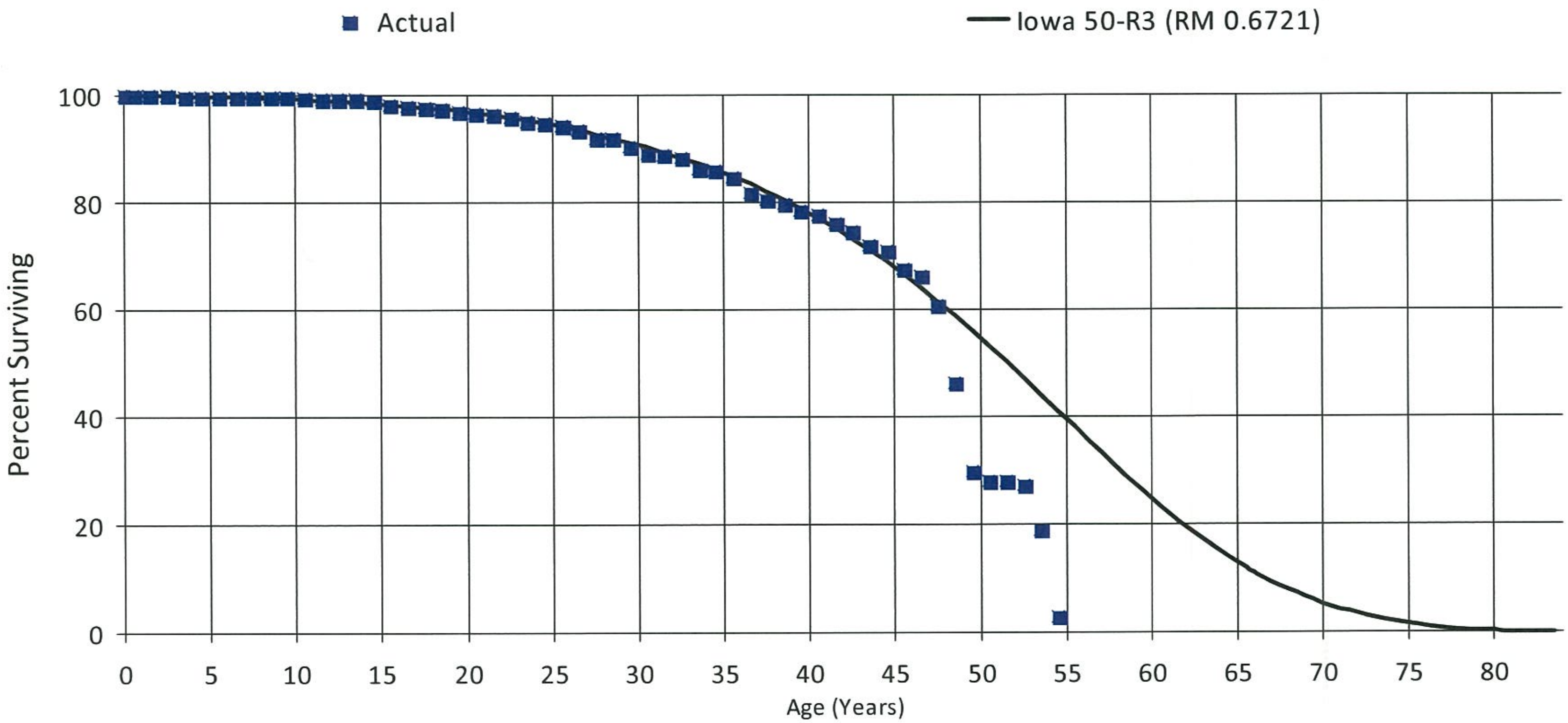
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	2,584,386	120,783	0.0467	0.9533	70.93
45.5	2,441,642	46,235	0.0189	0.9811	67.61
46.5	2,347,335	198,275	0.0845	0.9155	66.33
47.5	2,128,440	504,130	0.2369	0.7632	60.73
48.5	1,566,311	558,630	0.3567	0.6434	46.35
49.5	992,152	54,959	0.0554	0.9446	29.82
50.5	935,805	3,162	0.0034	0.9966	28.17
51.5	900,455	29,422	0.0327	0.9673	28.07
52.5	869,270	264,704	0.3045	0.6955	27.15
53.5	593,092	500,874	0.8445	0.1555	18.88
54.5	91,751	74,710	0.8143	0.1857	2.94

FortisBC - Electricity

Account #: 362.00 - Distribution Plant - Substation Equipment

Actual and Smooth Survivor Curves

Placement Band - 1950 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 364.00 - Distribution Plant - Poles, Towers and Fixtures

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	214,975,472	259,844	0.0012	0.9988	100.00
0.5	204,000,026	127,674	0.0006	0.9994	99.88
1.5	194,852,811	108,103	0.0006	0.9995	99.82
2.5	184,839,532	371,909	0.0020	0.9980	99.77
3.5	171,935,578	252,386	0.0015	0.9985	99.57
4.5	165,979,080	168,183	0.0010	0.9990	99.42
5.5	155,248,384	144,922	0.0009	0.9991	99.32
6.5	146,681,804	111,981	0.0008	0.9992	99.23
7.5	135,359,290	136,319	0.0010	0.9990	99.15
8.5	124,186,416	195,095	0.0016	0.9984	99.05
9.5	111,467,156	599,510	0.0054	0.9946	98.89
10.5	100,855,941	134,272	0.0013	0.9987	98.36
11.5	89,023,436	108,605	0.0012	0.9988	98.23
12.5	80,797,034	265,900	0.0033	0.9967	98.11
13.5	75,020,752	124,481	0.0017	0.9983	97.79
14.5	68,961,917	132,270	0.0019	0.9981	97.63
15.5	65,804,673	79,944	0.0012	0.9988	97.44
16.5	61,336,566	208,386	0.0034	0.9966	97.32
17.5	58,034,011	256,262	0.0044	0.9956	96.99
18.5	55,004,348	70,850	0.0013	0.9987	96.56
19.5	52,363,898	342,649	0.0065	0.9935	96.44
20.5	48,319,022	377,184	0.0078	0.9922	95.81
21.5	45,499,727	58,372	0.0013	0.9987	95.06
22.5	41,881,654	108,549	0.0026	0.9974	94.94
23.5	38,368,899	404,914	0.0106	0.9895	94.69
24.5	35,286,007	61,864	0.0018	0.9983	93.69
25.5	33,181,047	27,501	0.0008	0.9992	93.53
26.5	30,969,098	385,394	0.0124	0.9876	93.45
27.5	28,519,151	699,613	0.0245	0.9755	92.29
28.5	26,051,140	40,101	0.0015	0.9985	90.03
29.5	24,526,211	274,983	0.0112	0.9888	89.89
30.5	23,052,185	127,379	0.0055	0.9945	88.88
31.5	21,553,743	336,427	0.0156	0.9844	88.39
32.5	15,409,670	111,094	0.0072	0.9928	87.01
33.5	14,026,695	25,369	0.0018	0.9982	86.38
34.5	12,713,795	31,932	0.0025	0.9975	86.22
35.5	11,073,968	155,801	0.0141	0.9859	86.00
36.5	9,144,722	25,119	0.0028	0.9973	84.79
37.5	9,119,604	62,828	0.0069	0.9931	84.56
38.5	8,051,095	23,692	0.0029	0.9971	83.98
39.5	6,888,638	21,782	0.0032	0.9968	83.73
40.5	6,084,705	15,398	0.0025	0.9975	83.47
41.5	5,256,897	16,948	0.0032	0.9968	83.26
42.5	4,588,324	33,990	0.0074	0.9926	82.99
43.5	4,119,099	14,037	0.0034	0.9966	82.38

FortisBC - Electricity

Account #: 364.00 - Distribution Plant - Poles, Towers and Fixtures

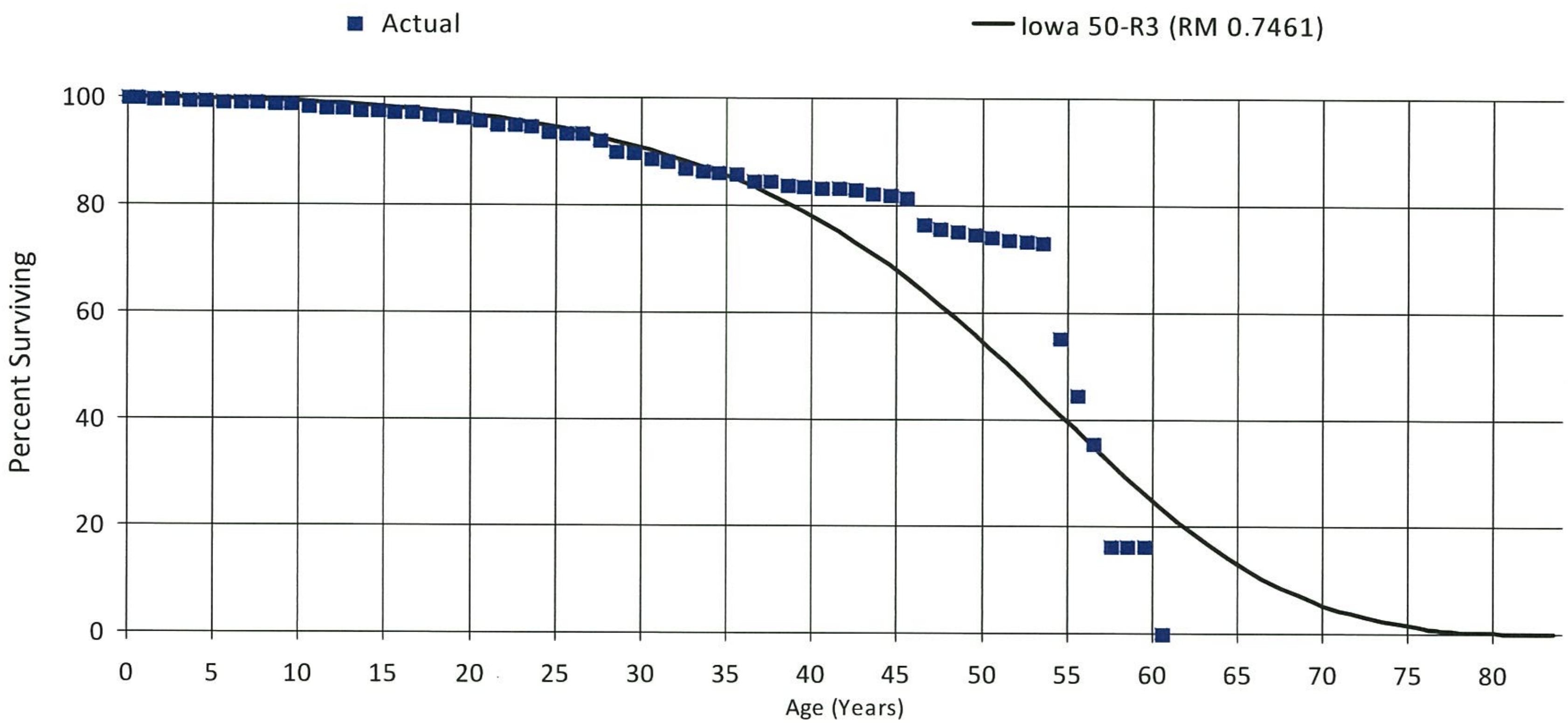
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	3,821,345	19,855	0.0052	0.9948	82.10
45.5	3,553,845	220,111	0.0619	0.9381	81.67
46.5	3,142,775	36,483	0.0116	0.9884	76.61
47.5	2,937,845	20,213	0.0069	0.9931	75.72
48.5	2,732,540	14,060	0.0052	0.9949	75.20
49.5	2,536,866	14,536	0.0057	0.9943	74.81
50.5	2,337,262	18,562	0.0079	0.9921	74.38
51.5	2,157,402	9,337	0.0043	0.9957	73.79
52.5	1,943,182	6,439	0.0033	0.9967	73.47
53.5	1,819,435	443,114	0.2435	0.7565	73.23
54.5	1,224,683	235,195	0.1921	0.8080	55.40
55.5	865,432	176,222	0.2036	0.7964	44.76
56.5	599,975	324,480	0.5408	0.4592	35.65
57.5	11,555	0	0.0000	1.0000	16.37
58.5	11,555	0	0.0000	1.0000	16.37
59.5	11,555	11,555	1.0000	0.0000	16.37
60.5	0	0	0.0000	0.0000	0.00

FortisBC - Electricity

Account #: 364.00 - Distribution Plant - Poles, Towers and Fixtures

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017 Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 365.00 - Distribution Plant - Conductors and Devices

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	346,548,260	126,579	0.0004	0.9996	100.00
0.5	329,489,749	256,275	0.0008	0.9992	99.96
1.5	314,436,054	95,233	0.0003	0.9997	99.88
2.5	298,799,726	73,662	0.0003	0.9998	99.85
3.5	279,280,794	152,377	0.0006	0.9995	99.83
4.5	270,129,365	272,431	0.0010	0.9990	99.78
5.5	255,108,783	470,944	0.0019	0.9982	99.68
6.5	240,376,392	134,452	0.0006	0.9994	99.50
7.5	223,217,767	223,053	0.0010	0.9990	99.44
8.5	206,193,202	176,826	0.0009	0.9991	99.34
9.5	186,420,400	1,611,578	0.0086	0.9914	99.25
10.5	167,626,295	121,319	0.0007	0.9993	98.39
11.5	148,969,118	332,056	0.0022	0.9978	98.32
12.5	136,895,927	126,780	0.0009	0.9991	98.10
13.5	128,734,338	178,373	0.0014	0.9986	98.01
14.5	119,626,999	482,273	0.0040	0.9960	97.87
15.5	114,361,361	203,424	0.0018	0.9982	97.48
16.5	106,292,403	155,681	0.0015	0.9985	97.31
17.5	100,583,963	45,220	0.0005	0.9996	97.17
18.5	95,617,138	116,011	0.0012	0.9988	97.13
19.5	91,098,542	112,257	0.0012	0.9988	97.01
20.5	84,320,493	657,622	0.0078	0.9922	96.89
21.5	79,242,488	81,047	0.0010	0.9990	96.13
22.5	72,828,963	113,408	0.0016	0.9984	96.03
23.5	66,892,656	77,314	0.0012	0.9988	95.88
24.5	62,077,980	209,409	0.0034	0.9966	95.77
25.5	58,246,478	38,468	0.0007	0.9993	95.45
26.5	54,285,857	132,566	0.0024	0.9976	95.39
27.5	50,323,080	776,353	0.0154	0.9846	95.16
28.5	46,394,402	42,067	0.0009	0.9991	93.69
29.5	43,643,379	639,616	0.0147	0.9853	93.60
30.5	40,823,989	224,735	0.0055	0.9945	92.23
31.5	38,107,465	256,077	0.0067	0.9933	91.72
32.5	31,679,399	703,242	0.0222	0.9778	91.10
33.5	28,657,679	237,623	0.0083	0.9917	89.08
34.5	26,075,012	20,971	0.0008	0.9992	88.34
35.5	23,160,564	463,738	0.0200	0.9800	88.27
36.5	19,472,058	1,137,132	0.0584	0.9416	86.50
37.5	18,334,926	190,350	0.0104	0.9896	81.45
38.5	16,302,933	151,484	0.0093	0.9907	80.60
39.5	14,056,043	57,050	0.0041	0.9959	79.85
40.5	12,508,088	19,267	0.0015	0.9985	79.53
41.5	10,960,820	576,234	0.0526	0.9474	79.41
42.5	9,168,119	7,612	0.0008	0.9992	75.24
43.5	8,335,188	6,772	0.0008	0.9992	75.18

FortisBC - Electricity

Account #: 365.00 - Distribution Plant - Conductors and Devices

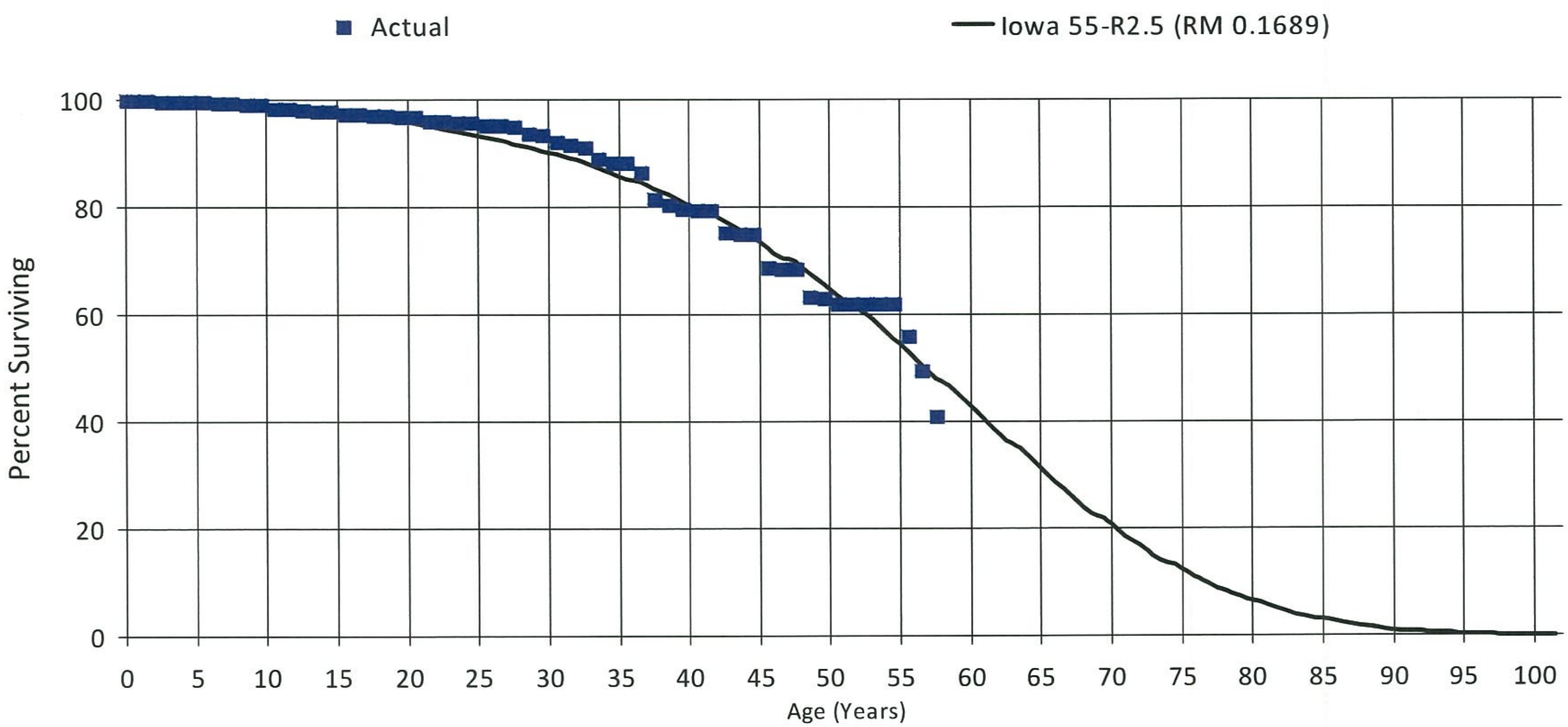
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	7,805,940	644,772	0.0826	0.9174	75.12
45.5	6,686,277	29,000	0.0043	0.9957	68.92
46.5	6,289,901	5,785	0.0009	0.9991	68.62
47.5	5,953,038	448,020	0.0753	0.9247	68.56
48.5	5,145,059	18,868	0.0037	0.9963	63.40
49.5	4,772,797	74,572	0.0156	0.9844	63.17
50.5	4,357,269	2,961	0.0007	0.9993	62.18
51.5	4,051,847	3,471	0.0009	0.9991	62.14
52.5	3,652,787	2,783	0.0008	0.9992	62.09
53.5	3,416,792	2,781	0.0008	0.9992	62.04
54.5	3,122,212	299,267	0.0959	0.9042	61.99
55.5	2,582,852	298,321	0.1155	0.8845	56.05
56.5	2,112,750	367,172	0.1738	0.8262	49.58
57.5	0	0	0.0000	0.0000	40.96

FortisBC - Electricity

Account #: 365.00 - Distribution Plant - Conductors and Devices

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1950 - 2017



FortisBC - Electricity

Account #: 368.00 - Distribution Plant - Line Transformers

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	170,376,395	215,476	0.0013	0.9987	100.00
0.5	159,998,728	347,594	0.0022	0.9978	99.87
1.5	151,494,648	395,807	0.0026	0.9974	99.65
2.5	142,617,138	293,419	0.0021	0.9979	99.39
3.5	132,464,054	360,841	0.0027	0.9973	99.19
4.5	127,606,435	1,101,741	0.0086	0.9914	98.92
5.5	119,823,465	555,697	0.0046	0.9954	98.07
6.5	111,890,466	316,855	0.0028	0.9972	97.61
7.5	102,770,593	320,990	0.0031	0.9969	97.33
8.5	93,556,878	325,037	0.0035	0.9965	97.03
9.5	82,920,643	383,526	0.0046	0.9954	96.69
10.5	71,352,828	246,664	0.0035	0.9965	96.24
11.5	59,496,600	256,729	0.0043	0.9957	95.91
12.5	53,219,497	479,483	0.0090	0.9910	95.50
13.5	48,201,308	272,472	0.0057	0.9944	94.64
14.5	43,334,127	1,007,638	0.0233	0.9768	94.11
15.5	38,843,304	182,356	0.0047	0.9953	91.92
16.5	35,990,097	81,666	0.0023	0.9977	91.49
17.5	34,077,927	160,186	0.0047	0.9953	91.28
18.5	32,397,690	237,858	0.0073	0.9927	90.85
19.5	30,690,170	125,277	0.0041	0.9959	90.18
20.5	28,320,502	132,600	0.0047	0.9953	89.81
21.5	26,730,813	151,917	0.0057	0.9943	89.39
22.5	24,455,186	95,156	0.0039	0.9961	88.88
23.5	22,697,966	98,878	0.0044	0.9956	88.53
24.5	21,090,796	56,849	0.0027	0.9973	88.14
25.5	19,850,038	95,005	0.0048	0.9952	87.90
26.5	18,471,399	176,232	0.0095	0.9905	87.48
27.5	17,124,015	303,873	0.0178	0.9823	86.65
28.5	15,797,514	237,800	0.0151	0.9850	85.11
29.5	14,711,549	58,831	0.0040	0.9960	83.83
30.5	13,951,097	195,916	0.0140	0.9860	83.49
31.5	12,956,463	58,298	0.0045	0.9955	82.32
32.5	10,134,615	65,952	0.0065	0.9935	81.95
33.5	9,326,699	506,827	0.0543	0.9457	81.42
34.5	8,059,464	1,611,073	0.1999	0.8001	77.00
35.5	6,229,209	1,176,859	0.1889	0.8111	61.61
36.5	5,052,350	519,782	0.1029	0.8971	49.97
37.5	4,532,568	244,480	0.0539	0.9461	44.83
38.5	4,288,089	131,526	0.0307	0.9693	42.41
39.5	4,156,563	98,636	0.0237	0.9763	41.11
40.5	4,057,926	333,162	0.0821	0.9179	40.13
41.5	3,724,764	173,726	0.0466	0.9534	36.84
42.5	3,551,038	177,296	0.0499	0.9501	35.12
43.5	3,373,742	381,155	0.1130	0.8870	33.37

FortisBC - Electricity

Account #: 368.00 - Distribution Plant - Line Transformers

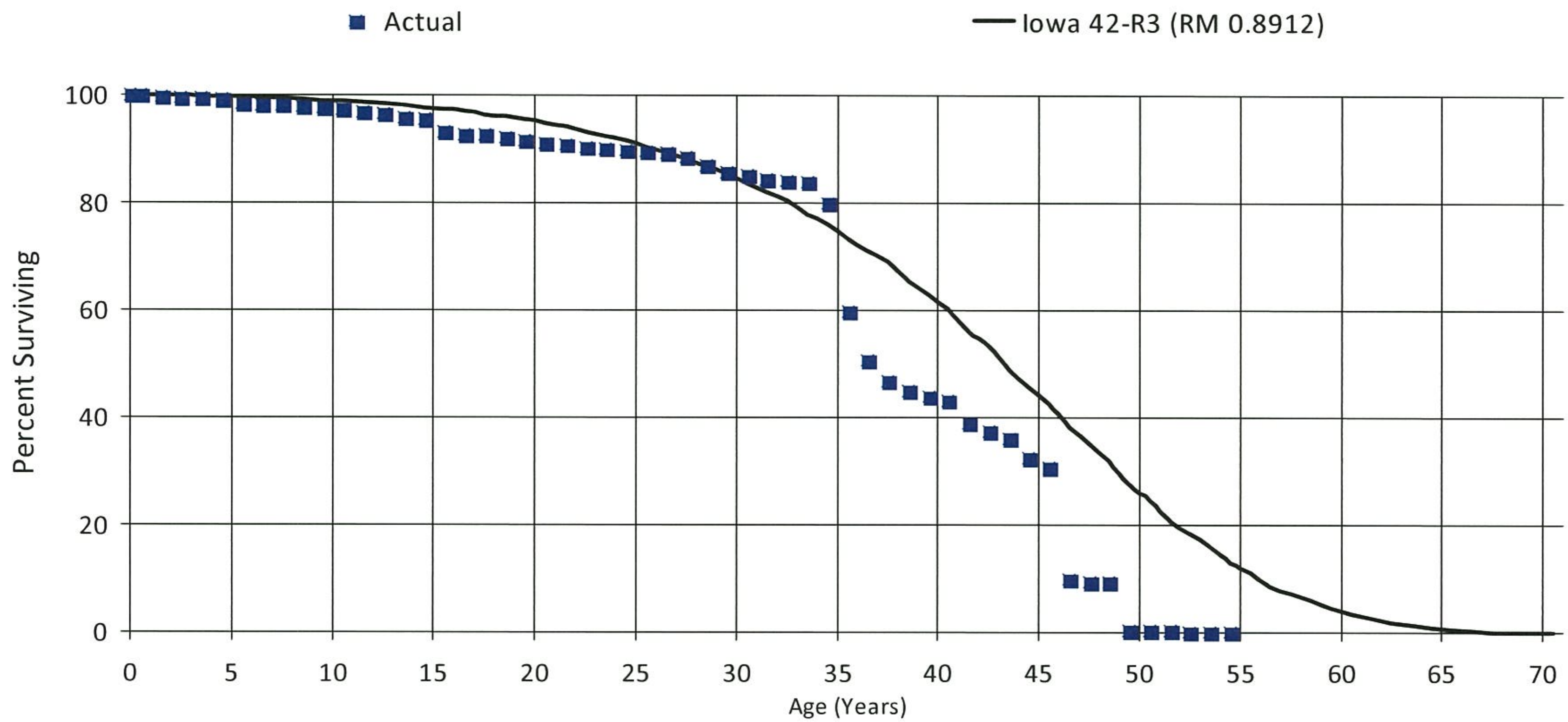
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	2,992,587	168,069	0.0562	0.9438	29.60
45.5	2,824,517	1,494,823	0.5292	0.4708	27.94
46.5	1,329,694	53,834	0.0405	0.9595	13.15
47.5	1,275,860	15,121	0.0119	0.9882	12.62
48.5	1,260,739	1,224,850	0.9715	0.0285	12.47
49.5	35,889	0	0.0000	1.0000	0.36
50.5	35,889	0	0.0000	1.0000	0.36
51.5	35,889	24,891	0.6936	0.3065	0.36
52.5	10,998	0	0.0000	1.0000	0.11
53.5	10,998	10,998	1.0000	0.0000	0.11
54.5	0	0	0.0000	0.0000	0.00

Fortis BC Inc.

Account #: 368.00 - Distribution Plant - Line Transformers

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 369.00 - Services

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	15,041,450	0	0.0000	1.0000	100.00
0.5	15,041,450	0	0.0000	1.0000	100.00
1.5	15,041,450	0	0.0000	1.0000	100.00
2.5	15,041,450	94	0.0000	1.0000	100.00
3.5	15,041,356	28	0.0000	1.0000	100.00
4.5	15,041,328	5,454,914	0.3627	0.6373	100.00
5.5	9,297,658	312	0.0000	1.0000	63.73
6.5	8,918,588	0	0.0000	1.0000	63.73
7.5	8,911,940	0	0.0000	1.0000	63.73
8.5	8,706,758	1,996	0.0002	0.9998	63.73
9.5	8,523,394	0	0.0000	1.0000	63.72
10.5	8,382,434	0	0.0000	1.0000	63.72
11.5	8,199,738	2	0.0000	1.0000	63.72
12.5	7,991,368	0	0.0000	1.0000	63.72
13.5	7,887,034	238	0.0000	1.0000	63.72
14.5	7,828,987	0	0.0000	1.0000	63.72
15.5	7,811,085	3,877	0.0005	0.9995	63.72
16.5	7,296,767	29	0.0000	1.0000	63.69
17.5	6,954,201	0	0.0000	1.0000	63.69
18.5	6,648,547	0	0.0000	1.0000	63.69
19.5	6,332,073	0	0.0000	1.0000	63.69
20.5	5,937,903	0	0.0000	1.0000	63.69
21.5	5,670,027	0	0.0000	1.0000	63.69
22.5	5,271,405	0	0.0000	1.0000	63.69
23.5	4,887,810	0	0.0000	1.0000	63.69
24.5	4,618,066	0	0.0000	1.0000	63.69
25.5	4,380,227	0	0.0000	1.0000	63.69
26.5	4,138,177	0	0.0000	1.0000	63.69
27.5	3,891,199	0	0.0000	1.0000	63.69
28.5	3,656,828	0	0.0000	1.0000	63.69
29.5	3,472,105	0	0.0000	1.0000	63.69
30.5	3,332,862	48,297	0.0145	0.9855	63.69
31.5	3,129,842	0	0.0000	1.0000	62.77
32.5	1,769,232	16	0.0000	1.0000	62.77
33.5	1,632,124	0	0.0000	1.0000	62.77
34.5	1,494,431	0	0.0000	1.0000	62.77
35.5	1,324,316	0	0.0000	1.0000	62.77
36.5	1,134,091	0	0.0000	1.0000	62.77
37.5	991,094	0	0.0000	1.0000	62.77
38.5	881,999	0	0.0000	1.0000	62.77
39.5	758,605	0	0.0000	1.0000	62.77
40.5	669,839	0	0.0000	1.0000	62.77
41.5	579,539	0	0.0000	1.0000	62.77
42.5	505,998	0	0.0000	1.0000	62.77
43.5	456,656	0	0.0000	1.0000	62.77

FortisBC - Electricity

Account #: 369.00 - Services

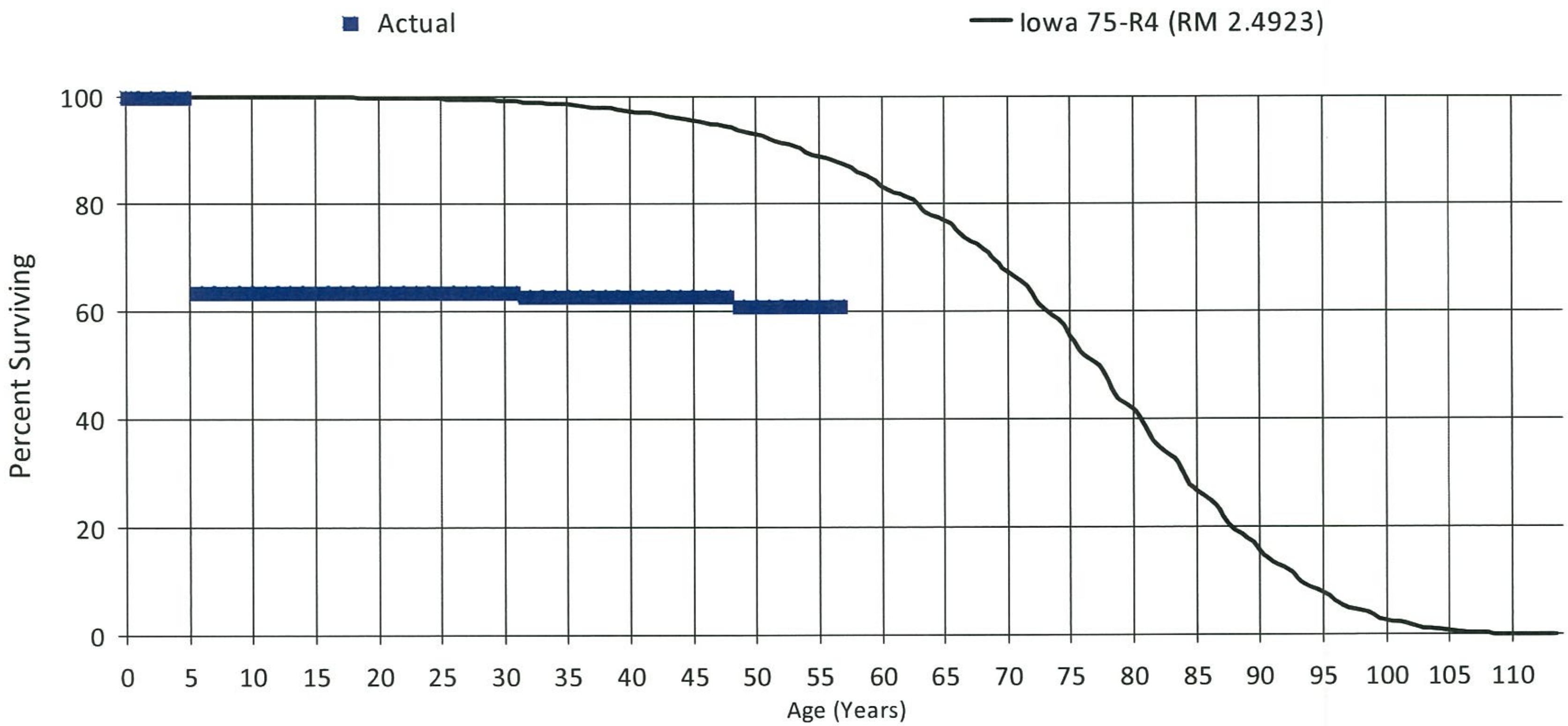
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	425,951	0	0.0000	1.0000	62.77
45.5	397,148	0	0.0000	1.0000	62.77
46.5	375,204	0	0.0000	1.0000	62.77
47.5	354,800	9,814	0.0277	0.9723	62.77
48.5	323,466	0	0.0000	1.0000	61.03
49.5	302,337	0	0.0000	1.0000	61.03
50.5	282,378	0	0.0000	1.0000	61.03
51.5	264,611	0	0.0000	1.0000	61.03
52.5	241,414	0	0.0000	1.0000	61.03
53.5	227,272	0	0.0000	1.0000	61.03
54.5	209,906	0	0.0000	1.0000	61.03
55.5	195,533	0	0.0000	1.0000	61.03
56.5	184,837	0	0.0000	1.0000	61.03

FortisBC - Electricity

Account #: 369.00 - Services

Actual and Smooth Survivor Curves

Placement Band - 1960 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity
Account #: 371.00 - Installations on Customers' Premises

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	1,282,160	519	0.0004	0.9996	100.00
0.5	1,281,641	948	0.0007	0.9993	99.96
1.5	1,280,693	4,867	0.0038	0.9962	99.89
2.5	1,275,827	1,904	0.0015	0.9985	99.51
3.5	1,273,923	1,219	0.0010	0.9990	99.36
4.5	1,272,703	86,050	0.0676	0.9324	99.26
5.5	1,186,653	21,600	0.0182	0.9818	92.55
6.5	1,165,053	18,044	0.0155	0.9845	90.87
7.5	1,147,010	16,993	0.0148	0.9852	89.46
8.5	1,130,017	10,800	0.0096	0.9904	88.13
9.5	1,119,217	69,046	0.0617	0.9383	87.29
10.5	1,050,171	7,652	0.0073	0.9927	81.91
11.5	1,042,519	13,029	0.0125	0.9875	81.31
12.5	1,029,489	24,737	0.0240	0.9760	80.29
13.5	1,004,752	4,893	0.0049	0.9951	78.36
14.5	999,859	9,933	0.0099	0.9901	77.98
15.5	989,926	4,002	0.0040	0.9960	77.21
16.5	918,156	8,614	0.0094	0.9906	76.90
17.5	859,783	2	0.0000	1.0000	76.18
18.5	814,840	44	0.0001	1.0000	76.18
19.5	776,237	2,353	0.0030	0.9970	76.18
20.5	714,183	0	0.0000	1.0000	75.95
21.5	674,777	3,473	0.0052	0.9949	75.95
22.5	615,158	706	0.0012	0.9989	75.56
23.5	558,990	84	0.0002	0.9999	75.47
24.5	517,505	30,528	0.0590	0.9410	75.46
25.5	455,155	0	0.0000	1.0000	71.01
26.5	420,775	0	0.0000	1.0000	71.01
27.5	388,090	0	0.0000	1.0000	71.01
28.5	360,966	677	0.0019	0.9981	71.01
29.5	336,432	0	0.0000	1.0000	70.88
30.5	317,119	0	0.0000	1.0000	70.88
31.5	294,761	0	0.0000	1.0000	70.88
32.5	272,365	112	0.0004	0.9996	70.88
33.5	251,375	0	0.0000	1.0000	70.85
34.5	230,294	0	0.0000	1.0000	70.85
35.5	204,078	222	0.0011	0.9989	70.85
36.5	174,540	0	0.0000	1.0000	70.77
37.5	152,503	0	0.0000	1.0000	70.77
38.5	135,690	0	0.0000	1.0000	70.77
39.5	116,674	0	0.0000	1.0000	70.77
40.5	102,994	0	0.0000	1.0000	70.77
41.5	89,078	0	0.0000	1.0000	70.77
42.5	77,745	1,278	0.0164	0.9836	70.77
43.5	68,863	0	0.0000	1.0000	69.61

FortisBC - Electricity

Account #: 371.00 - Installations on Customers' Premises

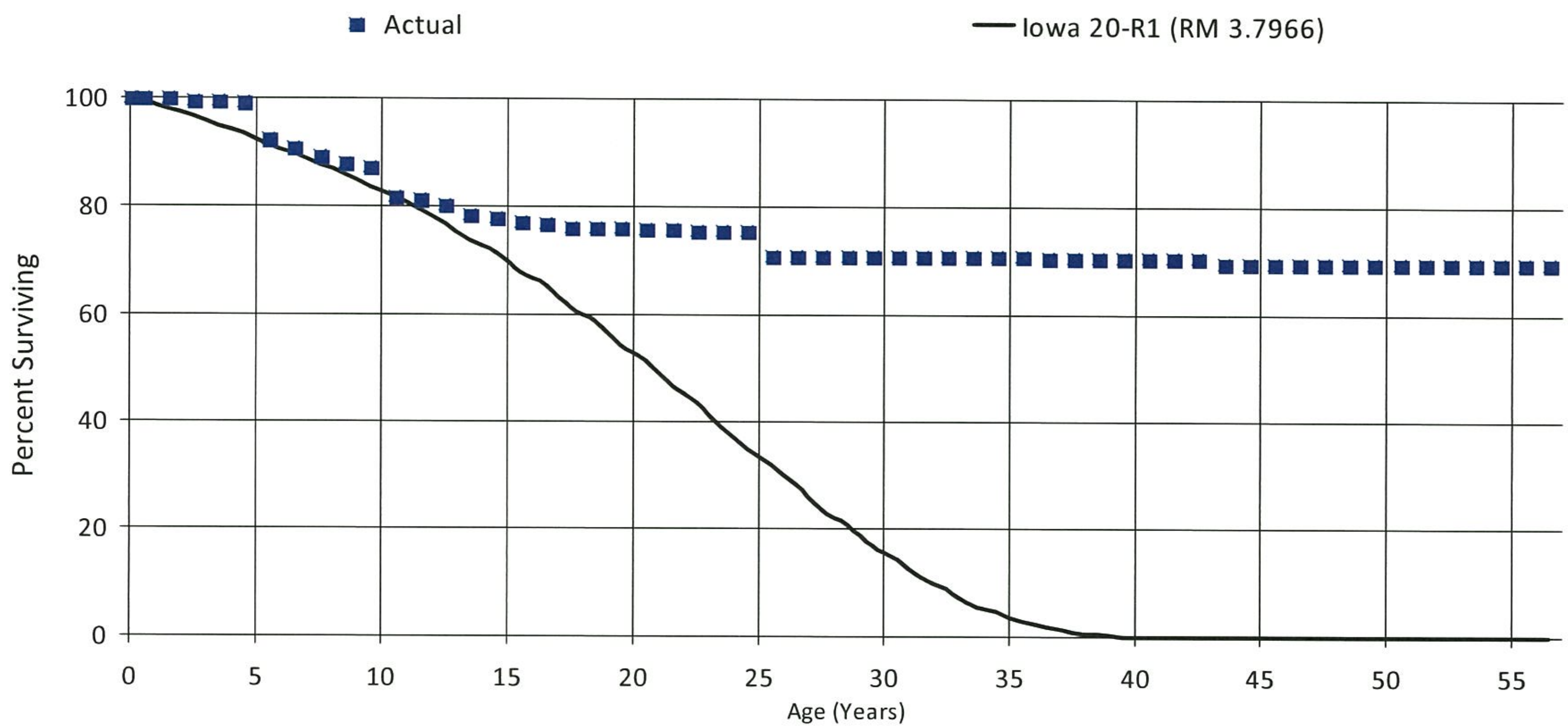
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	64,131	0	0.0000	1.0000	69.61
45.5	59,692	0	0.0000	1.0000	69.61
46.5	56,310	0	0.0000	1.0000	69.61
47.5	53,166	0	0.0000	1.0000	69.61
48.5	49,849	0	0.0000	1.0000	69.61
49.5	46,593	0	0.0000	1.0000	69.61
50.5	43,517	0	0.0000	1.0000	69.61
51.5	40,779	0	0.0000	1.0000	69.61
52.5	37,204	0	0.0000	1.0000	69.61
53.5	35,025	0	0.0000	1.0000	69.61
54.5	32,349	0	0.0000	1.0000	69.61
55.5	30,134	0	0.0000	1.0000	69.61
56.5	28,485	0	0.0000	1.0000	69.61

FortisBC - Electricity

Account #: 371.00 - Installations on Customers' Premises

Actual and Smooth Survivor Curves

Placement Band - 1960 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 373.00 - Street Lighting and Signal Systems

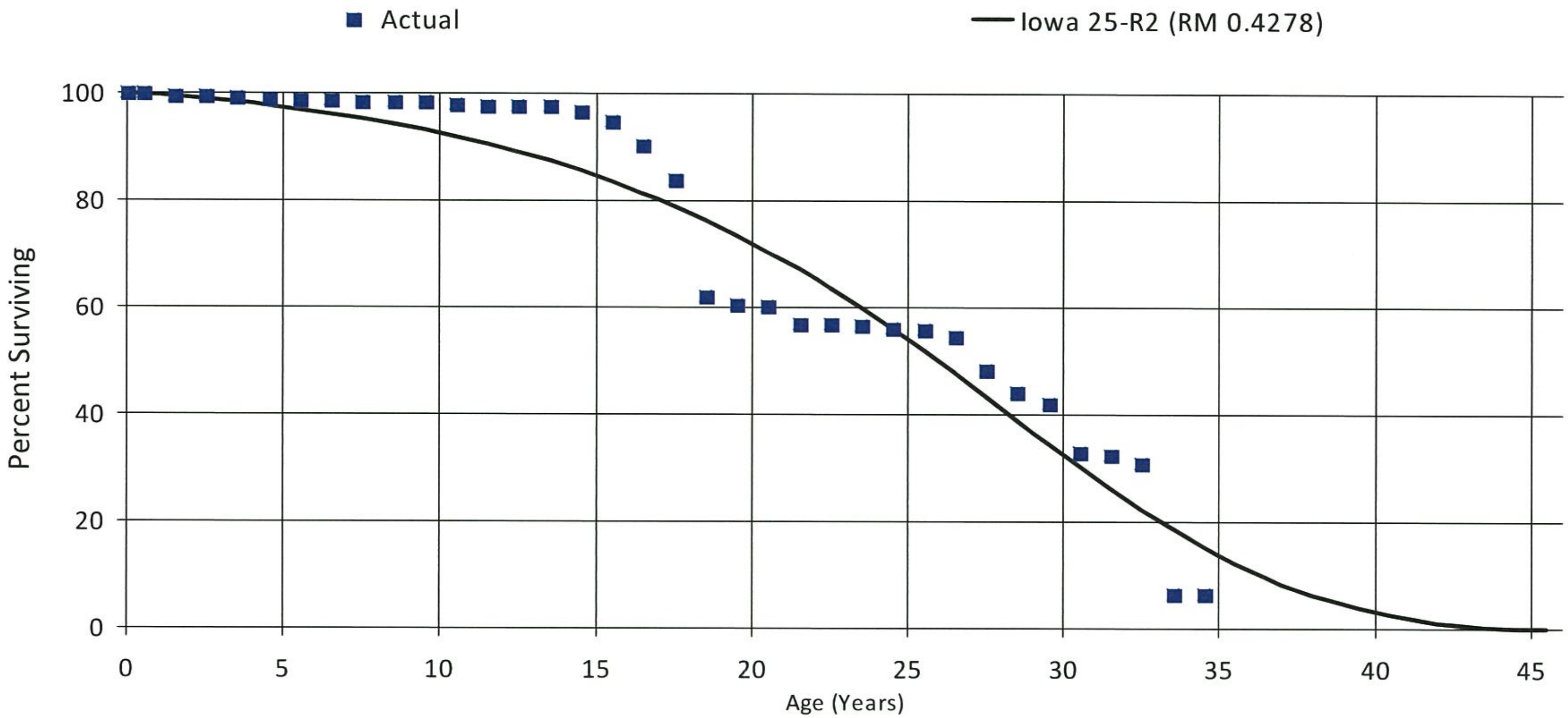
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	14,229,842	1,095	0.0001	0.9999	100.00
0.5	13,955,279	68,404	0.0049	0.9951	99.99
1.5	13,688,276	11,721	0.0009	0.9991	99.50
2.5	13,560,879	7,895	0.0006	0.9994	99.41
3.5	13,461,217	43,451	0.0032	0.9968	99.35
4.5	13,406,990	37,126	0.0028	0.9972	99.03
5.5	13,348,251	14,826	0.0011	0.9989	98.76
6.5	12,640,235	15,706	0.0012	0.9988	98.65
7.5	11,363,195	9,365	0.0008	0.9992	98.53
8.5	10,009,850	12,312	0.0012	0.9988	98.45
9.5	8,263,403	26,004	0.0032	0.9969	98.33
10.5	6,565,392	16,373	0.0025	0.9975	98.02
11.5	4,963,398	5,835	0.0012	0.9988	97.78
12.5	3,885,294	4,253	0.0011	0.9989	97.66
13.5	3,009,241	28,053	0.0093	0.9907	97.55
14.5	2,033,055	38,188	0.0188	0.9812	96.64
15.5	1,994,868	93,834	0.0470	0.9530	94.83
16.5	1,819,423	131,014	0.0720	0.9280	90.37
17.5	1,634,701	426,064	0.2606	0.7394	83.86
18.5	1,168,718	29,273	0.0251	0.9750	62.00
19.5	1,098,996	3,103	0.0028	0.9972	60.45
20.5	1,029,078	56,076	0.0545	0.9455	60.28
21.5	937,942	3,177	0.0034	0.9966	57.00
22.5	872,799	3,254	0.0037	0.9963	56.81
23.5	822,923	6,473	0.0079	0.9921	56.60
24.5	770,429	2,981	0.0039	0.9961	56.15
25.5	732,310	19,170	0.0262	0.9738	55.93
26.5	684,068	77,518	0.1133	0.8867	54.47
27.5	606,550	51,791	0.0854	0.9146	48.30
28.5	554,760	26,803	0.0483	0.9517	44.18
29.5	527,957	113,384	0.2148	0.7852	42.05
30.5	414,573	7,116	0.0172	0.9828	33.02
31.5	407,457	20,309	0.0498	0.9502	32.45
32.5	241,374	189,764	0.7862	0.2138	30.83
33.5	51,610	0	0.0000	1.0000	6.59
34.5	51,610	0	0.0000	1.0000	6.59

FortisBC - Electricity

Account #: 373.00 - Street Lighting and Signal Systems

Actual and Smooth Survivor Curves

Placement Band - 1950 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 390.10 - Structures - Masonry

Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	43,215,617	6,648	0.0002	0.9999	100.00
0.5	26,752,055	0	0.0000	1.0000	99.98
1.5	24,957,308	2,953	0.0001	0.9999	99.98
2.5	24,624,002	47,464	0.0019	0.9981	99.97
3.5	23,915,044	10,393	0.0004	0.9996	99.78
4.5	7,430,681	2,579	0.0004	0.9997	99.74
5.5	7,275,074	23,761	0.0033	0.9967	99.71
6.5	6,914,190	81,270	0.0118	0.9883	99.38
7.5	6,594,564	55,537	0.0084	0.9916	98.21
8.5	6,133,798	21,959	0.0036	0.9964	97.38
9.5	5,683,759	72,658	0.0128	0.9872	97.03
10.5	5,027,981	76,669	0.0153	0.9848	95.79
11.5	4,771,547	84,963	0.0178	0.9822	94.33
12.5	4,633,789	35,488	0.0077	0.9923	92.65
13.5	4,494,928	14,636	0.0033	0.9967	91.94
14.5	4,259,486	137,936	0.0324	0.9676	91.64
15.5	4,016,221	0	0.0000	1.0000	88.67
16.5	3,660,831	4,089	0.0011	0.9989	88.67
17.5	3,641,626	194,672	0.0535	0.9465	88.57
18.5	3,120,534	13,567	0.0044	0.9957	83.84
19.5	3,039,491	59,208	0.0195	0.9805	83.48
20.5	2,886,089	71,340	0.0247	0.9753	81.85
21.5	2,785,896	148,757	0.0534	0.9466	79.83
22.5	2,592,717	19,116	0.0074	0.9926	75.57
23.5	4,857,028	23,881	0.0049	0.9951	75.01
24.5	4,784,427	56,733	0.0119	0.9881	74.64
25.5	4,676,266	48,534	0.0104	0.9896	73.75
26.5	4,336,761	44,631	0.0103	0.9897	72.98
27.5	4,273,039	290,602	0.0680	0.9320	72.23
28.5	3,583,428	4,567	0.0013	0.9987	67.32
29.5	2,939,242	89	0.0000	1.0000	67.23
30.5	2,704,356	2,327	0.0009	0.9991	67.23
31.5	2,699,833	15,896	0.0059	0.9941	67.17
32.5	1,435,309	0	0.0000	1.0000	66.77
33.5	1,411,343	250	0.0002	0.9998	66.77
34.5	1,300,604	250	0.0002	0.9998	66.76
35.5	1,282,577	6,283	0.0049	0.9951	66.75
36.5	1,274,072	231,727	0.1819	0.8181	66.42
37.5	1,040,765	143,890	0.1383	0.8618	54.34
38.5	370,441	0	0.0000	1.0000	46.83
39.5	370,441	11,851	0.0320	0.9680	46.83
40.5	351,159	23,004	0.0655	0.9345	45.33
41.5	306,067	182,490	0.5962	0.4038	42.36
42.5	108,146	0	0.0000	1.0000	17.10
43.5	108,146	0	0.0000	1.0000	17.10

FortisBC - Electricity

Account #: 390.10 - Structures - Masonry

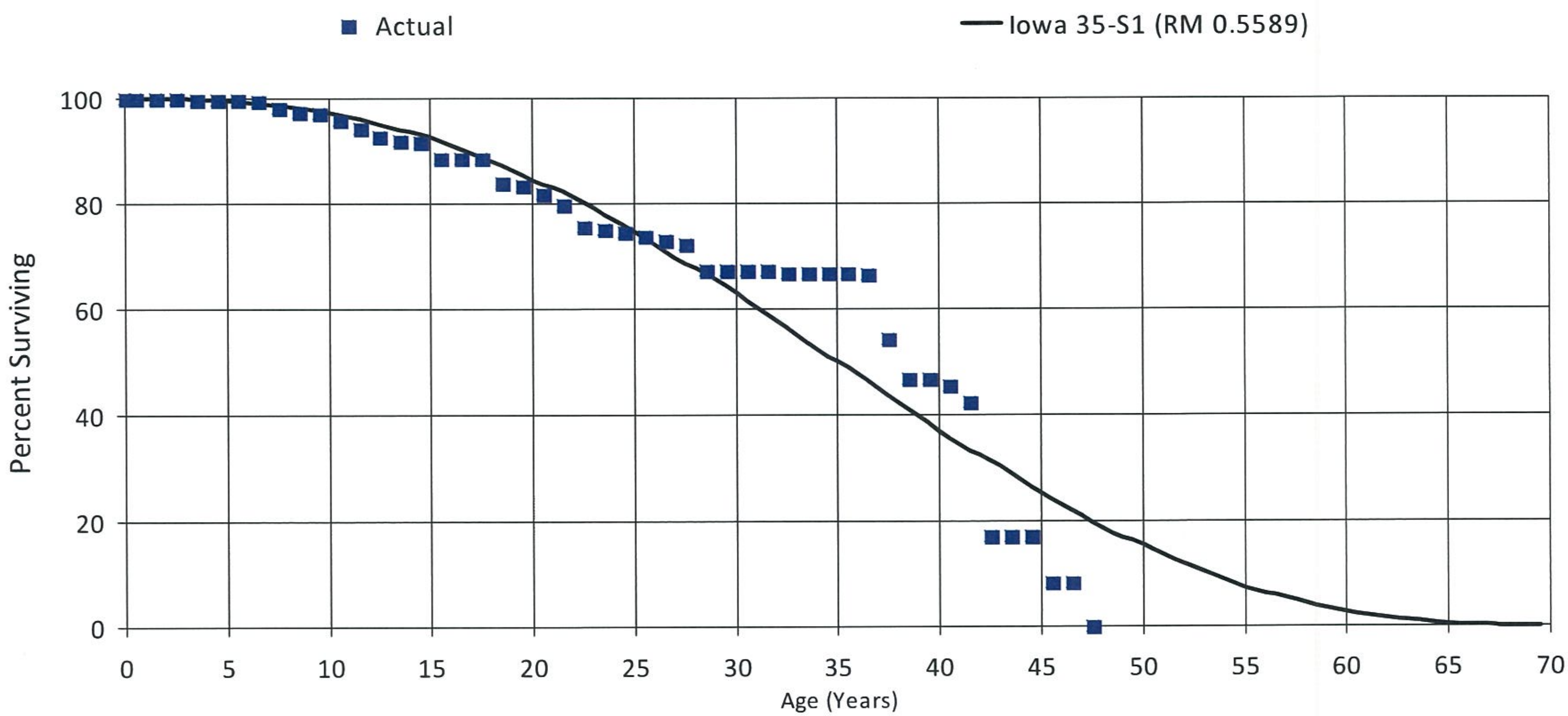
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
44.5	108,146	55,471	0.5129	0.4871	17.10
45.5	52,676	0	0.0000	1.0000	8.33
46.5	52,676	52,676	1.0000	0.0000	8.33
47.5	0	0	0.0000	0.0000	0.00

FortisBC - Electricity

Account #: 390.10 - Structures - Masonry

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017 Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 390.20 - Operations Building

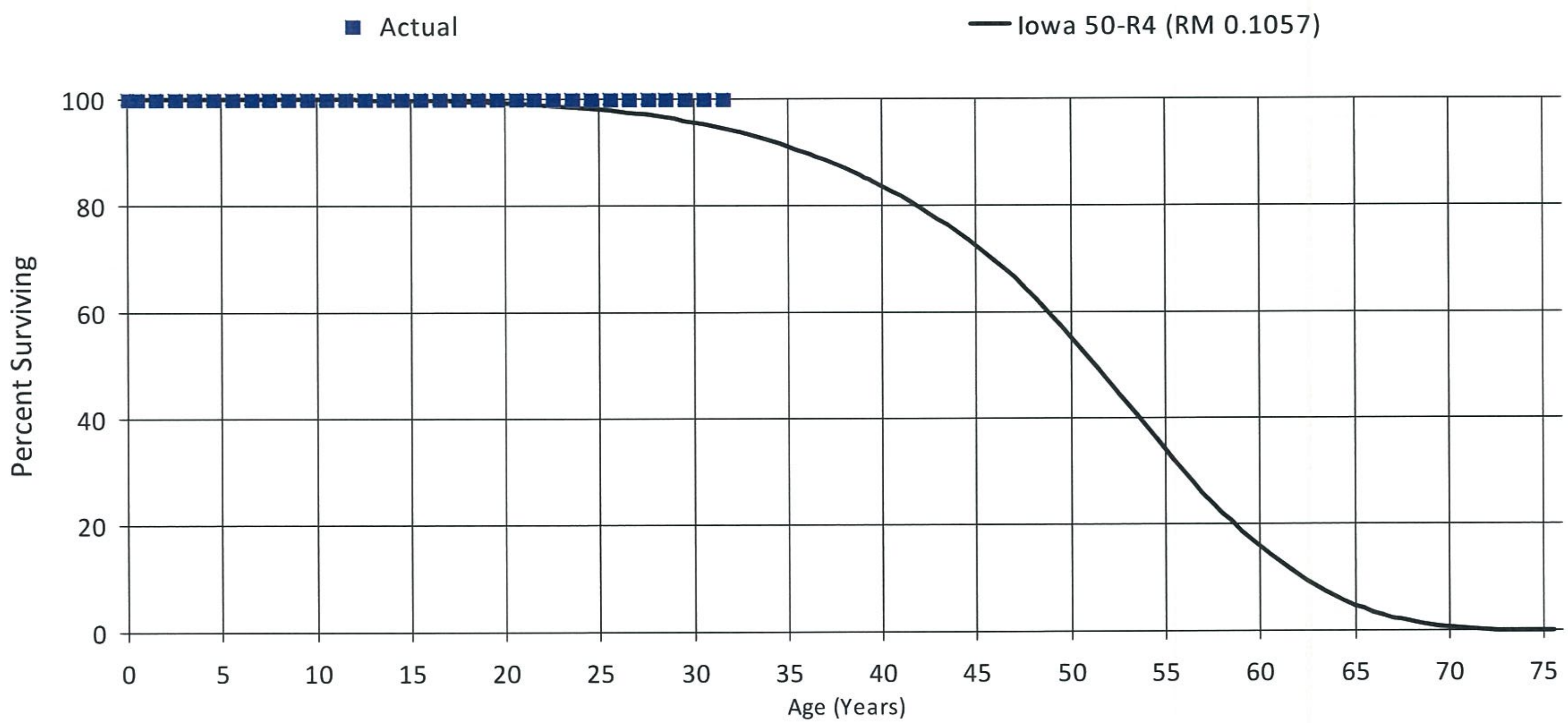
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	16,820,843	0	0.0000	1.0000	100.00
0.5	16,454,026	0	0.0000	1.0000	100.00
1.5	16,377,050	0	0.0000	1.0000	100.00
2.5	16,035,423	0	0.0000	1.0000	100.00
3.5	15,621,464	0	0.0000	1.0000	100.00
4.5	14,955,785	0	0.0000	1.0000	100.00
5.5	13,647,501	0	0.0000	1.0000	100.00
6.5	13,031,664	0	0.0000	1.0000	100.00
7.5	12,770,638	0	0.0000	1.0000	100.00
8.5	12,035,677	0	0.0000	1.0000	100.00
9.5	11,652,310	0	0.0000	1.0000	100.00
10.5	11,109,282	0	0.0000	1.0000	100.00
11.5	10,523,784	0	0.0000	1.0000	100.00
12.5	10,345,473	0	0.0000	1.0000	100.00
13.5	10,370,766	0	0.0000	1.0000	100.00
14.5	5,535,896	0	0.0000	1.0000	100.00
15.5	2,687,371	0	0.0000	1.0000	100.00
16.5	2,687,371	0	0.0000	1.0000	100.00
17.5	2,687,371	0	0.0000	1.0000	100.00
18.5	2,687,371	0	0.0000	1.0000	100.00
19.5	2,687,371	0	0.0000	1.0000	100.00
20.5	2,687,371	0	0.0000	1.0000	100.00
21.5	2,687,371	0	0.0000	1.0000	100.00
22.5	2,687,371	0	0.0000	1.0000	100.00
23.5	344,771	0	0.0000	1.0000	100.00
24.5	53,408	0	0.0000	1.0000	100.00
25.5	53,408	0	0.0000	1.0000	100.00
26.5	53,408	0	0.0000	1.0000	100.00
27.5	53,408	0	0.0000	1.0000	100.00
28.5	53,408	0	0.0000	1.0000	100.00
29.5	53,100	0	0.0000	1.0000	100.00
30.5	44,990	0	0.0000	1.0000	100.00
31.5	0	0	0.0000	0.0000	100.00

FortisBC - Electricity

Account #: 390.20 - Operations Building

Actual and Smooth Survivor Curves

Placement Band - 1980 - 2017   Experience Band - 1940 - 2017



FortisBC - Electricity

Account #: 392.10 - Light Duty Vehicles

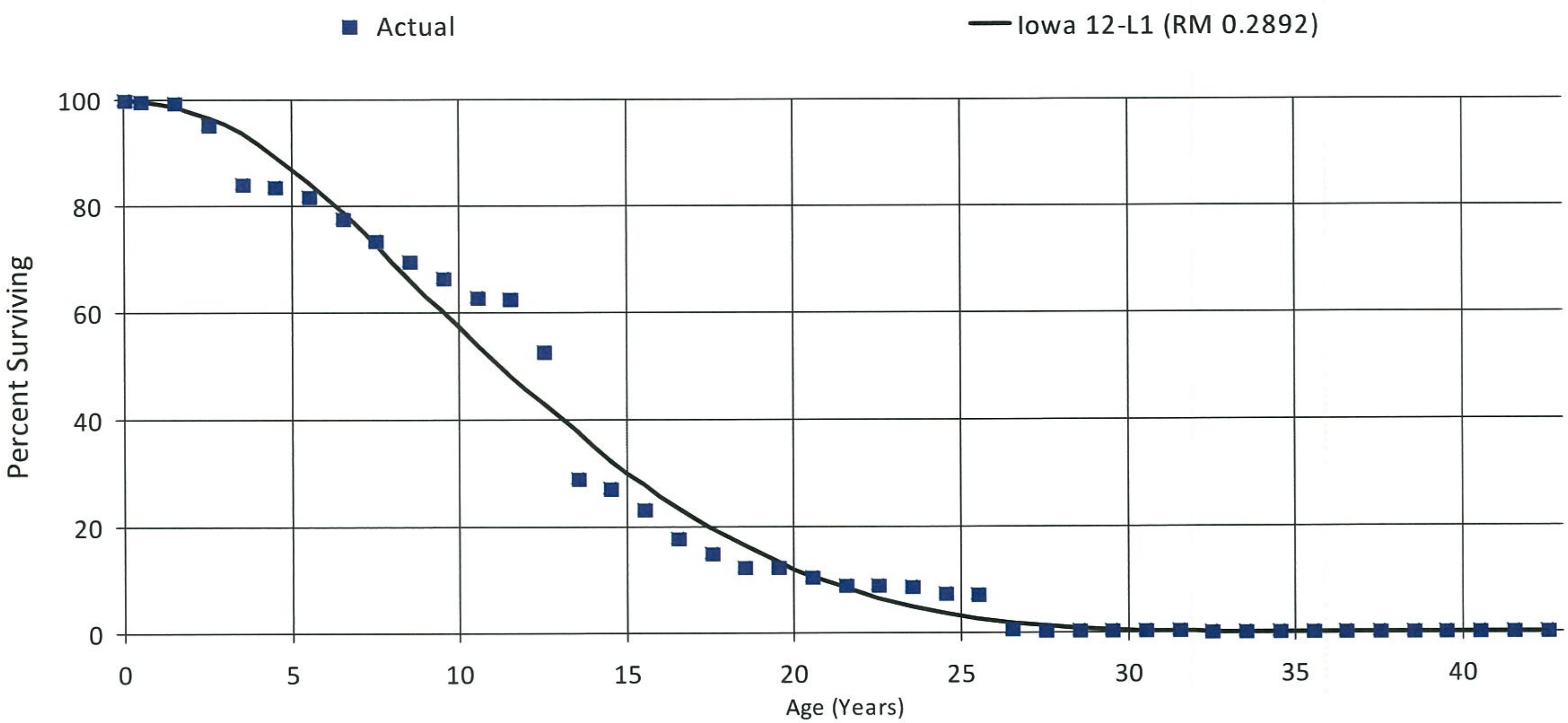
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	21,030,637	70,556	0.0034	0.9967	100.00
0.5	20,615,692	40,162	0.0020	0.9981	99.66
1.5	19,664,216	836,070	0.0425	0.9575	99.47
2.5	18,797,632	2,184,762	0.1162	0.8838	95.24
3.5	16,146,125	124,964	0.0077	0.9923	84.17
4.5	15,152,126	315,707	0.0208	0.9792	83.52
5.5	14,271,865	735,234	0.0515	0.9485	81.78
6.5	12,186,332	650,509	0.0534	0.9466	77.57
7.5	11,485,577	608,827	0.0530	0.9470	73.43
8.5	10,784,572	456,055	0.0423	0.9577	69.54
9.5	9,935,201	539,759	0.0543	0.9457	66.60
10.5	9,351,805	65,070	0.0070	0.9930	62.98
11.5	9,158,837	1,432,254	0.1564	0.8436	62.54
12.5	7,506,365	3,384,920	0.4509	0.5491	52.76
13.5	4,099,675	221,807	0.0541	0.9459	28.97
14.5	3,877,868	586,030	0.1511	0.8489	27.40
15.5	3,283,913	770,595	0.2347	0.7653	23.26
16.5	2,513,318	369,100	0.1469	0.8531	17.80
17.5	2,144,218	392,090	0.1829	0.8171	15.19
18.5	1,752,128	0	0.0000	1.0000	12.41
19.5	1,752,128	249,645	0.1425	0.8575	12.41
20.5	1,502,483	206,682	0.1376	0.8624	10.64
21.5	1,295,801	0	0.0000	1.0000	9.18
22.5	1,232,585	39,922	0.0324	0.9676	9.18
23.5	1,192,663	185,109	0.1552	0.8448	8.88
24.5	1,007,554	28,215	0.0280	0.9720	7.50
25.5	979,339	882,850	0.9015	0.0985	7.29
26.5	96,489	35,514	0.3681	0.6319	0.72
27.5	60,975	0	0.0000	1.0000	0.45
28.5	60,975	0	0.0000	1.0000	0.45
29.5	60,975	0	0.0000	1.0000	0.45
30.5	60,975	0	0.0000	1.0000	0.45
31.5	60,975	11,287	0.1851	0.8149	0.45
32.5	49,688	0	0.0000	1.0000	0.37
33.5	49,688	3,891	0.0783	0.9217	0.37
34.5	45,797	0	0.0000	1.0000	0.34
35.5	45,797	0	0.0000	1.0000	0.34
36.5	45,797	0	0.0000	1.0000	0.34
37.5	45,797	0	0.0000	1.0000	0.34
38.5	45,797	17,435	0.3807	0.6193	0.34
39.5	28,362	0	0.0000	1.0000	0.21
40.5	28,362	0	0.0000	1.0000	0.21
41.5	28,362	0	0.0000	1.0000	0.21
42.5	28,362	28,362	1.0000		0.21

FortisBC - Electricity

Account #: 392.10 - Light Duty Vehicles

Actual and Smooth Survivor Curves

Placement Band - 1940 - 2017 Experience Band - 1940 - 2017



Fortis BC Electrical

Account 392.20 - Heavy Duty Vehicles

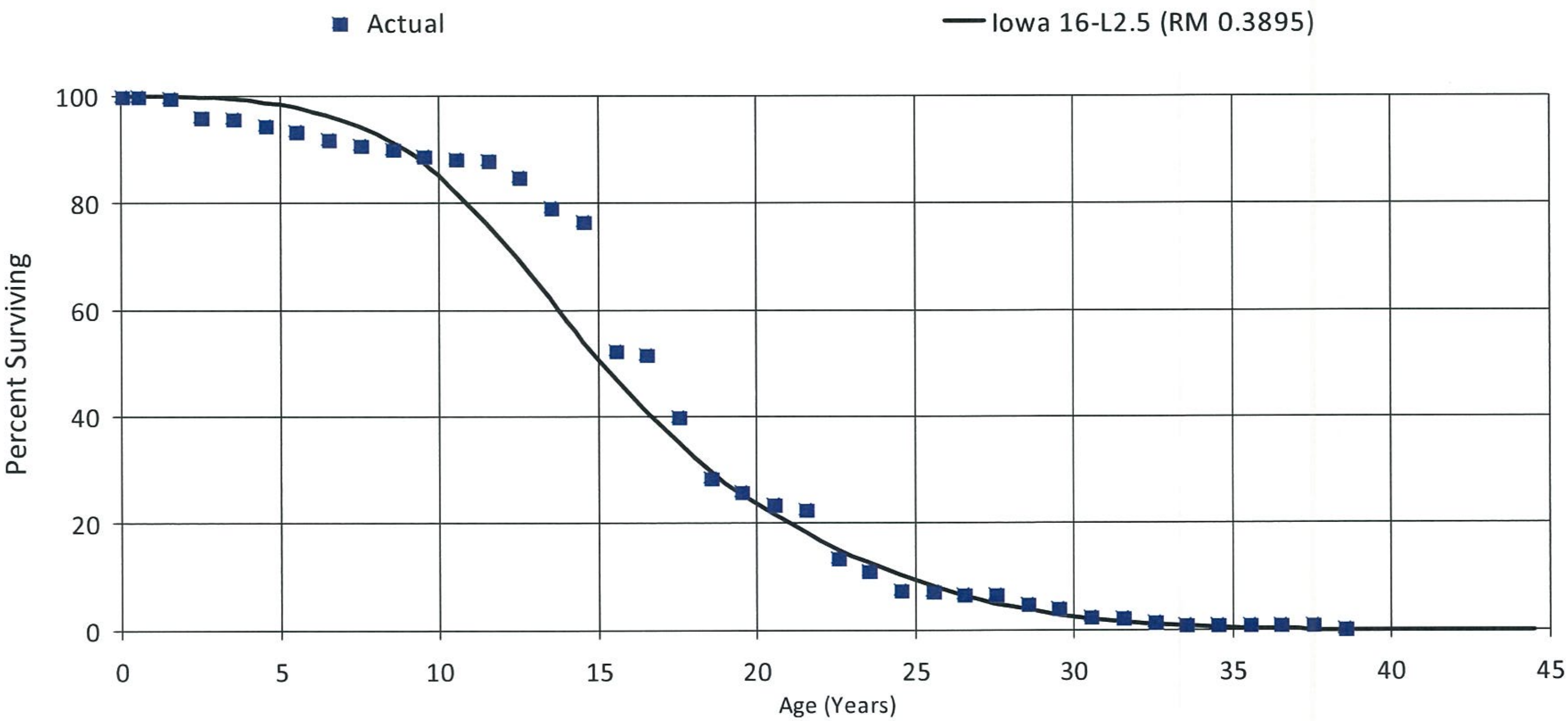
Age at Begin of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retmt Ratio	Survivor Ratio	% Surviving
0	40,190,043	0	0.0000	1.0000	100.00
0.5	38,159,504	134,594	0.0035	0.9965	100.00
1.5	36,492,142	1,297,252	0.0356	0.9645	99.65
2.5	33,229,921	76,333	0.0023	0.9977	96.11
3.5	32,228,001	494,745	0.0154	0.9847	95.89
4.5	29,522,168	306,498	0.0104	0.9896	94.42
5.5	28,154,225	489,675	0.0174	0.9826	93.44
6.5	25,987,633	266,398	0.0103	0.9898	91.82
7.5	25,291,130	237,237	0.0094	0.9906	90.88
8.5	23,465,467	290,100	0.0124	0.9876	90.03
9.5	22,488,112	158,184	0.0070	0.9930	88.92
10.5	19,093,304	77,272	0.0041	0.9960	88.29
11.5	16,700,067	573,078	0.0343	0.9657	87.93
12.5	15,454,040	1,028,118	0.0665	0.9335	84.91
13.5	14,383,797	462,730	0.0322	0.9678	79.26
14.5	13,890,302	4,409,416	0.3175	0.6826	76.71
15.5	9,198,488	110,763	0.0120	0.9880	52.36
16.5	9,087,725	2,056,740	0.2263	0.7737	51.73
17.5	7,030,985	2,009,716	0.2858	0.7142	40.02
18.5	5,021,269	479,301	0.0955	0.9046	28.58
19.5	4,541,968	397,650	0.0876	0.9125	25.85
20.5	4,144,318	195,861	0.0473	0.9527	23.59
21.5	3,918,298	1,547,761	0.3950	0.6050	22.48
22.5	2,188,962	409,061	0.1869	0.8131	13.60
23.5	1,779,901	579,467	0.3256	0.6744	11.06
24.5	1,151,047	14,980	0.0130	0.9870	7.46
25.5	1,136,067	97,507	0.0858	0.9142	7.36
26.5	1,030,410	0	0.0000	1.0000	6.73
27.5	1,030,410	273,824	0.2657	0.7343	6.73
28.5	724,976	102,374	0.1412	0.8588	4.94
29.5	622,602	253,003	0.4064	0.5936	4.24
30.5	353,755	23,880	0.0675	0.9325	2.52
31.5	329,875	118,024	0.3578	0.6422	2.35
32.5	211,851	76,985	0.3634	0.6366	1.51
33.5	134,866	0	0.0000	1.0000	0.96
34.5	134,866	0	0.0000	1.0000	0.96
35.5	134,110	0	0.0000	1.0000	0.96
36.5	134,110	0	0.0000	1.0000	0.96
37.5	55,440	43,735	0.7889	0.2111	0.96
38.5	0	0	0.0000	0.0000	0.20

Fortis BC Electrical

Account 392.20 - Heavy Duty Vehicles

Actual and Smooth Survivor Curves

Placement Band - 1972 - 2017   Experience Band - 1990 - 2017



SECTION 7

7 NET SALVAGE CALCULATIONS

FortisBC - Electricity

ACCOUNT 331.00 - GENERATION PLANT STRUCTURES AND IMPROVEMENTS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	14,776	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	10	0	0	0	-10	0	-3	0	-2	0	-2	0
2001	0	0	0	0	0	0	0	-3	0	-2	0	-1	0
2002	0	0	0	0	0	0	0	-3	0	-2	0	-1	0
2003	0	0	0	0	0	0	0	0	0	-2	0	-1	0
2004	40,943	409	1	0	0	-409	-1	-136	-1	-84	-1	-42	-1
2005	51,854	455	1	0	0	-455	-1	-288	-1	-173	-1	-80	-1
2006	3,832	45	1	0	0	-45	-1	-303	-1	-182	-1	-77	-1
2007	10,530	73	1	0	0	-73	-1	-191	-1	-197	-1	-76	-1
2008	0	372	0	0	0	-372	0	-164	-3	-271	-1	-98	-1
2009	0	34,323	0	0	0	-34,323	0	-11,589	-330	-7,054	-53	-2,379	-29
2010	1,634	11,001	673	0	0	-11,001	-673	-15,232	-2,797	-9,163	-286	-2,918	-38
2011	0	38,355	0	0	0	-38,355	0	-27,893	-5,122	-16,825	-692	-5,003	-69
2012	13,159	74,904	569	0	0	-74,904	-569	-41,420	-840	-31,791	-1,075	-8,886	-117
2013	0	0	0	0	0	0	0	-37,753	-861	-31,717	-1,072	-8,418	-117
2014	12,872	349,560	2,716	0	0	-349,560	-2,716	-141,488	-1,631	-94,764	-1,713	-25,475	-341
2015	13,016	189,502	1,456	0	0	-189,502	-1,456	-179,687	-2,082	-130,464	-1,671	-33,286	-430
2016	1,489	215,519	14,471	0	0	-215,519	-14,471	-251,527	-2,756	-165,897	-2,046	-41,570	-557
2017	249,915	435,309	174	0	0	-435,309	-174	-280,110	-318	-237,978	-429	-58,689	-326
TOTAL	**414,020**	**1,349,840**	**326**	**0**	**0**	**-1,349,840**	**-326**						

FortisBC - Electricity

ACCOUNT 332.00 - GENERATION PLANT RESERVOIRS, DAMS AND WATERWAYS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	68,452	685	1	0	0	-685	-1	-228	-1	-137	-1	-68	-1
2005	369,177	655	0	0	0	-655	0	-446	0	-268	0	-122	0
2006	3,015	806	27	0	0	-806	-27	-715	0	-429	0	-179	0
2007	76,239	1,474	2	0	0	-1,474	-2	-979	-1	-724	-1	-278	-1
2008	4,551	47	1	0	0	-47	-1	-776	-3	-733	-1	-262	-1
2009	19,693	213,012	1,082	0	0	-213,012	-1,082	-71,511	-214	-43,199	-46	-14,445	-40
2010	9,503	35,678	375	0	0	-35,678	-375	-82,913	-737	-50,204	-222	-15,772	-46
2011	0	48,265	0	0	0	-48,265	0	-98,985	-1,017	-59,695	-271	-17,684	-55
2012	73,047	85,181	117	0	0	-85,181	-117	-56,375	-205	-76,437	-358	-21,434	-62
2013	0	11,455	0	0	0	-11,455	0	-48,300	-198	-78,718	-385	-20,908	-64
2014	30,533	22,140	73	0	0	-22,140	-73	-39,592	-115	-40,544	-179	-20,970	-64
2015	764	42,048	5,505	0	0	-42,048	-5,505	-25,214	-242	-41,818	-200	-21,974	-70
2016	35,604	7,306	21	0	0	-7,306	-21	-23,831	-107	-33,626	-120	-21,307	-68
2017	12,826	212,445	1,656	0	0	-212,445	-1,656	-87,266	-532	-59,079	-371	-29,617	-97
TOTAL	**703,403**	**681,198**	**97**	**0**	**0**	**-681,198**	**-97**						

FortisBC - Electricity

ACCOUNT 333.00 - GENERATION PLANT WATERHEELS, TURBINES AND GENERATORS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	149	0	0	0	-149	0					-149	0
1996	0	0	0	0	0	0	0					-74	0
1997	0	0	0	0	0	0	0	-50	0			-50	0
1998	0	0	0	0	0	0	0	0	0			-37	0
1999	0	433	4,331,500	0	0	-433	-4,331,500	-144	-4,331,500	-116	-5,816,800	-116	-5,816,800
2000	33,568	563	2	0	0	-563	-2	-332	-3	-199	-3	-191	-3
2001	0	17	0	0	0	-17	0	-338	-3	-203	-3	-166	-3
2002	0	0	0	0	0	0	0	-193	-2	-203	-3	-145	-3
2003	362,133	5	0	0	0	-5	0	-7	0	-204	0	-130	0
2004	170,821	4,290	3	0	0	-4,290	-3	-1,432	-1	-975	-1	-546	-1
2005	0	3,442	0	0	0	-3,442	0	-2,579	-1	-1,551	-1	-809	-2
2006	1,083	138	13	0	0	-138	-13	-2,623	-5	-1,575	-1	-753	-2
2007	367,027	3,509	1	0	0	-3,509	-1	-2,363	-2	-2,277	-1	-965	-1
2008	181,067	4,722	3	0	0	-4,722	-3	-2,790	-2	-3,220	-2	-1,233	-2
2009	368,480	491,636	133	0	0	-491,636	-133	-166,623	-55	-100,689	-55	-33,927	-34
2010	261,664	572,346	219	0	0	-572,346	-219	-356,235	-132	-214,470	-91	-67,578	-62
2011	0	458,607	0	0	0	-458,607	0	-507,530	-242	-306,164	-130	-90,580	-88
2012	2,376	48,160	2,027	0	0	-48,160	-2,027	-359,704	-409	-315,094	-194	-88,223	-91
2013	0	3,593	0	0	0	-3,593	0	-170,120	-21,477	-314,869	-249	-83,769	-91
2014	1,528	0	0	0	0	0	0	-17,251	-1,326	-216,541	-408	-79,581	-91
2015	0	0	0	0	0	0	0	-1,198	-235	-102,072	-13,073	-75,791	-91
2016	0	127,000	0	0	0	-127,000	0	-42,333	-8,313	-35,751	-4,579	-78,119	-98
2017	143,044	187,807	131	96,902	68	-90,905	-64	-72,635	-152	-44,300	-153	-78,675	-96
TOTAL	**1,892,792**	**1,906,418**	**101**	**96,902**	**96,210**	**-1,809,516**	**-96**						

FortisBC - Electricity

ACCOUNT 334.00 - GENERATION PLANT ACCESSORY ELECTRICAL EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	0	440	0	0	0	-440	0	-147	0	-88	0	-88	0
2000	0	653	0	0	0	-653	0	-364	0	-219	0	-182	0
2001	0	0	0	0	0	0	0	-364	0	-219	0	-156	0
2002	0	473	0	0	0	-473	0	-375	0	-313	0	-196	0
2003	188,915	2	0	0	0	-2	0	-158	0	-314	-1	-174	-1
2004	69,020	690	1	0	0	-690	-1	-388	0	-364	-1	-226	-1
2005	70,164	2,527	4	0	0	-2,527	-4	-1,073	-1	-738	-1	-435	-1
2006	37,818	247	1	0	0	-247	-1	-1,155	-2	-788	-1	-419	-1
2007	132,922	1,073	1	0	0	-1,073	-1	-1,283	-2	-908	-1	-470	-1
2008	93,009	1,160	1	0	0	-1,160	-1	-827	-1	-1,140	-1	-519	-1
2009	194,348	209,855	108	0	0	-209,855	-108	-70,696	-50	-42,972	-41	-14,475	-28
2010	378,810	236,934	63	0	0	-236,934	-63	-149,316	-67	-89,854	-54	-28,378	-39
2011	592,930	236,004	40	0	0	-236,004	-40	-227,597	-59	-137,005	-49	-40,592	-39
2012	446,687	175,354	39	0	0	-175,354	-39	-216,097	-46	-171,861	-50	-48,078	-39
2013	685,532	36,883	5	0	0	-36,883	-5	-149,413	-26	-179,006	-39	-47,489	-31
2014	49,980	67,019	134	0	0	-67,019	-134	-93,085	-24	-150,439	-35	-48,466	-33
2015	625,646	70,394	11	0	0	-70,394	-11	-58,099	-13	-117,131	-24	-49,510	-29
2016	2,232	31,478	1,411	27,289	1,223	-4,189	-188	-47,201	-21	-70,768	-20	-47,450	-29
2017	38,305	19,243	50	0	0	-19,243	-50	-31,275	-14	-39,546	-14	-46,223	-29
TOTAL	**3,606,321**	**1,090,429**	**30**	**27,289**	**90,252**	**-1,063,140**	**-29**						

FortisBC - Electricity

ACCOUNT 335.00 - GENERATION PLANT OTHER POWER PLANT EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	57,465	598	1	0	0	-598	-1	-199	-1	-120	-1	-100	-1
2001	76,417	84	0	0	0	-84	0	-227	-1	-136	-1	-97	-1
2002	0	0	0	0	0	0	0	-227	-1	-136	-1	-85	-1
2003	0	0	0	0	0	0	0	-28	0	-136	-1	-76	-1
2004	0	0	0	0	0	0	0	0	0	-136	-1	-68	-1
2005	0	0	0	0	0	0	0	0	0	-17	0	-62	-1
2006	0	0	0	0	0	0	0	0	0	0	0	-57	-1
2007	30,528	227	1	0	0	-227	-1	-76	-1	-45	-1	-70	-1
2008	30,120	137	0	0	0	-137	0	-121	-1	-73	-1	-75	-1
2009	90,985	0	0	0	0	0	0	-121	0	-73	0	-70	0
2010	7,386	13,556	184	0	0	-13,556	-184	-4,564	-11	-2,784	-9	-913	-5
2011	0	0	0	0	0	0	0	-4,519	-14	-2,784	-9	-859	-5
2012	380,467	61,811	16	0	0	-61,811	-16	-25,122	-19	-15,101	-15	-4,245	-11
2013	0	1,830	0	0	0	-1,830	0	-21,214	-17	-15,439	-16	-4,118	-12
2014	24,016	18,186	76	0	0	-18,186	-76	-27,275	-20	-19,076	-23	-4,821	-14
2015	24,933	13,058	52	0	0	-13,058	-52	-11,024	-68	-18,977	-22	-5,214	-15
2016	9,153	6,916	76	0	0	-6,916	-76	-12,720	-66	-20,360	-23	-5,291	-16
2017	130,169	10,938	8	0	0	-10,938	-8	-10,304	-19	-10,186	-27	-5,537	-15
TOTAL	**861,638**	**127,340**	**15**	**0**	**0**	**-127,340**	**-15**						

FortisBC - Electricity

ACCOUNT 353.00 - TRANSMISSION PLANT SUBSTATION EQUIPMENT
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	7,794	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	1,886	0	0	0	-1,886	0	-629	-24			-472	-24
1999	50,703	68	0	0	0	-68	0	-651	-4	-391	-3	-391	-3
2000	0	382	0	0	0	-382	0	-779	-5	-467	-4	-389	-4
2001	0	173	0	0	0	-173	0	-208	-1	-502	-5	-358	-4
2002	0	0	0	0	0	0	0	-185	0	-502	-5	-314	-4
2003	0	0	0	0	0	0	0	-58	0	-125	-1	-279	-4
2004	0	901	0	0	0	-901	0	-300	0	-291	0	-341	-6
2005	0	795	0	0	0	-795	0	-565	0	-374	0	-382	-7
2006	496,251	2,350	0	0	0	-2,350	0	-1,349	-1	-809	-1	-546	-1
2007	75,512	3,370	4	0	0	-3,370	-4	-2,172	-1	-1,483	-1	-763	-2
2008	49,236	5,005	10	0	0	-5,005	-10	-3,575	-2	-2,484	-2	-1,066	-2
2009	21,849	242,754	1,111	0	0	-242,754	-1,111	-83,710	-171	-50,855	-40	-17,179	-37
2010	76,624	535,418	699	0	0	-535,418	-699	-261,059	-530	-157,779	-110	-49,569	-102
2011	2,067,624	317,257	15	0	0	-317,257	-15	-365,143	-51	-220,761	-48	-65,315	-39
2012	67,971	210,447	310	0	0	-210,447	-310	-354,374	-48	-262,176	-57	-73,378	-45
2013	35,196	192,463	547	0	0	-192,463	-547	-240,055	-33	-299,668	-66	-79,646	-51
2014	671,807	450,636	67	0	0	-450,636	-67	-284,515	-110	-341,244	-58	-98,195	-54
2015	0	85,660	0	1,348	0	-84,312	0	-242,470	-103	-251,023	-44	-97,534	-57
2016	108,305	4,447	4	0	0	-4,447	-4	-179,798	-69	-188,461	-107	-93,303	-55
2017	156,090	24,253	16	0	0	-24,253	-16	-37,670	-43	-151,222	-78	-90,301	-53
TOTAL	**3,884,962**	**2,078,264**	**53**	**1,348**	**2,521**	**-2,076,915**	**-53**						

FortisBC - Electricity

ACCOUNT 355.00 - TRANSMISSION PLANT POLES, TOWERS AND FIXTURES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	99,949	974	1	0	0	-974	-1					-974	-1
1996	213,287	2,079	1	0	0	-2,079	-1					-1,526	-1
1997	0	-883	0	0	0	883	0	-723	-1			-723	-1
1998	0	0	0	0	0	0	0	-399	-1			-543	-1
1999	6,579	3,462	53	0	0	-3,462	-53	-860	-39	-1,126	-2	-1,126	-2
2000	100,351	1,251	1	0	0	-1,251	-1	-1,571	-4	-1,182	-2	-1,147	-2
2001	2,512	25	1	0	0	-25	-1	-1,579	-4	-771	-4	-987	-2
2002	0	454	0	0	0	-454	0	-577	-2	-1,038	-5	-920	-2
2003	1,091,033	20	0	0	0	-20	0	-166	0	-1,042	0	-820	0
2004	223,141	15,852	7	0	0	-15,852	-7	-5,442	-1	-3,520	-1	-2,323	-1
2005	64,253	-3,428	-5	0	0	3,428	5	-4,148	-1	-2,585	-1	-1,801	-1
2006	49,637	3,571	7	0	0	-3,571	-7	-5,332	-5	-3,294	-1	-1,948	-1
2007	2,154	2,282	106	0	0	-2,282	-106	-808	-2	-3,659	-1	-1,974	-1
2008	15,154	2,508	17	0	0	-2,508	-17	-2,787	-12	-4,157	-6	-2,012	-2
2009	24,891	330,850	1,329	0	0	-330,850	-1,329	-111,880	-795	-67,156	-215	-23,934	-19
2010	3,733,262	1,293,489	35	0	0	-1,293,489	-35	-542,282	-43	-326,540	-43	-103,282	-29
2011	79,952	939,959	1,176	0	0	-939,959	-1,176	-854,766	-67	-513,818	-67	-152,498	-45
2012	90,239	280,618	311	0	0	-280,618	-311	-838,022	-64	-569,485	-72	-159,616	-50
2013	5,646	71,710	1,270	0	0	-71,710	-1,270	-430,762	-735	-583,325	-74	-154,989	-51
2014	184,887	1,679,731	909	142,550	77	-1,537,180	-831	-629,836	-673	-824,591	-101	-224,099	-75
2015	387,408	936,134	242	18,222	5	-917,913	-237	-842,268	-437	-749,476	-501	-257,137	-85
2016	329,766	418,377	127	0	0	-418,377	-127	-957,823	-319	-645,159	-323	-264,466	-87
2017	0	325,945	0	0	0	-325,945	0	-554,078	-232	-654,225	-360	-267,139	-92
TOTAL	**6,704,100**	**6,304,979**	**94**	**160,772**	**170,949**	**-6,144,207**	**-92**						

FortisBC - Electricity

ACCOUNT 356.00 - TRANSMISSION PLANT CONDUCTORS AND DEVICES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	13,192	125	1	0	0	-125	-1					-125	-1
1996	393,558	3,731	1	0	0	-3,731	-1					-1,928	-1
1997	-124,398	-122	0	0	0	122	0	-1,245	-1			-1,245	-1
1998	0	0	0	0	0	0	0	-1,203	-1			-933	-1
1999	0	3,619	0	0	0	-3,619	0	-1,166	3	-1,471	-3	-1,471	-3
2000	103,152	1,250	1	0	0	-1,250	-1	-1,623	-5	-1,696	-2	-1,434	-2
2001	6,887	69	1	0	0	-69	-1	-1,646	-4	-963	34	-1,239	-2
2002	0	0	0	0	0	0	0	-440	-1	-988	-4	-1,084	-2
2003	855,508	9	0	0	0	-9	0	-26	0	-989	-1	-965	-1
2004	211,195	4,055	2	0	0	-4,055	-2	-1,355	0	-1,077	0	-1,274	-1
2005	0	4,976	0	0	0	-4,976	0	-3,013	-1	-1,822	-1	-1,610	-1
2006	0	3,571	0	0	0	-3,571	0	-4,201	-6	-2,522	-1	-1,774	-1
2007	0	2,069	0	0	0	-2,069	0	-3,538	0	-2,936	-1	-1,796	-2
2008	0	2,508	0	0	0	-2,508	0	-2,716	0	-3,436	-8	-1,847	-2
2009	0	419,432	0	0	0	-419,432	0	-141,336	0	-86,511	0	-29,686	-31
2010	3,618,338	1,290,786	36	0	0	-1,290,786	-36	-570,909	-47	-343,673	-47	-108,505	-34
2011	79,952	924,568	1,156	0	0	-924,568	-1,156	-878,262	-71	-527,872	-71	-156,508	-52
2012	104,778	1,251,596	1,195	0	0	-1,251,596	-1,195	-1,155,650	-91	-777,778	-102	-217,347	-74
2013	6,992	36,924	528	0	0	-36,924	-528	-737,696	-1,154	-784,661	-103	-207,851	-75
2014	233,833	1,399,905	599	16,034	7	-1,383,871	-592	-890,797	-773	-977,549	-121	-266,652	-97
2015	414,623	396,656	96	0	0	-396,656	-96	-605,817	-277	-798,723	-475	-272,842	-97
2016	347,009	395,876	114	0	0	-395,876	-114	-725,468	-219	-692,985	-313	-278,435	-98
2017	0	333,945	0	0	0	-333,945	0	-375,492	-148	-509,454	-254	-280,848	-103
TOTAL	**6,264,620**	**6,475,546**	**103**	**16,034**	**15,512**	**-6,459,512**	**-103**						

FortisBC - Electricity

ACCOUNT 362.00 - DISTRIBUTION PLANT SURFACE AND MINERAL
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	3,074	30,744,800	0	0	-3,074	-30,744,800					-3,074	-30,744,800
1996	330,483	3,403	1	0	0	-3,403	-1					-3,239	-2
1997	0	0	0	0	0	0	0	-2,159	-2			-2,159	-2
1998	146,294	0	0	0	0	0	0	-1,134	-1			-1,619	-1
1999	0	0	0	0	0	0	0	0	0	-1,296	-1	-1,296	-1
2000	15,208	115	1	0	0	-115	-1	-38	0	-704	-1	-1,099	-1
2001	17,841	307	2	0	0	-307	-2	-141	-1	-84	0	-986	-1
2002	0	83	0	0	0	-83	0	-169	-2	-101	0	-873	-1
2003	383,051	4	0	0	0	-4	0	-132	0	-102	0	-776	-1
2004	161,630	1,877	1	0	0	-1,877	-1	-655	0	-477	0	-886	-1
2005	0	328	0	0	0	-328	0	-737	0	-520	0	-836	-1
2006	780,412	768	0	0	0	-768	0	-991	0	-612	0	-830	-1
2007	233,118	2,769	1	0	0	-2,769	-1	-1,288	0	-1,149	0	-979	-1
2008	73,108	1,302	2	0	0	-1,302	-2	-1,613	0	-1,409	-1	-1,002	-1
2009	2,018,319	77,851	4	0	0	-77,851	-4	-27,307	-4	-16,604	-3	-6,126	-2
2010	445,859	976,059	219	0	0	-976,059	-219	-351,738	-42	-211,750	-30	-66,746	-23
2011	1,632,523	288,635	18	0	0	-288,635	-18	-447,515	-33	-269,323	-31	-79,799	-22
2012	104,276	160,924	154	0	0	-160,924	-154	-475,206	-65	-300,954	-35	-84,306	-24
2013	230,930	131,391	57	0	0	-131,391	-57	-193,650	-30	-326,972	-37	-86,784	-25
2014	518,455	1,132,395	218	2,358	0	-1,130,037	-218	-474,117	-167	-537,409	-92	-138,946	-39
2015	363,676	231,112	64	6,472	2	-224,640	-62	-495,356	-134	-387,125	-68	-143,027	-40
2016	207,263	111,327	54	5,908	3	-105,419	-51	-486,698	-134	-350,482	-123	-141,318	-41
2017	161,801	101,958	63	0	0	-101,958	-63	-144,005	-59	-338,689	-114	-139,606	-41
TOTAL	**7,824,247**	**3,225,684**	**41**	**14,739**	**35,750**	**-3,210,946**	**-41**						

FortisBC - Electricity

ACCOUNT 364.00 - DISTRIBUTION PLANT POLES, TOWERS AND FIXTURES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	358,733	4,178	1	0	0	-4,178	-1					-4,178	-1
1996	249,180	83	0	0	0	-83	0					-2,131	-1
1997	361,979	865	0	0	0	-865	0	-1,709	-1			-1,709	-1
1998	261,380	1,154	0	0	0	-1,154	0	-701	0			-1,570	-1
1999	102,575	2,893	3	0	0	-2,893	-3	-1,637	-1	-1,835	-1	-1,835	-1
2000	105,334	3,773	4	0	0	-3,773	-4	-2,607	-2	-1,754	-1	-2,158	-1
2001	87,504	3,368	4	0	0	-3,368	-4	-3,345	-3	-2,411	-1	-2,331	-1
2002	0	5,836	0	0	0	-5,836	0	-4,326	-7	-3,405	-3	-2,769	-1
2003	0	2	0	0	0	-2	0	-3,068	-11	-3,174	-5	-2,461	-1
2004	152,450	4,070	3	0	0	-4,070	-3	-3,302	-6	-3,410	-5	-2,622	-2
2005	124,134	12	0	0	0	-12	0	-1,361	-1	-2,657	-4	-2,385	-1
2006	249,103	4	0	0	0	-4	0	-1,362	-1	-1,985	-2	-2,186	-1
2007	285,089	-70	0	0	0	70	0	18	0	-804	0	-2,013	-1
2008	354,093	-56	0	0	0	56	0	40	0	-792	0	-1,865	-1
2009	433,826	899,583	207	0	0	-899,583	-207	-299,819	-84	-179,895	-62	-61,713	-30
2010	397,516	826,460	208	0	0	-826,460	-208	-575,329	-146	-345,184	-100	-109,510	-50
2011	182,667	563,990	309	0	0	-563,990	-309	-763,344	-226	-457,981	-139	-136,244	-63
2012	461,965	427,020	92	0	0	-427,020	-92	-605,823	-174	-543,399	-148	-152,398	-66
2013	495,508	342,056	69	0	0	-342,056	-69	-444,355	-117	-611,822	-155	-162,380	-66
2014	786,935	900,638	114	853	0	-899,785	-114	-556,287	-96	-611,862	-132	-199,250	-73
2015	374,796	1,286,206	343	69,511	19	-1,216,695	-325	-819,512	-148	-689,909	-150	-247,700	-89
2016	289,315	781,922	270	4,647	2	-777,275	-269	-964,585	-199	-732,566	-152	-271,772	-98
2017	517,824	940,902	182	10,434	2	-930,468	-180	-974,813	-247	-833,256	-169	-300,411	-104
TOTAL	**6,631,906**	**6,994,888**	**105**	**85,445**	**81,011**	**-6,909,443**	**-104**						

FortisBC - Electricity

ACCOUNT 365.00 - DISTRIBUTION PLANT CONDUCTORS AND DEVICES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	825,623	1,670	0	0	0	-1,670	0					-1,670	0
1996	193,306	-3,213	-2	0	0	3,213	2					771	0
1997	336,433	5,100	2	0	0	-5,100	-2	-1,186	0			-1,186	0
1998	216,234	1,261	1	0	0	-1,261	-1	-1,050	0			-1,205	0
1999	0	2,090	0	0	0	-2,090	0	-2,817	-2	-1,382	0	-1,382	0
2000	93,238	3,744	4	0	0	-3,744	-4	-2,365	-2	-1,797	-1	-1,775	-1
2001	44,968	3,034	7	0	0	-3,034	-7	-2,956	-6	-3,046	-2	-1,955	-1
2002	0	-368	0	0	0	368	0	-2,136	-5	-1,952	-3	-1,665	-1
2003	75,543	1	0	0	0	-1	0	-889	-2	-1,700	-4	-1,480	-1
2004	113,231	5,802	5	0	0	-5,802	-5	-1,812	-3	-2,443	-4	-1,912	-1
2005	273,643	-296	0	0	0	296	0	-1,836	-1	-1,635	-2	-1,711	-1
2006	417,711	-1,269	0	0	0	1,269	0	-1,412	-1	-774	0	-1,463	-1
2007	428,815	-274	0	0	0	274	0	613	0	-793	0	-1,329	-1
2008	587,763	0	0	0	0	0	0	514	0	-793	0	-1,234	0
2009	708,815	1,393,766	197	0	0	-1,393,766	-197	-464,497	-81	-278,385	-58	-94,070	-33
2010	769,802	1,318,948	171	0	0	-1,318,948	-171	-904,238	-131	-542,234	-93	-170,625	-54
2011	300,103	903,468	301	0	0	-903,468	-301	-1,205,394	-203	-723,182	-129	-213,733	-67
2012	376,145	688,743	183	0	0	-688,743	-183	-970,386	-201	-860,985	-157	-240,123	-75
2013	386,350	398,316	103	0	0	-398,316	-103	-663,509	-187	-940,648	-185	-248,449	-77
2014	1,033,015	1,428,938	138	1,375	0	-1,427,563	-138	-838,207	-140	-947,407	-165	-307,404	-86
2015	697,034	1,962,414	282	0	0	-1,962,414	-282	-1,262,764	-179	-1,076,101	-193	-386,214	-103
2016	627,531	1,253,671	200	0	0	-1,253,671	-200	-1,547,883	-197	-1,146,141	-184	-425,644	-110
2017	757,201	1,500,757	198	0	0	-1,500,757	-198	-1,572,280	-227	-1,308,544	-187	-472,388	-117
TOTAL	**9,262,505**	**10,866,302**	**117**	**1,375**	**1,172**	**-10,864,927**	**-117**						

FortisBC - Electricity

ACCOUNT 368.00 - DISTRIBUTION PLANT - LINE TRANSFORMERS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	5,468	492	9	0	0	-492	-9					-492	-9
1996	0	-85	0	0	0	85	0					-203	-7
1997	146,975	0	0	0	0	0	0	-136	0			-136	0
1998	0	0	0	0	0	0	0	28	0			-102	0
1999	127,125	2,340	2	0	0	-2,340	-2	-780	-1	-549	-1	-549	-1
2000	0	308	0	0	0	-308	0	-883	-2	-513	-1	-509	-1
2001	227,756	2,407	1	0	0	-2,407	-1	-1,685	-1	-1,011	-1	-780	-1
2002	0	2,017	0	0	0	-2,017	0	-1,577	-2	-1,414	-2	-935	-1
2003	234,683	3	0	0	0	-3	0	-1,476	-1	-1,415	-1	-831	-1
2004	481,295	7,569	2	0	0	-7,569	-2	-3,196	-1	-2,461	-1	-1,505	-1
2005	577,784	277	0	0	0	-277	0	-2,616	-1	-2,454	-1	-1,393	-1
2006	942,950	1,308	0	0	0	-1,308	0	-3,051	0	-2,234	0	-1,386	-1
2007	1,026,299	3,020	0	0	0	-3,020	0	-1,535	0	-2,435	0	-1,512	-1
2008	1,461,654	2,048	0	0	0	-2,048	0	-2,125	0	-2,844	0	-1,550	0
2009	1,632,016	737,628	45	0	0	-737,628	-45	-247,565	-18	-148,856	-13	-50,622	-11
2010	1,384,063	712,410	51	0	0	-712,410	-51	-484,028	-32	-291,283	-23	-91,984	-18
2011	781,632	538,093	69	0	0	-538,093	-69	-662,710	-52	-398,640	-32	-118,225	-22
2012	964,590	478,654	50	0	0	-478,654	-50	-576,385	-55	-493,766	-40	-138,249	-25
2013	925,054	279,130	30	0	0	-279,130	-30	-431,959	-49	-549,183	-48	-145,664	-25
2014	1,983,414	807,074	41	523	0	-806,551	-41	-521,445	-40	-562,968	-47	-178,708	-28
2015	1,249,686	752,504	60	0	0	-752,504	-60	-612,729	-44	-570,986	-48	-206,032	-31
2016	1,149,584	476,393	41	0	0	-476,393	-41	-678,483	-46	-558,646	-45	-218,321	-31
2017	1,410,276	570,285	40	0	0	-570,285	-40	-599,727	-47	-576,973	-43	-233,624	-32
TOTAL	**16,712,304**	**5,373,872**	**32**	**523**	**1,625**	**-5,373,350**	**-32**						

FortisBC - Electricity

ACCOUNT 373.00 - DISTRIBUTION PLANT - STREET LIGHTING AND SIGNAL SYSTEMS
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	157	0	0	0	-157	0					-157	0
1996	0	0	0	0	0	0	0					-79	0
1997	0	0	0	0	0	0	0	-52	0			-52	0
1998	0	0	0	0	0	0	0	0	0			-39	0
1999	1,622	27	2	0	0	-27	-2	-9	-2	-37	-11	-37	-11
2000	417,141	113	0	0	0	-113	0	-47	0	-28	0	-50	0
2001	0	0	0	0	0	0	0	-47	0	-28	0	-43	0
2002	0	0	0	0	0	0	0	-38	0	-28	0	-37	0
2003	8,100	0	0	0	0	0	0	0	0	-28	0	-33	0
2004	26,253	660	3	0	0	-660	-3	-220	-2	-155	0	-96	0
2005	23,390	2	0	0	0	-2	0	-221	-1	-132	-1	-87	0
2006	49,475	0	0	0	0	0	0	-220	-1	-132	-1	-80	0
2007	52,676	-1	0	0	0	1	0	0	0	-132	0	-74	0
2008	46,051	1	0	0	0	-1	0	0	0	-132	0	-69	0
2009	52,739	124,577	236	0	0	-124,577	-236	-41,525	-82	-24,916	-56	-8,369	-19
2010	47,370	118,203	250	0	0	-118,203	-250	-80,927	-166	-48,556	-98	-15,234	-34
2011	23,470	80,753	344	0	0	-80,753	-344	-107,844	-262	-64,707	-146	-19,088	-43
2012	57,331	0	0	0	0	0	0	-66,319	-155	-64,707	-143	-18,027	-40
2013	59,168	0	0	0	0	0	0	-26,918	-58	-64,707	-135	-17,079	-38
2014	92,239	0	0	0	0	0	0	0	0	-39,791	-71	-16,225	-34
2015	44,885	0	0	0	0	0	0	0	0	-16,151	-29	-15,452	-32
2016	34,643	0	0	0	0	0	0	0	0	0	0	-14,750	-31
2017	62,942	0	0	0	0	0	0	0	0	0	0	-14,108	-30
TOTAL	**1,099,493**	**324,492**	**30**	**0**	**0**	**-324,492**	**-30**						

FortisBC - Electricity

ACCOUNT 390.10 - GENERAL PLANT - STRUCTURE - MASONRY
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0	1,995					16
1996	0	0	0	0	0	0	0	1,996					18
1997	0	0	0	0	0	0	0	1,997	0	0			21
1998	0	0	0	0	0	0	0	1,998	0	0			25
1999	0	0	0	0	0	0	0	1,999	0	0	0	0	32
2000	0	0	0	0	0	0	0	2,000	0	0	0	0	42
2001	0	0	0	0	0	0	0	2,001	0	0	0	0	64
2002	132,286	-127	0	0	0	127	0	2,002	42	0	25	0	127
2003	572,749	6	0	0	0	-6	0	2,003	40	0	24	0	61
2004	20,325	204	1	0	0	-204	-1	2,004	-27	0	-16	0	-27
2005	18,600	4	0	0	0	-4	0	2,005	-71	0	-17	0	-22
2006	11,835	0	0	0	0	0	0	2,006	-69	0	-17	0	-17
2007	0	489	0	0	0	-489	0	2,007	-164	-2	-141	0	-96
2008	0	2,547	0	0	0	-2,547	0	2,008	-1,012	-26	-649	-6	-446
2009	0	723	0	0	0	-723	0	2,009	-1,253	0	-753	-12	-481
2010	0	525	0	0	0	-525	0	2,010	-1,265	0	-857	-36	-486
2011	0	0	0	0	0	0	0	2,011	-416	0	-857	0	-437
2012	0	0	0	0	0	0	0	2,012	-175	0	-759	0	-397
2013	0	0	0	0	0	0	0	2,013	0	0	-250	0	-364
2014	0	0	0	0	0	0	0	2,014	0	0	-105	0	-336
2015	0	0	0	0	0	0	0	2,015	0	0	0	0	-312
2016	0	0	0	0	0	0	0	2,016	0	0	0	0	-291
2017	1,472,933	14,135	1	0	0	-14,135	-1	2,017	-4,712	-1	-2,827	-1	-1,157
TOTAL	**2,228,729**	**18,505**	**1**	**0**	**0**	**-18,505**	**-1**						

FortisBC - Electricity

ACCOUNT 392.10 - GENERAL PLANT - LIGHT DUTY VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	249,544	0	0	0	0	0	0	0	0	0	0	0	0
2011	41,862	0	0	0	0	0	0	0	0	0	0	0	0
2012	409,701	0	0	0	0	0	0	0	0	0	0	0	0
2013	443,467	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	793,922	0	0	0	0	0	0	0	0	0	0	0	0
2016	119,502	6,759	6	200,570	168	193,811	162	64,604	21	38,762	11	8,810	9
2017	49,643	4,778	10	156,794	316	152,016	306	115,276	36	69,165	25	15,036	16
TOTAL	**2,107,640**	**11,537**	**1**	**357,364**	**65,283,418**	**345,827**	**16**						

FortisBC - Electricity

ACCOUNT 392.20 - GENERAL PLANT - HEAVY DUTY VEHICLES
SUMMARY OF BOOK SALVAGE

Year	Regular Retirements	Cost of Removal Amount	Cost of Removal Percent	Gross Salvage Amount	Gross Salvage Percent	Net Salvage Amount	Net Salvage Percent	3-Year Amount	3-Year Percent	5-Year Amount	5-Year Percent	Historical Amount	Historical Percent
1995	0	0	0	0	0	0	0					0	0
1996	0	0	0	0	0	0	0					0	0
1997	0	0	0	0	0	0	0	0	0			0	0
1998	0	0	0	0	0	0	0	0	0			0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	473,310	9,685	2	102,761	22	93,076	20	31,025	20	18,615	20	5,817	20
2011	185,109	3,392	2	6,207	3	2,815	2	31,964	15	19,178	15	5,641	15
2012	371,136	5,682	2	86,477	23	80,795	22	58,895	17	35,337	17	9,816	17
2013	15,652	3,613	23	67,005	428	63,392	405	49,000	26	48,015	23	12,636	23
2014	862,544	13,659	2	329,182	38	315,523	37	153,236	37	111,120	29	27,780	29
2015	1,307,508	10,288	1	186,100	14	175,812	13	184,909	25	127,667	23	34,829	23
2016	756,231	0	0	0	0	0	0	163,779	17	127,104	19	33,246	18
2017	729,719	0	0	0	0	0	0	58,604	6	110,945	15	31,801	16
TOTAL	**4,701,208**	**46,319**	**1**	**777,731**	**78,937,541**	**731,412**	**16**						

SECTION 8

8 DETAILED DEPRECIATION CALCULATIONS

Fortis BC Electrical

Account #: 330.10 - Land Rights Generation

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1980	83,965.00	40,461	75,276	0.8965	8,689	38.86	224	37.0
1983	14,974.00	6,662	12,395	0.8277	2,579	41.63	62	34.0
2005	20,957.55	3,345	6,222	0.2969	14,735	63.03	234	12.0
2007	726,878.34	96,712	179,928	0.2475	546,950	65.02	8,412	10.0
2008	114,583.26	13,724	25,532	0.2228	89,051	66.02	1,349	9.0
TOTAL	961,358.15	160,904	299,354		662,004		10,280	

COMPOSITE ANNUAL ACCRUAL RATE	1.07%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	12.66
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	62.45

Fortis BC Electrical

Account #: 331.00 - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S1.5
ASL: 60
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	154,082.97	84,742	108,496	0.7041	60,995	30.00	2,033	35.0
1984	3,658.00	1,923	2,462	0.6732	1,561	31.32	50	33.0
1985	28,887.75	14,828	18,985	0.6572	12,792	32.00	400	32.0
1986	56,563.00	28,316	36,253	0.6409	25,967	32.69	794	31.0
1987	15,641.14	7,628	9,766	0.6244	7,439	33.40	223	30.0
1988	20,857.00	9,896	12,670	0.6075	10,273	34.12	301	29.0
1989	29,039.00	13,388	17,141	0.5903	14,802	34.85	425	28.0
1990	96,022.96	42,960	55,002	0.5728	50,623	35.60	1,422	27.0
1991	811,084.00	351,579	450,130	0.5550	442,063	36.36	12,159	26.0
1992	267,598.00	112,207	143,660	0.5368	150,698	37.13	4,059	25.0
1993	1,160,244.00	469,815	601,507	0.5184	674,761	37.91	17,798	24.0
1994	1,403,771.00	547,861	701,431	0.4997	842,717	38.71	21,769	23.0
1995	2,185,168.00	820,318	1,050,260	0.4806	1,353,425	39.52	34,244	22.0
1996	156,174.00	56,270	72,043	0.4613	99,748	40.35	2,472	21.0
1997	94,696.00	32,665	41,822	0.4416	62,344	41.18	1,514	20.0
1998	455,428.07	150,009	192,058	0.4217	308,913	42.03	7,349	19.0
1999	70,304.00	22,047	28,227	0.4015	49,107	42.89	1,145	18.0
2000	464,971.00	138,364	177,149	0.3810	334,319	43.77	7,638	17.0
2001	1,021,391.00	287,371	367,924	0.3602	755,607	44.65	16,922	16.0
2002	373,101.70	98,847	126,555	0.3392	283,857	45.55	6,232	15.0
2003	467,173.86	115,998	148,513	0.3179	365,379	46.46	7,865	14.0
2004	209,949.46	48,599	62,221	0.2964	168,723	47.37	3,562	13.0
2005	401,350.75	86,083	110,213	0.2746	331,272	48.30	6,859	12.0
2006	217,430.19	42,899	54,924	0.2526	184,249	49.24	3,742	11.0
2007	621,007.69	111,757	143,084	0.2304	540,025	50.18	10,761	10.0
2008	771,956.58	125,422	160,579	0.2080	688,573	51.14	13,465	9.0
2009	295,448.33	42,789	54,783	0.1854	270,210	52.10	5,186	8.0
2010	595,952.42	75,719	96,943	0.1627	558,604	53.07	10,526	7.0

Fortis BC Electrical

Account #: 331.00 - Structures and Improvements

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S1.5
ASL: 60
Net Salvage: -10%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2011	156,210.73	17,053	21,833	0.1398	149,999	54.05	2,775	6.0
2012	923,741.19	84,205	107,809	0.1167	908,307	55.03	16,506	5.0
2013	176,153.41	12,869	16,476	0.0935	177,292	56.02	3,165	4.0
2014	901,620.00	49,478	63,347	0.0703	928,435	57.01	16,286	3.0
2015	1,335,846.95	48,925	62,639	0.0469	1,406,792	58.00	24,254	2.0
2016	1,136,099.38	20,821	26,657	0.0235	1,223,052	59.00	20,730	1.0
2017	1,136,820.82	0	0	0.0000	1,250,502	60.00	20,842	0.0
TOTAL	18,215,444.35	4,173,654	5,343,562		14,693,427		305,471	

COMPOSITE ANNUAL ACCRUAL RATE	1.68%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	13.31
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	47.50

Fortis BC Electrical

Account #: 332.00 - Reservoirs, dams and waterways

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S2
ASL: 70
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	9,448,186.27	5,495,539	4,566,479	0.4833	7,243,754	37.43	193,540	35.0
1987	87,783.00	44,789	37,217	0.4240	72,512	41.43	1,750	30.0
1989	65,068.00	31,239	25,958	0.3989	55,377	43.11	1,284	28.0
1991	15,350.00	6,894	5,728	0.3732	13,459	44.85	300	26.0
1993	707,016.92	295,043	245,164	0.3468	638,607	46.63	13,695	24.0
1994	507,161.00	203,440	169,047	0.3333	464,904	47.54	9,780	23.0
1996	18,978.00	6,989	5,807	0.3060	17,915	49.38	363	21.0
1997	31,458.00	11,060	9,190	0.2921	30,133	50.31	599	20.0
1998	1,083,532.41	362,701	301,383	0.2781	1,053,032	51.25	20,545	19.0
2003	847,766.00	210,836	175,193	0.2067	884,514	56.07	15,774	14.0
2004	1,104,371.66	255,312	212,150	0.1921	1,168,315	57.05	20,477	13.0
2005	243,422.90	51,996	43,206	0.1775	261,073	58.04	4,498	12.0
2006	2,897,371.90	567,762	471,777	0.1628	3,149,937	59.03	53,365	11.0
2007	2,188,732.51	390,161	324,201	0.1481	2,411,714	60.02	40,184	10.0
2008	3,486,392.04	559,626	465,017	0.1334	3,892,973	61.01	63,808	9.0
2009	1,548,559.95	221,039	183,671	0.1186	1,752,029	62.01	28,256	8.0
2010	2,209,837.24	276,087	229,412	0.1038	2,532,884	63.00	40,202	7.0
2011	705,347.99	75,550	62,777	0.0890	818,908	64.00	12,795	6.0
2012	2,080,696.83	185,746	154,345	0.0742	2,446,526	65.00	37,638	5.0
2013	232,034.36	16,573	13,771	0.0593	276,272	66.00	4,186	4.0
2014	2,164,343.07	115,944	96,343	0.0445	2,609,086	67.00	38,942	3.0
2015	990,072.67	35,360	29,382	0.0297	1,208,209	68.00	17,768	2.0
2016	678,133.28	12,110	10,062	0.0148	837,604	69.00	12,139	1.0
2017	650,247.93	0	0	0.0000	812,810	70.00	11,612	0.0

Fortis BC Electrical

Account #: 332.00 - Reservoirs, dams and waterways

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S2
ASL: 70
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	33,991,863.93	9,431,794	7,837,282		34,652,548		643,500	

COMPOSITE ANNUAL ACCRUAL RATE	1.89%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	16.26
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	54.46

Fortis BC Electrical

Account #: 333.00 - Water wheels, turbines and generators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 70
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	10,021.32	8,283	8,268	0.8250	4,259	23.71	180	57.0
1963	661,927.48	524,968	523,993	0.7916	303,416	25.59	11,858	54.0
1964	834,199.00	651,988	650,778	0.7801	391,971	26.23	14,943	53.0
1965	266.36	205	205	0.7685	128	26.89	5	52.0
1969	296.00	214	213	0.7203	157	29.59	5	48.0
1971	320.00	223	222	0.6953	178	30.99	6	46.0
1977	5,452.00	3,370	3,364	0.6170	3,451	35.38	98	40.0
1982	6,197,884.23	3,404,599	3,398,278	0.5483	4,349,077	39.24	110,838	35.0
1983	26.00	14	14	0.5342	19	40.03	0	34.0
1984	76,397.00	39,799	39,725	0.5200	55,771	40.83	1,366	33.0
1985	24,262.00	12,291	12,268	0.5057	18,059	41.63	434	32.0
1986	141,673.00	69,722	69,592	0.4912	107,499	42.44	2,533	31.0
1987	23,239.00	11,098	11,077	0.4767	17,971	43.26	415	30.0
1988	20,333.00	9,412	9,394	0.4620	16,022	44.08	363	29.0
1989	124,840.00	55,941	55,838	0.4473	100,212	44.91	2,232	28.0
1990	70,198.00	30,410	30,354	0.4324	57,393	45.74	1,255	27.0
1991	264,678.00	110,695	110,490	0.4175	220,358	46.58	4,731	26.0
1992	76,763.00	30,946	30,889	0.4024	65,065	47.42	1,372	25.0
1993	74,999.00	29,096	29,042	0.3872	64,707	48.27	1,340	24.0
1994	202,347.00	75,410	75,270	0.3720	177,664	49.13	3,616	23.0
1995	263,503.00	94,150	93,975	0.3566	235,404	49.99	4,709	22.0
1996	609,784.00	208,452	208,065	0.3412	554,165	50.86	10,897	21.0
1997	242,471.00	79,115	78,968	0.3257	224,120	51.73	4,333	20.0
1998	563,945.00	175,191	174,866	0.3101	530,066	52.60	10,077	19.0
1999	175,583.00	51,784	51,688	0.2944	167,791	53.48	3,137	18.0
2000	8,983,992.00	2,507,637	2,502,981	0.2786	8,727,009	54.37	160,514	17.0
2001	1,677,510.00	441,588	440,768	0.2628	1,656,119	55.26	29,970	16.0
2002	167,941.99	41,528	41,451	0.2468	168,477	56.15	3,000	15.0

Fortis BC Electrical

Account #: 333.00 - Water wheels, turbines and generators

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 70
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	111,541.33	25,793	25,745	0.2308	113,681	57.05	1,993	14.0
2004	13,810,092.50	2,970,904	2,965,388	0.2147	14,297,228	57.95	246,704	13.0
2005	226,645.86	45,090	45,007	0.1986	238,301	58.86	4,049	12.0
2006	10,137,657.60	1,852,080	1,848,641	0.1824	10,823,431	59.77	181,087	11.0
2007	6,979,034.70	1,161,139	1,158,983	0.1661	7,564,810	60.68	124,661	10.0
2009	8,256,043.52	1,102,575	1,100,528	0.1333	9,219,526	62.52	147,462	8.0
2010	12,327,471.75	1,442,899	1,440,220	0.1168	13,969,120	63.45	220,176	7.0
2011	20,664,520.99	2,076,372	2,072,517	0.1003	23,758,134	64.37	369,069	6.0
2012	1,344,753.93	112,775	112,566	0.0837	1,568,376	65.30	24,017	5.0
2013	226,553.72	15,222	15,194	0.0671	267,999	66.24	4,046	4.0
2014	1,117,010.02	56,369	56,264	0.0504	1,339,998	67.17	19,948	3.0
2015	366,480.82	12,347	12,324	0.0336	445,777	68.11	6,545	2.0
2016	240,162.83	4,050	4,043	0.0168	296,161	69.06	4,289	1.0
2017	266,285.85	0	0	0.0000	332,857	70.00	4,755	0.0
TOTAL	97,569,106.80	19,545,748	19,509,458		102,451,926		1,743,026	

COMPOSITE ANNUAL ACCRUAL RATE	1.79%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.20
COMPOSITE AVERAGE AGE (YEARS)	12.30
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	58.78

Fortis BC Electrical

Account #: 334.00 - Accessory electrical equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	2,429,193.45	2,604,172	2,460,450	1.0129	454,583	4.27	106,569	57.0
1963	36,009.00	37,845	35,756	0.9930	7,455	4.97	1,501	54.0
1964	4,376.00	4,567	4,315	0.9861	936	5.21	180	53.0
1966	934.00	961	908	0.9717	213	5.72	37	51.0
1968	3,150.00	3,188	3,012	0.9561	768	6.27	123	49.0
1969	4,532.00	4,546	4,295	0.9478	1,143	6.56	174	48.0
1971	166,041.00	163,407	154,389	0.9298	44,861	7.20	6,235	46.0
1973	3,044.00	2,931	2,769	0.9098	883	7.90	112	44.0
1974	6,163.00	5,864	5,540	0.8989	1,855	8.28	224	43.0
1975	242.00	227	215	0.8875	76	8.69	9	42.0
1976	10,090.00	9,349	8,833	0.8754	3,275	9.11	359	41.0
1977	4,199.00	3,834	3,623	0.8627	1,416	9.56	148	40.0
1978	12,510.00	11,247	10,626	0.8494	4,386	10.03	437	39.0
1979	2,324.00	2,055	1,942	0.8355	847	10.52	80	38.0
1984	41,292.00	33,086	31,260	0.7570	18,291	13.29	1,376	33.0
1986	96,990.47	74,106	70,016	0.7219	46,372	14.53	3,191	31.0
1988	3,190.00	2,312	2,185	0.6848	1,643	15.84	104	29.0
1989	54,978.00	38,734	36,596	0.6657	29,377	16.52	1,779	28.0
1990	34,251.00	23,420	22,127	0.6460	18,974	17.21	1,103	27.0
1991	134,455.00	89,089	84,173	0.6260	77,173	17.91	4,308	26.0
1992	47,926.00	30,720	29,025	0.6056	28,486	18.63	1,529	25.0
1993	75,949.00	47,013	44,419	0.5849	46,720	19.37	2,412	24.0
1994	233.00	139	131	0.5637	148	20.11	7	23.0
1996	200,512.00	110,437	104,342	0.5204	136,272	21.64	6,297	21.0
1997	30,813.00	16,249	15,352	0.4982	21,624	22.42	964	20.0
1998	345,695.00	174,064	164,457	0.4757	250,377	23.22	10,785	19.0
1999	36,767.00	17,626	16,653	0.4529	27,467	24.02	1,143	18.0
2000	1,250,030.19	568,677	537,292	0.4298	962,744	24.84	38,765	17.0

Fortis BC Electrical

Account #: 334.00 - Accessory electrical equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 40
Net Salvage: -20%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2001	3,330,879.93	1,432,846	1,353,769	0.4064	2,643,287	25.66	103,008	16.0
2002	462,203.69	187,234	176,901	0.3827	377,744	26.50	14,256	15.0
2003	196,323.46	74,550	70,436	0.3588	165,152	27.34	6,040	14.0
2004	5,259,126.66	1,862,137	1,759,368	0.3345	4,551,584	28.20	161,418	13.0
2005	104,954.72	34,442	32,542	0.3101	93,404	29.06	3,214	12.0
2006	2,100,809.02	634,396	599,384	0.2853	1,921,586	29.93	64,194	11.0
2007	2,772,544.74	763,984	721,820	0.2603	2,605,234	30.81	84,545	10.0
2008	527,543.72	131,294	124,048	0.2351	509,004	31.70	16,055	9.0
2009	4,883,068.59	1,083,983	1,024,159	0.2097	4,835,524	32.60	148,327	8.0
2010	5,819,300.59	1,134,013	1,071,428	0.1841	5,911,733	33.50	176,447	7.0
2011	6,648,755.68	1,114,071	1,052,587	0.1583	6,925,920	34.41	201,249	6.0
2012	3,473,708.77	486,485	459,636	0.1323	3,708,815	35.33	104,971	5.0
2013	541,805.27	60,878	57,519	0.1062	592,648	36.25	16,347	4.0
2014	890,608.10	75,254	71,101	0.0798	997,629	37.18	26,830	3.0
2015	550,876.65	31,113	29,396	0.0534	631,656	38.12	16,571	2.0
2016	116,767.94	3,305	3,123	0.0267	136,999	39.06	3,508	1.0
2017	422,538.43	0	0	0.0000	507,046	40.00	12,676	0.0
TOTAL	43,137,705.07	13,189,852	12,461,915		39,303,331		1,349,607	

COMPOSITE ANNUAL ACCRUAL RATE	3.13%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.29
COMPOSITE AVERAGE AGE (YEARS)	12.25
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	29.81

Fortis BC Electrical

Account #: 335.00 - Other power plant equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 51
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	296,699.41	306,658	341,204	1.1500	0	5.16	0	57.0
1966	3,794.00	3,724	4,246	1.1191	117	7.47	16	51.0
1974	920.00	806	919	0.9990	139	12.14	11	43.0
1975	1,560.00	1,343	1,531	0.9815	263	12.82	21	42.0
1976	13,034.00	11,016	12,559	0.9636	2,430	13.52	180	41.0
1977	21,030.00	17,437	19,880	0.9453	4,305	14.23	303	40.0
1978	20,835.00	16,936	19,308	0.9267	4,652	14.95	311	39.0
1979	5.00	4	5	0.9077	1	15.69	0	38.0
1982	309,056.20	230,014	262,235	0.8485	93,180	17.99	5,178	35.0
1984	61,166.00	43,303	49,369	0.8071	20,972	19.60	1,070	33.0
1985	83,345.00	57,452	65,500	0.7859	30,347	20.43	1,485	32.0
1986	303,100.32	203,193	231,657	0.7643	116,908	21.27	5,496	31.0
1987	150,893.78	98,253	112,016	0.7424	61,511	22.12	2,780	30.0
1988	148,774.00	93,967	107,130	0.7201	63,960	22.99	2,782	29.0
1989	149,348.00	91,371	104,171	0.6975	67,580	23.87	2,831	28.0
1990	383,592.00	226,983	258,779	0.6746	182,352	24.76	7,365	27.0
1991	167,474.00	95,696	109,102	0.6515	83,493	25.66	3,254	26.0
1992	40,941.00	22,553	25,712	0.6280	21,370	26.57	804	25.0
1993	198,299.90	105,117	119,842	0.6043	108,203	27.49	3,936	24.0
1994	234,783.00	119,532	136,277	0.5804	133,724	28.42	4,705	23.0
1995	260,393.00	127,062	144,862	0.5563	154,590	29.36	5,265	22.0
1996	496,063.00	231,483	263,909	0.5320	306,563	30.31	10,116	21.0
1997	582,990.00	259,524	295,879	0.5075	374,559	31.26	11,983	20.0
1998	2,187,110.00	926,334	1,056,097	0.4829	1,459,080	32.22	45,289	19.0
2002	495,110.01	166,326	189,625	0.3830	379,751	36.10	10,519	15.0
2003	18,238,607.57	5,723,530	6,525,294	0.3578	14,449,105	37.08	389,642	14.0
2004	10,403,339.19	3,033,846	3,458,833	0.3325	8,505,007	38.07	223,421	13.0
2005	922,110.20	248,390	283,185	0.3071	777,241	39.05	19,902	12.0

Fortis BC Electrical

Account #: 335.00 - Other power plant equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 51
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2006	777,610.65	192,125	219,038	0.2817	675,214	40.04	16,862	11.0
2007	684,155.32	153,747	175,285	0.2562	611,494	41.03	14,902	10.0
2008	373,290.15	75,533	86,114	0.2307	343,170	42.03	8,166	9.0
2009	2,308,438.00	415,360	473,545	0.2051	2,181,159	43.02	50,701	8.0
2010	755,928.57	119,053	135,730	0.1796	733,588	44.02	16,667	7.0
2011	259,214.50	35,002	39,905	0.1539	258,191	45.01	5,736	6.0
2012	1,503,860.41	169,264	192,974	0.1283	1,536,465	46.01	33,395	5.0
2013	126,103.57	11,357	12,948	0.1027	132,071	47.01	2,810	4.0
2014	1,231,984.12	83,225	94,884	0.0770	1,321,898	48.00	27,537	3.0
2015	335,460.38	15,109	17,225	0.0513	368,554	49.00	7,521	2.0
2016	27,619.85	622	709	0.0257	31,054	50.00	621	1.0
2017	462,024.16	0	0	0.0000	531,328	51.00	10,418	0.0
TOTAL	45,020,063.26	13,732,249	15,647,481		36,125,592		954,002	

COMPOSITE ANNUAL ACCRUAL RATE	2.12%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	13.73
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	37.47

Fortis BC Electrical

Account #: 336.00 - Roads, railroads and bridges

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	589,100.00	269,406	233,224	0.3959	355,876	40.70	8,744	35.0
1984	24,405.00	10,554	9,136	0.3744	15,269	42.57	359	33.0
1988	12,362.00	4,720	4,086	0.3306	8,276	46.36	179	29.0
1989	33,467.00	12,351	10,692	0.3195	22,775	47.32	481	28.0
1990	124,442.00	44,329	38,375	0.3084	86,067	48.28	1,783	27.0
1991	10,933.00	3,754	3,249	0.2972	7,684	49.25	156	26.0
1992	100,650.00	33,254	28,788	0.2860	71,862	50.22	1,431	25.0
1999	147,710.00	35,287	30,548	0.2068	117,162	57.08	2,052	18.0
2003	2,238.48	417	361	0.1611	1,878	61.04	31	14.0
2004	918.03	159	137	0.1496	781	62.04	13	13.0
2006	6,819.52	998	864	0.1267	5,956	64.03	93	11.0
2008	234,389.25	28,073	24,303	0.1037	210,087	66.02	3,182	9.0
TOTAL	1,287,434.28	443,301	383,764		903,671		18,503	

COMPOSITE ANNUAL ACCRUAL RATE	1.44%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.30
COMPOSITE AVERAGE AGE (YEARS)	26.23
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	49.18

Fortis BC Electrical

Account #: 350.20 - Transmission Plant - Surface and Mineral

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	71,278.06	52,190	60,239	0.8451	11,039	20.08	550	60.0
1958	34,551.79	24,971	28,823	0.8342	5,729	20.80	275	59.0
1959	2,763.34	1,971	2,275	0.8231	489	21.52	23	58.0
1960	582.44	410	473	0.8119	110	22.24	5	57.0
1961	2,850.33	1,977	2,282	0.8005	569	22.98	25	56.0
1962	20,156.50	13,778	15,903	0.7890	4,254	23.73	179	55.0
1963	31,260.31	21,051	24,298	0.7773	6,962	24.49	284	54.0
1964	16,993.61	11,269	13,007	0.7654	3,986	25.26	158	53.0
1965	19,273.35	12,581	14,521	0.7534	4,752	26.04	182	52.0
1966	3,950.77	2,537	2,929	0.7413	1,022	26.83	38	51.0
1967	2,359.50	1,490	1,720	0.7290	640	27.63	23	50.0
1968	595.99	370	427	0.7165	169	28.44	6	49.0
1969	1,196.56	730	842	0.7039	354	29.26	12	48.0
1970	869.76	521	601	0.6911	269	30.09	9	47.0
1971	1,642.63	965	1,114	0.6782	529	30.93	17	46.0
1972	479.26	276	319	0.6652	160	31.78	5	45.0
1973	832.69	470	543	0.6520	290	32.63	9	44.0
1974	4,497.72	2,489	2,873	0.6387	1,625	33.50	49	43.0
1975	8,196.07	4,440	5,124	0.6252	3,072	34.37	89	42.0
1976	85,868.53	45,504	52,522	0.6117	33,347	35.26	946	41.0
1977	10,063.09	5,213	6,017	0.5980	4,046	36.15	112	40.0
1978	10,831.78	5,482	6,327	0.5842	4,504	37.04	122	39.0
1979	26,493.79	13,089	15,108	0.5702	11,386	37.95	300	38.0
1980	51,385.22	24,762	28,581	0.5562	22,805	38.86	587	37.0
1981	19,722.84	9,263	10,691	0.5421	9,031	39.78	227	36.0
1982	41,635.32	19,041	21,977	0.5278	19,658	40.70	483	35.0
1983	50,103.21	22,292	25,730	0.5135	24,374	41.63	585	34.0
1984	137,982.87	59,669	68,872	0.4991	69,111	42.57	1,624	33.0

Fortis BC Electrical

Account #: 350.20 - Transmission Plant - Surface and Mineral

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	104,391.94	43,833	50,593	0.4846	53,799	43.51	1,237	32.0
1986	130,939.68	53,328	61,552	0.4701	69,387	44.45	1,561	31.0
1987	80,226.62	31,657	36,539	0.4555	43,687	45.41	962	30.0
1988	96,448.17	36,829	42,509	0.4407	53,939	46.36	1,163	29.0
1989	49,216.47	18,164	20,965	0.4260	28,251	47.32	597	28.0
1990	58,928.31	20,991	24,229	0.4112	34,699	48.28	719	27.0
1991	65,498.62	22,487	25,955	0.3963	39,543	49.25	803	26.0
1992	50,101.05	16,553	19,106	0.3813	30,995	50.22	617	25.0
1993	61,506.44	19,523	22,534	0.3664	38,972	51.19	761	24.0
1994	309,831.48	94,314	108,860	0.3514	200,972	52.17	3,852	23.0
1995	50,913.71	14,834	17,122	0.3363	33,792	53.15	636	22.0
1996	316,525.13	88,084	101,669	0.3212	214,856	54.13	3,969	21.0
1997	74,245.06	19,688	22,724	0.3061	51,521	55.11	935	20.0
1998	212,930.29	53,668	61,945	0.2909	150,985	56.10	2,692	19.0
1999	78,129.38	18,665	21,543	0.2757	56,586	57.08	991	18.0
2000	225,136.61	50,817	58,654	0.2605	166,482	58.07	2,867	17.0
2001	120,078.37	25,519	29,455	0.2453	90,623	59.06	1,534	16.0
2003	289,525.31	53,876	62,185	0.2148	227,341	61.04	3,724	14.0
2004	169,460.57	29,290	33,807	0.1995	135,653	62.04	2,187	13.0
2005	1,089,610.87	173,890	200,709	0.1842	888,902	63.03	14,103	12.0
2006	71,615.33	10,479	12,095	0.1689	59,520	64.03	930	11.0
2007	1,483,559.61	197,390	227,833	0.1536	1,255,727	65.02	19,313	10.0
2008	1,114,560.16	133,491	154,079	0.1382	960,481	66.02	14,549	9.0
2009	450,433.59	47,963	55,360	0.1229	395,074	67.01	5,895	8.0
2010	437,550.01	40,773	47,062	0.1076	390,488	68.01	5,742	7.0
2011	86,283.89	6,893	7,956	0.0922	78,328	69.01	1,135	6.0
2012	44,631.51	2,971	3,430	0.0768	41,202	70.01	589	5.0
2013	12,577.56	670	773	0.0615	11,804	71.00	166	4.0

Fortis BC Electrical

Account #: 350.20 - Transmission Plant - Surface and Mineral

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	53,530.73	2,139	2,469	0.0461	51,062	72.00	709	3.0
2015	42,496.52	1,132	1,307	0.0307	41,190	73.00	564	2.0
2016	34,749.10	463	534	0.0154	34,215	74.00	462	1.0
2017	48,986.21	0	0	0.0000	48,986	75.00	653	0.0
TOTAL	8,173,035.63	1,689,173	1,949,689		6,223,347		103,540	

COMPOSITE ANNUAL ACCRUAL RATE	1.27%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	15.72
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	59.50

Fortis BC Electrical

Account #: 353.00 - Transmission Plant - Substation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 50
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	56,830.00	64,344	71,038	1.2500	0	4.71	0	57.0
1961	142.00	160	178	1.2500	0	5.02	0	56.0
1964	12.00	13	15	1.2500	0	6.06	0	53.0
1965	6,772.00	7,372	8,465	1.2500	0	6.45	0	52.0
1966	383,092.29	413,044	478,865	1.2500	0	6.87	0	51.0
1967	25,270.00	26,962	31,543	1.2482	45	7.32	6	50.0
1968	47.00	50	58	1.2342	1	7.80	0	49.0
1969	458,346.17	477,640	558,786	1.2191	14,147	8.32	1,701	48.0
1970	9,963.00	10,246	11,987	1.2032	467	8.86	53	47.0
1971	16,270.00	16,497	19,300	1.1862	1,037	9.44	110	46.0
1972	383,550.00	383,088	448,170	1.1685	31,267	10.05	3,112	45.0
1973	4,006.00	3,938	4,607	1.1500	401	10.68	38	44.0
1974	1,472.00	1,423	1,665	1.1308	175	11.34	15	43.0
1975	84,593.00	80,350	94,001	1.1112	11,741	12.01	978	42.0
1976	12,018.00	11,209	13,114	1.0912	1,909	12.69	150	41.0
1977	1,391,397.03	1,273,467	1,489,814	1.0707	249,432	13.39	18,628	40.0
1978	1,413,697.27	1,268,690	1,484,225	1.0499	282,896	14.10	20,059	39.0
1979	1,579,780.00	1,389,018	1,624,996	1.0286	349,729	14.83	23,582	38.0
1980	168,265.00	144,825	169,429	1.0069	40,902	15.57	2,627	37.0
1981	15,936.00	13,414	15,693	0.9848	4,227	16.33	259	36.0
1982	2,719,436.00	2,236,634	2,616,612	0.9622	782,683	17.10	45,767	35.0
1983	82,076.00	65,889	77,082	0.9392	25,513	17.89	1,426	34.0
1984	817,024.00	639,499	748,142	0.9157	273,138	18.69	14,613	33.0
1985	3,820,045.62	2,911,982	3,406,694	0.8918	1,368,363	19.51	70,142	32.0
1986	500,402.95	371,051	434,088	0.8675	191,416	20.34	9,411	31.0
1987	2,576,226.99	1,855,834	2,171,119	0.8428	1,049,165	21.19	49,523	30.0
1988	46,051.00	32,185	37,653	0.8176	19,911	22.04	903	29.0
1989	234,355.00	158,684	185,642	0.7921	107,302	22.92	4,682	28.0

Fortis BC Electrical

Account #: 353.00 - Transmission Plant - Substation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 50
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1990	222,574.00	145,789	170,556	0.7663	107,661	23.80	4,524	27.0
1991	796,892.00	504,135	589,782	0.7401	406,333	24.69	16,454	26.0
1992	569,210.00	347,201	406,186	0.7136	305,326	25.60	11,926	25.0
1993	1,694,981.00	995,055	1,164,103	0.6868	954,623	26.52	36,000	24.0
1994	687,569.00	387,729	453,600	0.6597	405,861	27.44	14,789	23.0
1995	1,416,953.00	765,934	896,057	0.6324	875,134	28.38	30,838	22.0
1996	3,706,520.00	1,916,221	2,241,765	0.6048	2,391,385	29.32	81,560	21.0
1997	457,406.00	225,612	263,940	0.5770	307,817	30.27	10,169	20.0
1998	809,687.00	380,012	444,571	0.5491	567,537	31.23	18,175	19.0
1999	350,200.00	155,935	182,426	0.5209	255,324	32.19	7,932	18.0
2000	612,408.00	257,874	301,684	0.4926	463,826	33.16	13,989	17.0
2001	1,480,363.00	587,368	687,155	0.4642	1,163,298	34.13	34,085	16.0
2002	43,751.97	16,291	19,059	0.4356	35,631	35.11	1,015	15.0
2003	32,837,532.82	11,422,690	13,363,271	0.4070	27,683,645	36.09	767,161	14.0
2004	9,732,940.93	3,146,366	3,680,897	0.3782	8,485,279	37.07	228,904	13.0
2005	50,098,878.52	14,960,313	17,501,895	0.3493	45,121,703	38.06	1,185,686	12.0
2006	19,011,886.45	5,207,398	6,092,073	0.3204	17,672,785	39.04	452,639	11.0
2007	9,572,790.31	2,384,945	2,790,119	0.2915	9,175,869	40.03	229,199	10.0
2008	2,220,920.31	498,220	582,861	0.2624	2,193,289	41.03	53,460	9.0
2009	2,849,461.85	568,429	664,999	0.2334	2,896,829	42.02	68,938	8.0
2010	10,145,633.44	1,771,553	2,072,519	0.2043	10,609,523	43.02	246,644	7.0
2011	41,266,033.80	6,178,057	7,227,636	0.1751	44,354,906	44.01	1,007,803	6.0
2012	6,303,160.17	786,588	920,220	0.1460	6,958,730	45.01	154,610	5.0
2013	1,666,020.09	166,361	194,624	0.1168	1,887,901	46.01	41,036	4.0
2014	9,825,290.09	735,959	860,990	0.0876	11,420,623	47.00	242,972	3.0
2015	1,733,514.52	86,576	101,284	0.0584	2,065,609	48.00	43,031	2.0
2016	1,673,424.18	41,788	48,888	0.0292	2,042,893	49.00	41,691	1.0
2017	3,453,191.06	0	0	0.0000	4,316,489	50.00	86,330	0.0

Fortis BC Electrical

Account #: 353.00 - Transmission Plant - Substation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 50
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	232,046,269.83	68,497,907	80,126,142		209,931,695		5,399,347	

COMPOSITE ANNUAL ACCRUAL RATE	2.33%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.35
COMPOSITE AVERAGE AGE (YEARS)	12.04
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	38.19

Fortis BC Electrical

Account #: 355.00 - Transmission Plant - Poles, Towers and Fixtures

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 50
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	221,478.74	227,887	277,457	1.2527	21,540	11.89	1,811	60.0
1958	174,189.95	177,468	216,071	1.2404	19,086	12.27	1,556	59.0
1959	96,274.86	97,089	118,208	1.2278	11,763	12.65	930	58.0
1960	10,535.37	10,513	12,799	1.2149	1,423	13.04	109	57.0
1961	2,985.80	2,947	3,588	1.2017	443	13.45	33	56.0
1962	176,366.21	172,103	209,538	1.1881	28,556	13.86	2,061	55.0
1963	322,157.80	310,693	378,274	1.1742	56,639	14.28	3,966	54.0
1964	148,537.39	141,515	172,297	1.1600	28,229	14.71	1,919	53.0
1965	41,543.97	39,083	47,584	1.1454	8,501	15.16	561	52.0
1966	33,944.92	31,518	38,374	1.1305	7,452	15.61	477	51.0
1967	19,325.69	17,702	21,552	1.1152	4,538	16.08	282	50.0
1968	3,689.05	3,332	4,056	1.0996	924	16.55	56	49.0
1969	5,820.97	5,181	6,308	1.0837	1,550	17.04	91	48.0
1970	3,031.16	2,657	3,235	1.0674	857	17.53	49	47.0
1971	3,752.55	3,238	3,943	1.0507	1,123	18.04	62	46.0
1972	3,819.70	3,243	3,949	1.0337	1,208	18.55	65	45.0
1973	6,245.18	5,214	6,348	1.0164	2,083	19.08	109	44.0
1974	31,396.03	25,755	31,357	0.9987	11,028	19.62	562	43.0
1975	93,790.68	75,552	91,986	0.9808	34,632	20.17	1,717	42.0
1976	971,898.45	768,275	935,390	0.9624	376,673	20.72	18,177	41.0
1977	53,854.64	41,747	50,827	0.9438	21,876	21.29	1,028	40.0
1978	95,677.71	72,677	88,485	0.9248	40,680	21.87	1,860	39.0
1979	89,060.24	66,240	80,648	0.9055	39,583	22.45	1,763	38.0
1980	563,131.32	409,775	498,909	0.8860	261,318	23.05	11,337	37.0
1981	166,776.50	118,634	144,439	0.8661	80,710	23.65	3,412	36.0
1982	423,491.13	294,220	358,218	0.8459	213,495	24.27	8,797	35.0
1983	570,543.21	386,785	470,918	0.8254	299,315	24.89	12,025	34.0
1984	1,401,034.40	925,896	1,127,296	0.8046	764,101	25.52	29,937	33.0

Fortis BC Electrical

Account #: 355.00 - Transmission Plant - Poles, Towers and Fixtures

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 50
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	992,089.40	638,486	777,369	0.7836	561,951	26.16	21,478	32.0
1986	1,404,861.44	879,535	1,070,851	0.7622	825,712	26.81	30,796	31.0
1987	495,272.29	301,291	366,828	0.7407	301,790	27.47	10,987	30.0
1988	784,777.60	463,325	564,108	0.7188	495,342	28.13	17,607	29.0
1989	330,215.38	188,962	230,065	0.6967	215,725	28.81	7,489	28.0
1990	522,878.52	289,616	352,613	0.6744	353,273	29.49	11,981	27.0
1991	472,759.70	253,087	308,138	0.6518	330,087	30.17	10,940	26.0
1992	402,942.89	208,161	253,440	0.6290	290,533	30.87	9,413	25.0
1993	464,748.92	231,297	281,609	0.6059	345,802	31.57	10,954	24.0
1994	3,563,311.72	1,705,342	2,076,286	0.5827	2,734,185	32.27	84,716	23.0
1995	566,373.73	260,143	316,729	0.5592	447,875	32.99	13,577	22.0
1996	3,635,343.63	1,599,108	1,946,945	0.5356	2,960,769	33.71	87,835	21.0
1997	837,746.19	352,090	428,677	0.5117	702,281	34.43	20,395	20.0
1998	2,398,940.79	960,857	1,169,861	0.4877	2,068,709	35.17	58,828	19.0
1999	855,161.05	325,505	396,308	0.4634	758,159	35.90	21,117	18.0
2000	2,594,515.30	935,567	1,139,071	0.4390	2,363,525	36.64	64,498	17.0
2001	1,431,105.91	487,168	593,136	0.4145	1,338,856	37.39	35,806	16.0
2002	438,617.17	140,401	170,940	0.3897	421,193	38.14	11,042	15.0
2003	8,463,226.89	2,536,015	3,087,646	0.3648	8,337,710	38.90	214,327	14.0
2004	6,981,127.86	1,948,249	2,372,030	0.3398	7,052,492	39.66	177,806	13.0
2005	5,677,730.83	1,466,940	1,786,027	0.3146	5,878,910	40.43	145,407	12.0
2006	2,760,083.55	655,608	798,215	0.2892	2,927,898	41.20	71,061	11.0
2007	8,127,196.82	1,760,092	2,142,946	0.2637	8,828,770	41.98	210,314	10.0
2008	3,070,855.07	600,281	730,853	0.2380	3,414,801	42.76	79,859	9.0
2009	4,498,334.78	783,871	954,378	0.2122	5,118,374	43.55	117,539	8.0
2010	20,375,227.14	3,115,628	3,793,336	0.1862	23,713,220	44.34	534,846	7.0
2011	2,845,486.69	374,012	455,367	0.1600	3,386,040	45.13	75,026	6.0
2012	2,234,254.45	245,417	298,799	0.1337	2,717,444	45.93	59,163	5.0

Fortis BC Electrical

Account #: 355.00 - Transmission Plant - Poles, Towers and Fixtures

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 50
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	579,886.16	51,099	62,214	0.1073	720,632	46.74	15,419	4.0
2014	8,846,707.51	586,282	713,810	0.0807	11,229,245	47.55	236,179	3.0
2015	3,204,973.82	141,976	172,859	0.0539	4,153,856	48.36	85,896	2.0
2016	3,449,165.92	76,578	93,236	0.0270	4,563,138	49.18	92,789	1.0
2017	2,114,414.52	0	0	0.0000	2,854,460	50.00	57,089	0.0
TOTAL	111,154,687.26	28,998,927	35,306,745		114,752,083		2,806,931	

COMPOSITE ANNUAL ACCRUAL RATE	2.53%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.32
COMPOSITE AVERAGE AGE (YEARS)	12.48
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	40.34

Fortis BC Electrical

Account #: 356.00 - Transmission Plant - Overhead Conductors and Devices

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 51
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	284,646.01	278,760	288,136	1.0123	81,903	12.58	6,510	60.0
1958	188,007.33	182,273	188,404	1.0021	56,005	12.97	4,319	59.0
1959	102,700.47	98,535	101,850	0.9917	31,661	13.36	2,370	58.0
1960	11,474.18	10,891	11,257	0.9811	3,659	13.76	266	57.0
1961	7,130.63	6,693	6,918	0.9702	2,352	14.18	166	56.0
1962	175,189.18	162,540	168,008	0.9590	59,738	14.60	4,091	55.0
1963	341,889.12	313,425	323,968	0.9476	120,488	15.04	8,014	54.0
1964	175,722.06	159,105	164,456	0.9359	63,982	15.48	4,133	53.0
1965	43,063.98	38,493	39,788	0.9239	16,195	15.93	1,016	52.0
1966	35,884.28	31,651	32,716	0.9117	13,934	16.40	850	51.0
1967	22,578.07	19,641	20,302	0.8992	9,050	16.87	536	50.0
1968	3,797.18	3,256	3,366	0.8864	1,570	17.36	90	49.0
1969	5,991.61	5,063	5,233	0.8734	2,556	17.85	143	48.0
1970	3,120.03	2,596	2,683	0.8600	1,373	18.36	75	47.0
1971	3,862.56	3,163	3,269	0.8465	1,752	18.87	93	46.0
1972	3,931.67	3,167	3,274	0.8326	1,838	19.40	95	45.0
1973	6,428.26	5,090	5,261	0.8185	3,095	19.94	155	44.0
1974	32,316.39	25,140	25,986	0.8041	16,026	20.48	782	43.0
1975	97,389.12	74,383	76,885	0.7895	49,721	21.04	2,364	42.0
1976	1,006,446.79	754,188	779,556	0.7746	528,825	21.60	24,480	41.0
1977	55,433.37	40,727	42,097	0.7594	29,966	22.18	1,351	40.0
1978	76,680.46	55,195	57,052	0.7440	42,633	22.76	1,873	39.0
1979	248,597.16	175,180	181,073	0.7284	142,104	23.36	6,085	38.0
1980	589,682.14	406,475	420,148	0.7125	346,439	23.96	14,460	37.0
1981	171,665.47	115,655	119,545	0.6964	103,620	24.57	4,217	36.0
1982	435,905.59	286,785	296,432	0.6800	270,245	25.19	10,728	35.0
1983	595,647.07	382,331	395,191	0.6635	379,150	25.82	14,685	34.0
1984	1,443,257.33	902,942	933,314	0.6467	942,921	26.46	35,641	33.0

Fortis BC Electrical

Account #: 356.00 - Transmission Plant - Overhead Conductors and Devices

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 51
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	1,110,061.74	676,219	698,964	0.6297	744,116	27.10	27,456	32.0
1986	1,443,598.62	855,350	884,121	0.6124	992,557	27.76	35,761	31.0
1987	552,485.18	318,040	328,738	0.5950	389,493	28.42	13,706	30.0
1988	806,421.49	450,467	465,620	0.5774	582,728	29.09	20,035	29.0
1989	339,895.51	184,005	190,195	0.5596	251,669	29.76	8,456	28.0
1990	538,206.46	281,985	291,470	0.5416	408,199	30.45	13,407	27.0
1991	491,522.48	248,873	257,244	0.5234	381,735	31.14	12,260	26.0
1992	430,049.73	210,103	217,170	0.5050	341,895	31.83	10,740	25.0
1993	509,928.32	239,977	248,049	0.4864	414,858	32.54	12,750	24.0
1994	3,689,202.45	1,669,373	1,725,526	0.4677	3,070,437	33.25	92,350	23.0
1995	614,385.26	266,791	275,765	0.4488	522,936	33.96	15,397	22.0
1996	3,780,728.16	1,572,126	1,625,008	0.4298	3,289,939	34.69	94,847	21.0
1997	870,758.44	345,924	357,560	0.4106	774,426	35.41	21,867	20.0
1998	2,553,010.07	966,487	998,997	0.3913	2,319,916	36.15	64,177	19.0
1999	953,346.35	342,950	354,486	0.3718	884,865	36.89	23,988	18.0
2000	2,662,486.68	907,285	937,804	0.3522	2,523,429	37.63	67,056	17.0
2001	1,460,606.68	469,837	485,641	0.3325	1,413,148	38.38	36,819	16.0
2002	459,522.30	138,985	143,660	0.3126	453,719	39.13	11,594	15.0
2003	8,468,839.19	2,397,667	2,478,317	0.2926	8,531,174	39.89	213,851	14.0
2004	7,223,738.19	1,904,593	1,968,657	0.2725	7,422,202	40.66	182,559	13.0
2005	4,214,035.08	1,028,559	1,063,156	0.2523	4,415,089	41.42	106,581	12.0
2006	2,553,606.24	572,983	592,257	0.2319	2,727,432	42.20	64,635	11.0
2007	5,568,549.12	1,139,136	1,177,453	0.2114	6,061,660	42.97	141,052	10.0
2008	3,067,051.68	566,276	585,324	0.1908	3,401,843	43.76	77,744	9.0
2009	4,734,616.55	779,225	805,436	0.1701	5,349,566	44.54	120,098	8.0
2010	20,375,342.07	2,942,433	3,041,408	0.1493	23,446,537	45.33	517,188	7.0
2011	2,798,083.59	347,314	358,996	0.1283	3,278,512	46.13	71,070	6.0
2012	2,235,444.73	231,868	239,667	0.1072	2,666,411	46.93	56,816	5.0

Fortis BC Electrical

Account #: 356.00 - Transmission Plant - Overhead Conductors and Devices

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1.5
ASL: 51
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2013	979,476.92	81,497	84,239	0.0860	1,189,081	47.74	24,910	4.0
2014	7,610,667.41	476,209	492,227	0.0647	9,401,640	48.55	193,667	3.0
2015	3,411,785.89	142,689	147,489	0.0432	4,287,833	49.36	86,870	2.0
2016	3,480,349.90	72,944	75,397	0.0217	4,449,058	50.18	88,666	1.0
2017	2,114,706.99	0	0	0.0000	2,749,119	51.00	53,904	0.0
TOTAL	108,270,946.98	27,371,511	28,292,205		112,460,026		2,731,870	

COMPOSITE ANNUAL ACCRUAL RATE	2.52%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.26
COMPOSITE AVERAGE AGE (YEARS)	12.82
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	41.08

Fortis BC Electrical

Account #: 359.00 - Roads and Trails

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1957	4,051.98	3,543	3,697	0.9124	355	6.29	56	60.0
1958	1,964.19	1,705	1,779	0.9060	185	6.60	28	59.0
1959	540.81	466	486	0.8992	55	6.92	8	58.0
1960	74.44	64	66	0.8922	8	7.26	1	57.0
1961	162.04	137	143	0.8848	19	7.61	2	56.0
1962	1,145.84	963	1,005	0.8771	141	7.98	18	55.0
1963	1,777.07	1,480	1,544	0.8690	233	8.36	28	54.0
1964	966.04	797	831	0.8606	135	8.77	15	53.0
1965	1,095.64	894	933	0.8518	162	9.19	18	52.0
1966	227.59	184	192	0.8426	36	9.63	4	51.0
1967	134.14	107	112	0.8330	22	10.09	2	50.0
1968	33.89	27	28	0.8230	6	10.57	1	49.0
1969	68.02	53	55	0.8126	13	11.07	1	48.0
1970	49.43	38	40	0.8018	10	11.58	1	47.0
1971	93.39	71	74	0.7906	20	12.12	2	46.0
1972	27.25	20	21	0.7790	6	12.68	0	45.0
1973	47.34	35	36	0.7671	11	13.25	1	44.0
1974	255.71	185	193	0.7548	63	13.84	5	43.0
1975	465.91	331	346	0.7421	120	14.45	8	42.0
1976	4,881.41	3,410	3,559	0.7291	1,323	15.07	88	41.0
1977	572.07	392	409	0.7157	163	15.71	10	40.0
1978	615.76	414	432	0.7020	183	16.37	11	39.0
1979	1,506.11	993	1,036	0.6880	470	17.04	28	38.0
1980	2,921.12	1,886	1,968	0.6737	953	17.72	54	37.0
1981	1,121.19	708	739	0.6592	382	18.42	21	36.0
1982	2,366.86	1,461	1,525	0.6443	842	19.13	44	35.0
1983	2,993.83	1,805	1,884	0.6292	1,110	19.86	56	34.0
1984	7,843.97	4,613	4,814	0.6138	3,029	20.59	147	33.0

Fortis BC Electrical

Account #: 359.00 - Roads and Trails

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	5,934.42	3,401	3,550	0.5981	2,385	21.34	112	32.0
1986	7,443.59	4,153	4,334	0.5823	3,109	22.10	141	31.0
1987	4,585.54	2,488	2,596	0.5662	1,989	22.88	87	30.0
1988	5,482.85	2,889	3,014	0.5498	2,468	23.66	104	29.0
1989	2,797.83	1,430	1,492	0.5332	1,306	24.45	53	28.0
1990	3,349.93	1,658	1,730	0.5164	1,620	25.26	64	27.0
1991	3,723.43	1,782	1,860	0.4994	1,864	26.07	71	26.0
1992	2,249.64	1,039	1,085	0.4822	1,165	26.90	43	25.0
1993	3,496.50	1,557	1,625	0.4648	1,871	27.73	67	24.0
1994	17,613.14	7,547	7,876	0.4472	9,737	28.58	341	23.0
1995	2,894.32	1,191	1,243	0.4294	1,652	29.43	56	22.0
1996	18,011.74	7,100	7,409	0.4113	10,603	30.29	350	21.0
1997	4,220.63	1,590	1,659	0.3932	2,561	31.16	82	20.0
1998	12,086.53	4,340	4,530	0.3748	7,557	32.04	236	19.0
1999	4,505.92	1,538	1,605	0.3562	2,901	32.93	88	18.0
2000	12,734.01	4,118	4,298	0.3375	8,436	33.83	249	17.0
2001	6,467.55	1,975	2,061	0.3186	4,407	34.73	127	16.0
2003	203,814.63	54,758	57,146	0.2804	146,669	36.57	4,011	14.0
2004	400,777.56	100,250	104,622	0.2610	296,155	37.49	7,899	13.0
2005	57,486.72	13,307	13,888	0.2416	43,599	38.43	1,135	12.0
2009	304,250.00	47,371	49,437	0.1625	254,813	42.22	6,036	8.0

Fortis BC Electrical

Account #: 359.00 - Roads and Trails

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	1,121,929.52	292,264	305,009		816,920		22,011	

COMPOSITE ANNUAL ACCRUAL RATE	1.96%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.27
COMPOSITE AVERAGE AGE (YEARS)	13.82
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	36.97

Fortis BC Electrical

Account #: 360.20 - Distribution Plant - Surface and Mineral

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	8,862.06	6,234	8,185	0.9236	677	22.24	30	57.0
1961	512.83	356	467	0.9107	46	22.98	2	56.0
1962	689.10	471	619	0.8976	71	23.73	3	55.0
1963	832.63	561	736	0.8843	96	24.49	4	54.0
1964	678.06	450	590	0.8708	88	25.26	3	53.0
1965	1,973.13	1,288	1,691	0.8571	282	26.04	11	52.0
1966	942.31	605	795	0.8433	148	26.83	6	51.0
1967	956.96	604	794	0.8293	163	27.63	6	50.0
1968	1,013.01	629	826	0.8151	187	28.44	7	49.0
1969	1,031.77	629	826	0.8008	206	29.26	7	48.0
1970	978.30	586	769	0.7862	209	30.09	7	47.0
1971	1,052.12	618	812	0.7716	240	30.93	8	46.0
1972	1,380.94	796	1,045	0.7567	336	31.78	11	45.0
1973	1,472.18	832	1,092	0.7417	380	32.63	12	44.0
1974	2,365.72	1,309	1,719	0.7266	647	33.50	19	43.0
1975	656,480.53	355,609	466,950	0.7113	189,531	34.37	5,514	42.0
1976	4,329.44	2,294	3,013	0.6958	1,317	35.26	37	41.0
1977	4,255.93	2,205	2,895	0.6803	1,361	36.15	38	40.0
1978	5,916.12	2,994	3,932	0.6646	1,984	37.04	54	39.0
1979	5,230.62	2,584	3,393	0.6487	1,837	37.95	48	38.0
1980	6,856.02	3,304	4,338	0.6328	2,518	38.86	65	37.0
1981	9,120.39	4,283	5,625	0.6167	3,496	39.78	88	36.0
1982	8,156.20	3,730	4,898	0.6005	3,258	40.70	80	35.0
1983	6,558.69	2,918	3,832	0.5842	2,727	41.63	66	34.0
1984	6,495.14	2,809	3,688	0.5678	2,807	42.57	66	33.0
1985	6,967.88	2,926	3,842	0.5514	3,126	43.51	72	32.0
1986	6,955.58	2,833	3,720	0.5348	3,236	44.45	73	31.0
1987	6,008.60	2,371	3,113	0.5181	2,895	45.41	64	30.0

Fortis BC Electrical

Account #: 360.20 - Distribution Plant - Surface and Mineral

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	7,422.32	2,834	3,722	0.5014	3,701	46.36	80	29.0
1989	8,438.39	3,114	4,089	0.4846	4,349	47.32	92	28.0
1990	10,168.89	3,622	4,757	0.4678	5,412	48.28	112	27.0
1991	10,696.00	3,672	4,822	0.4508	5,874	49.25	119	26.0
1992	9,900.16	3,271	4,295	0.4338	5,605	50.22	112	25.0
1993	12,880.28	4,088	5,369	0.4168	7,512	51.19	147	24.0
1994	17,255.09	5,253	6,897	0.3997	10,358	52.17	199	23.0
1995	17,467.66	5,089	6,683	0.3826	10,785	53.15	203	22.0
1996	12,259.58	3,412	4,480	0.3654	7,780	54.13	144	21.0
1997	18,573.59	4,925	6,467	0.3482	12,106	55.11	220	20.0
1998	11,996.28	3,024	3,970	0.3310	8,026	56.10	143	19.0
1999	13,981.55	3,340	4,386	0.3137	9,596	57.08	168	18.0
2000	15,480.63	3,494	4,588	0.2964	10,892	58.07	188	17.0
2001	15,930.29	3,386	4,446	0.2791	11,485	59.06	194	16.0
2003	1,042,250.77	193,944	254,668	0.2443	787,583	61.04	12,902	14.0
2004	811,493.91	140,260	184,175	0.2270	627,319	62.04	10,112	13.0
2005	363,509.94	58,012	76,176	0.2096	287,334	63.03	4,559	12.0
2006	995,363.15	145,646	191,248	0.1921	804,115	64.03	12,559	11.0
2007	1,702,630.22	226,538	297,466	0.1747	1,405,164	65.02	21,611	10.0
2008	508,195.45	60,867	79,924	0.1573	428,271	66.02	6,487	9.0
2009	2,113,133.73	225,008	295,458	0.1398	1,817,676	67.01	27,124	8.0
2010	1,486,282.22	138,500	181,864	0.1224	1,304,419	68.01	19,179	7.0
2011	53,244.96	4,253	5,585	0.1049	47,660	69.01	691	6.0
2012	194,831.63	12,972	17,033	0.0874	177,799	70.01	2,540	5.0
2013	110,696.29	5,897	7,743	0.0699	102,954	71.00	1,450	4.0
2014	133,416.05	5,331	6,999	0.0525	126,417	72.00	1,756	3.0
2015	536,512.92	14,291	18,765	0.0350	517,747	73.00	7,092	2.0
2016	77,664.86	1,034	1,358	0.0175	76,307	74.00	1,031	1.0

Fortis BC Electrical

Account #: 360.20 - Distribution Plant - Surface and Mineral

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	250,224.09	0	0	0.0000	250,224	75.00	3,336	0.0
TOTAL	11,319,973.16	1,691,903	2,221,637		9,098,336		140,947	

COMPOSITE ANNUAL ACCRUAL RATE	1.25%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.20
COMPOSITE AVERAGE AGE (YEARS)	11.32
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	63.79

Fortis BC Electrical

Account #: 362.00 - Distribution Plant - Substation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1962	17,041.23	18,619	18,398	1.0796	3,756	7.98	471	55.0
1963	467.00	506	500	1.0697	108	8.36	13	54.0
1964	11,474.00	12,301	12,155	1.0593	2,762	8.77	315	53.0
1965	1,763.00	1,871	1,848	1.0485	443	9.19	48	52.0
1966	32,188.45	33,785	33,384	1.0371	8,461	9.63	879	51.0
1967	1,388.00	1,440	1,423	1.0253	381	10.09	38	50.0
1968	15,529.14	15,920	15,731	1.0130	4,457	10.57	422	49.0
1969	57,999.39	58,709	58,012	1.0002	17,387	11.07	1,571	48.0
1970	20,619.68	20,595	20,350	0.9869	6,455	11.58	557	47.0
1971	48,072.00	47,344	46,782	0.9732	15,712	12.12	1,296	46.0
1972	21,961.00	21,312	21,059	0.9589	7,491	12.68	591	45.0
1973	4,711.13	4,502	4,448	0.9442	1,676	13.25	127	44.0
1974	245,819.00	231,121	228,376	0.9290	91,189	13.84	6,590	43.0
1975	208,579.54	192,814	190,524	0.9134	80,630	14.45	5,582	42.0
1976	314,750.42	285,853	282,458	0.8974	126,718	15.07	8,409	41.0
1977	485,873.57	433,179	428,034	0.8810	203,602	15.71	12,960	40.0
1978	712,889.24	623,423	616,018	0.8641	310,738	16.37	18,988	39.0
1979	87,776.87	75,231	74,337	0.8469	39,773	17.04	2,335	38.0
1980	2,343,956.76	1,967,196	1,943,829	0.8293	1,103,314	17.72	62,261	37.0
1981	646,949.56	531,209	524,899	0.8113	316,135	18.42	17,163	36.0
1982	2,853,312.37	2,290,032	2,262,831	0.7931	1,446,475	19.13	75,608	35.0
1983	2,602,238.41	2,039,487	2,015,262	0.7744	1,367,648	19.86	68,878	34.0
1984	528,157.25	403,817	399,020	0.7555	287,584	20.59	13,965	33.0
1985	1,220,191.26	909,163	898,364	0.7362	687,885	21.34	32,231	32.0
1986	2,226,494.73	1,614,915	1,595,733	0.7167	1,298,710	22.10	58,757	31.0
1987	1,820,362.89	1,283,796	1,268,547	0.6969	1,097,924	22.88	47,996	30.0
1988	935,016.21	640,374	632,767	0.6767	582,754	23.66	24,632	29.0
1989	1,743,730.72	1,158,251	1,144,493	0.6563	1,122,356	24.45	45,900	28.0

Fortis BC Electrical

Account #: 362.00 - Distribution Plant - Substation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1990	2,428,455.00	1,562,277	1,543,721	0.6357	1,613,271	25.26	63,875	27.0
1991	3,468,821.00	2,158,086	2,132,453	0.6147	2,377,014	26.07	91,173	26.0
1992	709,169.18	425,993	420,933	0.5936	500,987	26.90	18,627	25.0
1993	1,626,419.89	941,684	930,499	0.5721	1,183,847	27.73	42,690	24.0
1994	3,134,232.00	1,745,894	1,725,156	0.5504	2,349,345	28.58	82,216	23.0
1995	4,316,570.96	2,308,693	2,281,270	0.5285	3,330,272	29.43	113,163	22.0
1996	4,213,216.34	2,158,892	2,133,249	0.5063	3,343,932	30.29	110,390	21.0
1997	2,177,476.00	1,066,403	1,053,736	0.4839	1,776,982	31.16	57,021	20.0
1998	1,973,606.32	921,379	910,435	0.4613	1,655,253	32.04	51,655	19.0
1999	3,010,259.17	1,335,771	1,319,905	0.4385	2,593,432	32.93	78,749	18.0
2000	1,236,140.00	519,696	513,523	0.4154	1,093,459	33.83	32,322	17.0
2001	2,437,994.00	967,623	956,130	0.3922	2,213,263	34.73	63,719	16.0
2002	833,762.01	311,138	307,442	0.3687	776,449	35.65	21,781	15.0
2003	3,683,024.98	1,286,357	1,271,078	0.3451	3,516,855	36.57	96,177	14.0
2004	856,454.29	278,503	275,195	0.3213	838,195	37.49	22,356	13.0
2005	7,159,948.66	2,154,632	2,129,039	0.2974	7,178,894	38.43	186,825	12.0
2006	16,793,692.30	4,643,705	4,588,547	0.2732	17,243,253	39.36	438,037	11.0
2007	21,500,739.58	5,417,124	5,352,780	0.2490	22,598,182	40.31	560,615	10.0
2008	34,367,295.30	7,809,794	7,717,029	0.2245	36,960,454	41.26	895,798	9.0
2009	31,306,921.52	6,336,739	6,261,472	0.2000	34,437,526	42.22	815,763	8.0
2010	20,288,424.97	3,600,098	3,557,336	0.1753	22,817,617	43.18	528,489	7.0
2011	18,296,629.82	2,787,869	2,754,755	0.1506	21,030,864	44.14	476,463	6.0
2012	4,436,486.63	564,278	557,575	0.1257	5,209,857	45.11	115,497	5.0
2013	2,530,999.58	257,942	254,878	0.1007	3,035,421	46.08	65,872	4.0
2014	14,477,416.87	1,108,212	1,095,049	0.0756	17,725,593	47.06	376,693	3.0
2015	8,878,585.35	453,713	448,324	0.0505	11,093,837	48.03	230,955	2.0
2016	3,474,493.76	88,889	87,834	0.0253	4,429,008	49.02	90,358	1.0
2017	3,227,199.34	0	0	0.0000	4,195,359	50.00	83,907	0.0

Fortis BC Electrical

Account #: 362.00 - Distribution Plant - Substation Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -30%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	242,053,747.64	68,128,147	67,318,926		247,350,946		6,319,766	

COMPOSITE ANNUAL ACCRUAL RATE	2.61%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.28
COMPOSITE AVERAGE AGE (YEARS)	11.49
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	39.17

Fortis BC Electrical

Account #: 364.00 - Distribution Plant - Poles, Towers and Fixtures

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	263,939.81	304,613	296,172	1.1221	60,146	7.26	8,290	57.0
1961	89,234.10	102,135	99,305	1.1129	21,161	7.61	2,781	56.0
1962	124,056.47	140,756	136,856	1.1032	30,621	7.98	3,839	55.0
1963	151,637.58	170,469	165,745	1.0930	38,966	8.36	4,659	54.0
1964	117,308.34	130,597	126,978	1.0824	31,388	8.77	3,580	53.0
1965	204,882.34	225,755	219,499	1.0713	57,092	9.19	6,213	52.0
1966	161,298.36	175,810	170,939	1.0598	46,814	9.63	4,861	51.0
1967	185,068.07	199,420	193,895	1.0477	55,947	10.09	5,544	50.0
1968	181,613.94	193,350	187,992	1.0351	57,187	10.57	5,410	49.0
1969	185,092.31	194,563	189,172	1.0220	60,703	11.07	5,485	48.0
1970	168,447.84	174,715	169,874	1.0085	57,531	11.58	4,966	47.0
1971	190,958.70	195,300	189,888	0.9944	67,906	12.12	5,602	46.0
1972	247,645.51	249,568	242,653	0.9798	91,668	12.68	7,232	45.0
1973	283,716.28	281,533	273,732	0.9648	109,285	13.25	8,249	44.0
1974	435,235.35	424,950	413,175	0.9493	174,393	13.84	12,602	43.0
1975	651,625.20	625,540	608,206	0.9334	271,488	14.45	18,794	42.0
1976	812,409.05	766,199	744,968	0.9170	351,784	15.07	23,344	41.0
1977	782,150.99	724,144	704,078	0.9002	351,825	15.71	22,395	40.0
1978	1,138,765.77	1,034,154	1,005,498	0.8830	531,836	16.37	32,498	39.0
1979	1,005,680.55	895,089	870,286	0.8654	487,383	17.04	28,609	38.0
1981	1,773,444.30	1,512,178	1,470,276	0.8291	923,874	18.42	50,158	36.0
1982	1,607,895.51	1,340,110	1,302,976	0.8104	867,683	19.13	45,354	35.0
1983	1,287,530.19	1,047,904	1,018,867	0.7913	719,299	19.86	36,226	34.0
1984	1,271,880.50	1,009,852	981,870	0.7720	735,169	20.59	35,700	33.0
1985	5,807,646.62	4,493,702	4,369,183	0.7523	3,471,140	21.34	162,641	32.0
1986	1,371,063.25	1,032,704	1,004,088	0.7323	846,847	22.10	38,313	31.0
1987	1,199,042.67	878,139	853,806	0.7121	764,902	22.88	33,438	30.0
1988	1,484,828.10	1,056,041	1,026,779	0.6915	977,739	23.66	41,327	29.0

Fortis BC Electrical

Account #: 364.00 - Distribution Plant - Poles, Towers and Fixtures

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1989	1,768,397.36	1,219,814	1,186,013	0.6707	1,201,323	24.45	49,129	28.0
1990	2,064,552.42	1,379,255	1,341,036	0.6496	1,446,110	25.26	57,256	27.0
1991	2,184,448.54	1,411,300	1,372,193	0.6282	1,576,813	26.07	60,480	26.0
1992	2,043,095.69	1,274,477	1,239,161	0.6065	1,519,018	26.90	56,477	25.0
1993	2,677,978.17	1,610,164	1,565,547	0.5846	2,049,724	27.73	73,914	24.0
1994	3,404,205.94	1,969,214	1,914,648	0.5624	2,681,030	28.58	93,823	23.0
1995	3,559,701.06	1,977,112	1,922,327	0.5400	2,883,270	29.43	97,974	22.0
1996	2,442,110.95	1,299,490	1,263,482	0.5174	2,033,368	30.29	67,126	21.0
1997	3,702,226.76	1,882,875	1,830,701	0.4945	3,167,305	31.16	101,634	20.0
1998	2,569,599.90	1,245,758	1,211,238	0.4714	2,257,721	32.04	70,456	19.0
1999	2,773,401.76	1,278,002	1,242,589	0.4480	2,501,504	32.93	75,957	18.0
2000	3,094,167.96	1,350,876	1,313,444	0.4245	2,863,683	33.83	84,649	17.0
2001	4,388,162.73	1,808,617	1,758,501	0.4007	4,165,519	34.73	119,923	16.0
2002	3,024,973.98	1,172,256	1,139,773	0.3768	2,943,942	35.65	82,586	15.0
2003	5,934,354.63	2,152,389	2,092,747	0.3526	5,918,632	36.57	161,859	14.0
2004	5,510,381.79	1,860,795	1,809,233	0.3283	5,629,783	37.49	150,156	13.0
2005	8,117,797.11	2,536,832	2,466,537	0.3038	8,492,489	38.43	221,010	12.0
2006	11,698,232.51	3,359,148	3,266,067	0.2792	12,526,547	39.36	318,217	11.0
2007	10,011,704.60	2,619,472	2,546,887	0.2544	10,968,914	40.31	272,117	10.0
2008	12,524,164.64	2,955,517	2,873,620	0.2294	14,034,002	41.26	340,137	9.0
2009	11,036,555.02	2,319,794	2,255,513	0.2044	12,643,836	42.22	299,510	8.0
2010	11,210,532.51	2,065,773	2,008,531	0.1792	13,125,688	43.18	304,010	7.0
2011	8,421,658.34	1,332,568	1,295,642	0.1538	10,073,596	44.14	228,221	6.0
2012	10,562,513.24	1,395,120	1,356,462	0.1284	12,902,931	45.11	286,045	5.0
2013	5,704,112.13	603,683	586,955	0.1029	7,113,597	46.08	154,374	4.0
2014	12,532,045.37	996,195	968,590	0.0773	15,949,671	47.06	338,952	3.0
2015	9,905,176.35	525,642	511,077	0.0516	12,860,911	48.03	267,743	2.0
2016	9,019,540.36	239,626	232,986	0.0258	11,943,394	49.02	243,663	1.0

Fortis BC Electrical

Account #: 364.00 - Distribution Plant - Poles, Towers and Fixtures

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 50
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	10,715,601.51	0	0	0.0000	14,466,062	50.00	289,321	0.0
TOTAL	205,785,491.03	65,421,054	63,608,255		214,202,158		5,624,829	

COMPOSITE ANNUAL ACCRUAL RATE	2.73%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	12.70
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	38.23

Fortis BC Electrical

Account #: 365.00 - Distribution Plant - Conductors and Devices

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 55
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	1,745,577.61	1,831,243	1,975,111	1.1315	381,419	12.26	31,111	57.0
1961	171,781.13	178,378	192,392	1.1200	39,512	12.69	3,112	56.0
1962	240,092.68	246,658	266,036	1.1081	58,089	13.15	4,419	55.0
1963	291,799.31	296,434	319,722	1.0957	74,207	13.61	5,451	54.0
1964	233,212.22	234,152	252,548	1.0829	62,288	14.10	4,419	53.0
1965	395,588.48	392,344	423,168	1.0697	110,876	14.59	7,598	52.0
1966	302,462.04	296,167	319,435	1.0561	88,889	15.11	5,884	51.0
1967	340,955.96	329,434	355,315	1.0421	104,975	15.64	6,714	50.0
1968	353,393.53	336,730	363,185	1.0277	113,896	16.18	7,039	49.0
1969	359,958.85	338,045	364,603	1.0129	121,341	16.74	7,249	48.0
1970	331,077.85	306,263	330,324	0.9977	116,631	17.31	6,737	47.0
1971	367,376.45	334,546	360,830	0.9822	135,129	17.90	7,549	46.0
1972	474,891.06	425,453	458,878	0.9663	182,225	18.50	9,850	45.0
1973	522,476.08	460,217	496,373	0.9500	208,970	19.11	10,933	44.0
1974	825,318.90	714,270	770,385	0.9334	343,795	19.74	17,415	43.0
1975	1,216,466.95	1,033,702	1,114,913	0.9165	527,317	20.38	25,874	42.0
1976	1,528,000.48	1,274,016	1,374,106	0.8993	688,694	21.03	32,746	41.0
1977	1,490,905.11	1,218,846	1,314,603	0.8817	698,119	21.69	32,181	40.0
1978	2,095,406.24	1,678,400	1,810,260	0.8639	1,018,538	22.37	45,537	39.0
1979	1,841,642.91	1,444,188	1,557,649	0.8458	928,569	23.05	40,282	38.0
1981	3,224,768.14	2,417,911	2,607,870	0.8087	1,745,567	24.45	71,385	36.0
1982	2,893,476.37	2,118,697	2,285,149	0.7898	1,621,044	25.17	64,408	35.0
1983	2,345,043.41	1,675,381	1,807,004	0.7706	1,358,805	25.89	52,477	34.0
1984	2,318,477.46	1,614,603	1,741,451	0.7511	1,388,493	26.63	52,144	33.0
1985	6,171,989.01	4,185,438	4,514,259	0.7314	3,817,926	27.37	139,481	32.0
1986	2,491,789.29	1,643,691	1,772,825	0.7115	1,591,091	28.13	56,571	31.0
1987	2,179,773.94	1,397,096	1,506,857	0.6913	1,435,838	28.89	49,704	30.0
1988	2,708,956.68	1,685,023	1,817,404	0.6709	1,839,688	29.66	62,029	29.0

Fortis BC Electrical

Account #: 365.00 - Distribution Plant - Conductors and Devices

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 55
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1989	3,152,325.09	1,900,520	2,049,831	0.6503	2,205,808	30.44	72,470	28.0
1990	3,830,211.43	2,235,156	2,410,757	0.6294	2,760,028	31.23	88,391	27.0
1991	3,922,152.24	2,212,164	2,385,959	0.6083	2,908,947	32.02	90,844	26.0
1992	3,622,093.34	1,971,442	2,126,324	0.5870	2,763,502	32.83	84,188	25.0
1993	4,737,361.81	2,484,067	2,679,224	0.5656	3,716,215	33.64	110,479	24.0
1994	5,822,898.20	2,936,165	3,166,839	0.5439	4,694,073	34.46	136,231	23.0
1995	6,332,478.35	3,064,602	3,305,367	0.5220	5,243,479	35.28	148,610	22.0
1996	4,420,383.37	2,048,685	2,209,636	0.4999	3,757,881	36.12	104,044	21.0
1997	6,665,792.99	2,951,635	3,183,525	0.4776	5,815,295	36.96	157,341	20.0
1998	4,402,583.94	1,857,778	2,003,731	0.4551	3,939,757	37.81	104,203	19.0
1999	4,921,604.68	1,973,469	2,128,512	0.4325	4,515,655	38.66	116,793	18.0
2000	5,552,759.37	2,109,087	2,274,784	0.4097	5,221,441	39.53	132,103	17.0
2001	7,865,533.75	2,819,882	3,041,421	0.3867	7,577,050	40.39	187,579	16.0
2002	4,783,366.02	1,612,181	1,738,840	0.3635	4,718,705	41.27	114,341	15.0
2003	8,928,964.85	2,816,386	3,037,651	0.3402	9,016,452	42.15	213,916	14.0
2004	8,034,809.58	2,359,523	2,544,895	0.3167	8,302,098	43.04	192,911	13.0
2005	11,741,135.11	3,190,857	3,441,541	0.2931	12,408,991	43.93	282,485	12.0
2006	18,535,857.70	4,629,151	4,992,833	0.2694	20,030,575	44.83	446,858	11.0
2007	17,182,526.72	3,910,356	4,217,566	0.2455	18,978,845	45.73	415,035	10.0
2008	19,657,376.87	4,035,527	4,352,571	0.2214	22,184,887	46.64	475,701	9.0
2009	16,801,511.19	3,072,870	3,314,284	0.1973	19,367,756	47.55	407,324	8.0
2010	17,024,173.39	2,730,329	2,944,833	0.1730	20,037,801	48.47	413,440	7.0
2011	14,261,446.85	1,964,645	2,118,994	0.1486	17,133,959	49.39	346,928	6.0
2012	14,748,151.35	1,696,514	1,829,798	0.1241	18,080,206	50.31	359,351	5.0
2013	8,999,051.78	829,748	894,936	0.0994	11,253,784	51.24	219,614	4.0
2014	19,445,270.27	1,347,211	1,453,052	0.0747	24,798,062	52.18	475,264	3.0
2015	15,541,095.49	719,108	775,604	0.0499	20,204,875	53.11	380,400	2.0
2016	14,797,419.69	342,934	369,876	0.0250	19,606,640	54.06	362,711	1.0

Fortis BC Electrical

Account #: 365.00 - Distribution Plant - Conductors and Devices

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2.5
ASL: 55
Net Salvage: -35%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2017	16,931,932.50	0	0	0.0000	22,858,109	55.00	415,602	0.0
TOTAL	332,124,926.06	95,929,321	103,465,842		344,902,808		7,915,454	

COMPOSITE ANNUAL ACCRUAL RATE	2.38%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.31
COMPOSITE AVERAGE AGE (YEARS)	13.26
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	43.23

Fortis BC Electrical

Account #: 368.00 - Distribution Plant - Line Transformers

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 42
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1982	219,180.69	193,680	168,742	0.7699	105,233	12.31	8,549	35.0
1983	760,407.75	657,669	572,991	0.7535	377,519	12.94	29,175	34.0
1984	741,964.19	627,362	546,586	0.7367	380,870	13.59	28,026	33.0
1985	2,763,550.12	2,281,807	1,988,012	0.7194	1,466,426	14.26	102,855	32.0
1986	798,717.83	643,208	560,391	0.7016	438,006	14.94	29,314	31.0
1987	701,620.56	550,371	479,508	0.6834	397,518	15.64	25,412	30.0
1988	848,164.59	647,241	563,905	0.6649	496,301	16.36	30,337	29.0
1989	1,022,627.20	758,090	660,482	0.6459	617,802	17.09	36,146	28.0
1990	1,171,152.46	842,184	733,748	0.6265	730,192	17.84	40,935	27.0
1991	1,283,634.74	894,037	778,925	0.6068	825,619	18.60	44,393	26.0
1992	1,183,908.67	797,308	694,650	0.5867	785,235	19.37	40,535	25.0
1993	1,508,292.50	980,460	854,220	0.5663	1,031,145	20.16	51,152	24.0
1994	1,662,064.49	1,040,870	906,852	0.5456	1,170,729	20.96	55,861	23.0
1995	2,123,710.52	1,278,662	1,114,027	0.5246	1,540,611	21.77	70,768	22.0
1996	1,457,088.41	841,586	733,227	0.5032	1,088,133	22.59	48,162	21.0
1997	2,244,390.82	1,240,482	1,080,763	0.4815	1,724,726	23.43	73,614	20.0
1998	1,469,662.09	775,244	675,427	0.4596	1,161,650	24.28	47,852	19.0
1999	1,520,050.69	763,009	664,768	0.4373	1,235,296	25.13	49,148	18.0
2000	1,830,504.26	871,504	759,293	0.4148	1,528,837	26.00	58,795	17.0
2001	2,670,851.23	1,201,722	1,046,993	0.3920	2,291,571	26.88	85,245	16.0
2002	3,483,184.21	1,475,025	1,285,107	0.3689	3,068,873	27.77	110,505	15.0
2003	4,594,709.79	1,822,806	1,588,110	0.3456	4,155,277	28.67	144,933	14.0
2004	4,538,705.96	1,677,956	1,461,910	0.3221	4,211,473	29.58	142,385	13.0
2005	6,020,374.27	2,061,430	1,796,009	0.2983	5,729,458	30.50	187,882	12.0
2006	11,609,563.44	3,655,630	3,184,948	0.2743	11,327,007	31.42	360,503	11.0
2007	11,184,288.72	3,211,222	2,797,760	0.2502	11,182,601	32.35	345,646	10.0
2008	10,311,197.66	2,672,026	2,327,988	0.2258	10,561,009	33.29	317,215	9.0
2009	8,892,724.92	2,053,880	1,789,432	0.2012	9,326,474	34.24	272,388	8.0

Fortis BC Electrical

Account #: 368.00 - Distribution Plant - Line Transformers

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R3
ASL: 42
Net Salvage: -25%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	8,803,017.70	1,783,412	1,553,788	0.1765	9,449,984	35.19	268,519	7.0
2011	7,377,301.82	1,284,034	1,118,708	0.1516	8,102,920	36.15	224,136	6.0
2012	6,681,229.09	971,164	846,121	0.1266	7,505,415	37.12	202,215	5.0
2013	4,496,778.23	523,944	456,483	0.1015	5,164,490	38.09	135,604	4.0
2014	9,859,665.35	863,197	752,056	0.0763	11,572,526	39.06	296,288	3.0
2015	8,481,703.40	495,869	432,023	0.0509	10,170,106	40.04	254,026	2.0
2016	8,156,485.89	238,785	208,040	0.0255	9,987,567	41.02	243,502	1.0
2017	10,168,964.15	0	0	0.0000	12,711,205	42.00	302,648	0.0
TOTAL	152,641,438.41	42,676,879	37,181,994		153,619,804		4,764,668	

COMPOSITE ANNUAL ACCRUAL RATE	3.12%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.24
COMPOSITE AVERAGE AGE (YEARS)	10.02
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	32.61

Fortis BC Electrical

Account #: 369.00 - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	184,837.08	130,016	184,837	1.0000	0	22.24	0	57.0
1961	10,696.17	7,418	10,696	1.0000	0	22.98	0	56.0
1962	14,372.55	9,824	14,373	1.0000	0	23.73	0	55.0
1963	17,366.13	11,695	17,366	1.0000	0	24.49	0	54.0
1964	14,142.19	9,378	14,142	1.0000	0	25.26	0	53.0
1965	23,196.44	15,141	23,196	1.0000	0	26.04	0	52.0
1966	17,767.49	11,411	17,767	1.0000	0	26.83	0	51.0
1967	19,959.39	12,605	19,959	1.0000	0	27.63	0	50.0
1968	21,128.77	13,116	21,129	1.0000	0	28.44	0	49.0
1969	21,519.60	13,123	21,520	1.0000	0	29.26	0	48.0
1970	20,404.53	12,218	20,405	1.0000	0	30.09	0	47.0
1971	21,944.07	12,894	21,944	1.0000	0	30.93	0	46.0
1972	28,802.58	16,599	28,803	1.0000	0	31.78	0	45.0
1973	30,705.30	17,344	30,705	1.0000	0	32.63	0	44.0
1974	49,342.16	27,303	49,342	1.0000	0	33.50	0	43.0
1975	73,540.83	39,836	73,541	1.0000	0	34.37	0	42.0
1976	90,299.70	47,852	90,300	1.0000	0	35.26	0	41.0
1977	88,766.42	45,986	88,766	1.0000	0	36.15	0	40.0
1978	123,393.52	62,450	123,394	1.0000	0	37.04	0	39.0
1979	109,095.19	53,897	109,095	1.0000	0	37.95	0	38.0
1980	142,996.75	68,908	142,997	1.0000	0	38.86	0	37.0
1981	190,225.29	89,339	190,225	1.0000	0	39.78	0	36.0
1982	170,114.73	77,797	170,115	1.0000	0	40.70	0	35.0
1983	137,693.18	61,262	137,693	1.0000	0	41.63	0	34.0
1984	137,091.67	59,284	135,329	0.9871	1,763	42.57	41	33.0
1985	1,360,610.28	571,301	1,304,120	0.9585	56,491	43.51	1,298	32.0
1986	154,723.04	63,014	143,843	0.9297	10,880	44.45	245	31.0
1987	139,243.02	54,944	125,423	0.9007	13,820	45.41	304	30.0

Fortis BC Electrical

Account #: 369.00 - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	184,723.14	70,537	161,016	0.8717	23,707	46.36	511	29.0
1989	234,370.58	86,497	197,448	0.8425	36,923	47.32	780	28.0
1990	246,978.64	87,979	200,831	0.8131	46,148	48.28	956	27.0
1991	242,049.47	83,102	189,698	0.7837	52,352	49.25	1,063	26.0
1992	237,839.34	78,580	179,376	0.7542	58,463	50.22	1,164	25.0
1993	269,743.23	85,622	195,450	0.7246	74,293	51.19	1,451	24.0
1994	383,595.55	116,768	266,549	0.6949	117,046	52.17	2,244	23.0
1995	398,622.09	116,142	265,120	0.6651	133,502	53.15	2,512	22.0
1996	267,875.31	74,545	170,166	0.6352	97,709	54.13	1,805	21.0
1997	394,170.57	104,525	238,601	0.6053	155,569	55.11	2,823	20.0
1998	316,473.98	79,766	182,083	0.5753	134,391	56.10	2,396	19.0
1999	305,653.95	73,019	166,681	0.5453	138,973	57.08	2,435	18.0
2000	342,536.90	77,316	176,491	0.5152	166,046	58.07	2,859	17.0
2001	510,441.16	108,479	247,628	0.4851	262,813	59.06	4,450	16.0
2002	17,902.39	3,568	8,145	0.4550	9,757	60.05	162	15.0
2003	57,808.58	10,757	24,556	0.4248	33,253	61.04	545	14.0
2004	104,333.96	18,033	41,165	0.3945	63,169	62.04	1,018	13.0
2005	208,367.82	33,253	75,908	0.3643	132,460	63.03	2,102	12.0
2006	182,695.99	26,733	61,024	0.3340	121,672	64.03	1,900	11.0
2007	140,960.30	18,755	42,812	0.3037	98,148	65.02	1,509	10.0
2008	181,367.53	21,722	49,586	0.2734	131,781	66.02	1,996	9.0
2009	205,182.31	21,848	49,873	0.2431	155,309	67.01	2,318	8.0
2010	6,647.25	619	1,414	0.2127	5,233	68.01	77	7.0
2011	378,758.20	30,257	69,068	0.1824	309,690	69.01	4,488	6.0
2012	288,754.86	19,225	43,885	0.1520	244,870	70.01	3,498	5.0

Fortis BC Electrical

Account #: 369.00 - Services

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 75
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	9,521,831.17	3,063,602	6,635,598		2,886,233		48,950	

COMPOSITE ANNUAL ACCRUAL RATE	0.51%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.70
COMPOSITE AVERAGE AGE (YEARS)	24.57
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	50.87

Fortis BC Electrical

Account #: 370.10 - AMI Meters

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 18
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	8,137,057.23	1,356,176	41,075	0.0050	8,095,982	15.00	539,732	3.0
2015	23,990,200.36	2,665,578	80,734	0.0034	23,909,466	16.00	1,494,342	2.0
2016	3,738,324.42	207,685	6,290	0.0017	3,732,034	17.00	219,531	1.0
2017	1,595,316.21	0	0	0.0000	1,595,316	18.00	88,629	0.0
TOTAL	37,460,898.22	4,229,439	128,100		37,332,799		2,342,234	

COMPOSITE ANNUAL ACCRUAL RATE	6.25%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.00
COMPOSITE AVERAGE AGE (YEARS)	2.03
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	15.97

Fortis BC Electrical

Account #: 371.00 - Installations on Customers' Premises

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1960	28,485.17	28,485	28,485	1.0000	0	0.00	0	57.0
1961	1,648.38	1,648	1,648	1.0000	0	0.00	0	56.0
1962	2,214.95	2,215	2,215	1.0000	0	0.00	0	55.0
1963	2,676.30	2,676	2,676	1.0000	0	0.00	0	54.0
1964	2,179.46	2,179	2,179	1.0000	0	0.00	0	53.0
1965	3,574.80	3,575	3,575	1.0000	0	0.00	0	52.0
1966	2,738.13	2,738	2,738	1.0000	0	0.00	0	51.0
1967	3,075.94	3,076	3,076	1.0000	0	0.00	0	50.0
1968	3,256.14	3,256	3,256	1.0000	0	0.00	0	49.0
1969	3,316.39	3,316	3,316	1.0000	0	0.00	0	48.0
1970	3,144.54	3,145	3,145	1.0000	0	0.00	0	47.0
1971	3,381.79	3,382	3,382	1.0000	0	0.00	0	46.0
1972	4,438.76	4,439	4,439	1.0000	0	0.00	0	45.0
1973	4,731.98	4,732	4,732	1.0000	0	0.00	0	44.0
1974	7,604.10	7,604	7,604	1.0000	0	0.00	0	43.0
1975	11,333.36	11,333	11,333	1.0000	0	0.00	0	42.0
1976	13,916.05	13,916	13,916	1.0000	0	0.00	0	41.0
1977	13,679.76	13,338	13,680	1.0000	0	0.50	0	40.0
1978	19,016.12	18,517	19,016	1.0000	0	0.53	0	39.0
1979	16,812.63	16,139	16,813	1.0000	0	0.80	0	38.0
1980	22,037.17	20,808	22,037	1.0000	0	1.12	0	37.0
1981	29,315.57	27,239	29,316	1.0000	0	1.42	0	36.0
1982	26,216.31	23,979	26,216	1.0000	0	1.71	0	35.0
1983	21,081.57	18,974	21,082	1.0000	0	2.00	0	34.0
1984	20,877.21	18,477	20,877	1.0000	0	2.30	0	33.0
1985	22,396.78	19,474	22,397	1.0000	0	2.61	0	32.0
1986	22,357.19	19,080	22,357	1.0000	0	2.93	0	31.0
1987	19,313.38	16,160	19,313	1.0000	0	3.27	0	30.0

Fortis BC Electrical

Account #: 371.00 - Installations on Customers' Premises

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R1
ASL: 20
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1988	23,857.41	19,550	23,857	1.0000	0	3.61	0	29.0
1989	27,123.37	21,740	27,123	1.0000	0	3.97	0	28.0
1990	32,685.71	25,591	32,686	1.0000	0	4.34	0	27.0
1991	34,379.96	26,255	34,380	1.0000	0	4.73	0	26.0
1992	31,822.00	23,666	31,822	1.0000	0	5.13	0	25.0
1993	41,400.92	29,934	41,401	1.0000	0	5.54	0	24.0
1994	55,462.75	38,911	55,463	1.0000	0	5.97	0	23.0
1995	56,146.06	38,143	56,146	1.0000	0	6.41	0	22.0
1996	39,405.77	25,863	39,406	1.0000	0	6.87	0	21.0
1997	59,700.84	37,759	59,701	1.0000	0	7.35	0	20.0
1998	38,559.48	23,435	38,559	1.0000	0	7.84	0	19.0
1999	44,940.77	26,164	44,941	1.0000	0	8.36	0	18.0
2000	49,759.21	27,654	49,759	1.0000	0	8.88	0	17.0
2001	67,768.14	35,811	67,768	1.0000	0	9.43	0	16.0
TOTAL	937,832.32	714,377	937,832		0		0	

COMPOSITE ANNUAL ACCRUAL RATE	0.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	1.00
COMPOSITE AVERAGE AGE (YEARS)	27.84
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.77

Fortis BC Electrical

Account #: 373.00 - Street Lighting and Signal Systems

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 25
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1985	145,773.01	139,848	122,311	0.8390	45,328	4.14	10,937	32.0
1991	29,072.52	24,796	21,687	0.7459	11,747	6.46	1,819	26.0
1992	35,138.10	29,221	25,557	0.7273	14,852	6.92	2,146	25.0
1993	46,021.58	37,241	32,571	0.7077	20,354	7.41	2,747	24.0
1994	46,621.81	36,631	32,037	0.6872	21,578	7.92	2,725	23.0
1995	61,966.15	47,163	41,249	0.6657	30,012	8.45	3,550	22.0
1996	35,060.34	25,785	22,551	0.6432	17,768	9.01	1,972	21.0
1997	66,815.33	47,353	41,415	0.6198	35,423	9.59	3,693	20.0
1998	40,448.19	27,544	24,090	0.5956	22,426	10.20	2,199	19.0
1999	39,920.03	26,037	22,771	0.5704	23,137	10.82	2,138	18.0
2000	53,707.31	33,433	29,240	0.5444	32,523	11.47	2,836	17.0
2001	81,610.03	48,301	42,244	0.5176	51,608	12.13	4,253	16.0
2003	948,133.41	500,522	437,754	0.4617	652,599	13.52	48,255	14.0
2004	871,799.85	431,248	377,167	0.4326	625,403	14.25	43,899	13.0
2005	1,072,269.52	493,915	431,975	0.4029	801,135	14.99	53,457	12.0
2006	1,585,620.78	675,186	590,514	0.3724	1,232,950	15.74	78,317	11.0
2007	1,672,006.36	652,535	570,703	0.3413	1,352,104	16.52	81,867	10.0
2008	1,734,135.18	613,902	536,916	0.3096	1,457,340	17.30	84,219	9.0
2009	1,343,979.79	426,130	372,691	0.2773	1,172,886	18.11	64,774	8.0
2010	1,261,334.16	352,495	308,291	0.2444	1,142,244	18.92	60,357	7.0
2011	693,189.91	167,216	146,246	0.2110	650,923	19.76	32,948	6.0
2012	21,613.49	4,374	3,826	0.1770	21,030	20.60	1,021	5.0
2013	10,776.15	1,756	1,536	0.1425	10,857	21.46	506	4.0
2014	91,766.14	11,286	9,870	0.1076	95,661	22.33	4,285	3.0
2015	115,676.67	9,541	8,344	0.0721	124,684	23.21	5,373	2.0
2016	198,598.76	8,236	7,203	0.0363	221,186	24.10	9,178	1.0
2017	273,468.46	0	0	0.0000	314,489	25.00	12,580	0.0

Fortis BC Electrical

Account #: 373.00 - Street Lighting and Signal Systems

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R2
ASL: 25
Net Salvage: -15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	12,576,523.03	4,871,696	4,260,758		10,202,243		622,052	

COMPOSITE ANNUAL ACCRUAL RATE	4.95%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.34
COMPOSITE AVERAGE AGE (YEARS)	10.13
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	16.58

Fortis BC Electrical

Account #: 390.10 - Structures - Masonry

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S1
ASL: 35
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1975	15,431.00	12,261	16,203	1.0500	0	8.51	0	42.0
1976	22,088.00	17,306	23,192	1.0500	0	8.88	0	41.0
1977	7,431.00	5,739	7,803	1.0500	0	9.26	0	40.0
1979	526,434.00	394,385	552,756	1.0500	0	10.03	0	38.0
1980	1,580.00	1,165	1,659	1.0500	0	10.42	0	37.0
1981	2,222.00	1,611	2,333	1.0500	0	10.83	0	36.0
1982	17,777.00	12,671	18,666	1.0500	0	11.24	0	35.0
1983	110,489.00	77,357	116,013	1.0500	0	11.66	0	34.0
1984	23,966.00	16,470	25,164	1.0500	0	12.09	0	33.0
1985	1,248,628.11	841,624	1,311,060	1.0500	0	12.53	0	32.0
1986	2,196.00	1,451	2,306	1.0500	0	12.98	0	31.0
1987	234,796.75	151,856	246,537	1.0500	0	13.44	0	30.0
1988	639,618.92	404,642	671,600	1.0500	0	13.91	0	29.0
1989	399,009.00	246,653	418,959	1.0500	0	14.39	0	28.0
1990	19,091.00	11,518	20,046	1.0500	0	14.89	0	27.0
1991	290,971.00	171,128	299,896	1.0307	5,624	15.40	365	26.0
1992	51,428.00	29,444	51,599	1.0033	2,400	15.92	151	25.0
1993	48,720.00	27,113	47,515	0.9753	3,641	16.45	221	24.0
1994	371,888.00	200,846	351,975	0.9465	38,507	17.00	2,265	23.0
1995	44,422.00	23,241	40,728	0.9168	5,915	17.56	337	22.0
1996	28,853.00	14,594	25,575	0.8864	4,720	18.14	260	21.0
1997	94,194.00	45,960	80,543	0.8551	18,360	18.74	980	20.0
1998	67,476.00	31,683	55,522	0.8228	15,327	19.35	792	19.0
1999	326,420.00	147,087	257,763	0.7897	84,978	19.98	4,253	18.0
2000	15,116.00	6,517	11,420	0.7555	4,452	20.63	216	17.0
2001	355,390.00	146,075	255,990	0.7203	117,169	21.30	5,501	16.0
2002	105,328.54	41,114	72,050	0.6840	38,545	21.99	1,753	15.0
2003	220,805.72	81,481	142,791	0.6467	89,055	22.70	3,923	14.0

Fortis BC Electrical

Account #: 390.10 - Structures - Masonry

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: S1
ASL: 35
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2004	103,373.33	35,873	62,866	0.6081	45,676	23.43	1,949	13.0
2005	52,794.20	17,125	30,010	0.5684	25,424	24.19	1,051	12.0
2006	179,764.29	54,112	94,829	0.5275	93,923	24.97	3,762	11.0
2007	583,120.07	161,504	283,029	0.4854	329,247	25.77	12,777	10.0
2008	428,079.96	107,962	189,199	0.4420	260,285	26.59	9,788	9.0
2009	405,228.74	91,873	161,003	0.3973	264,487	27.44	9,638	8.0
2010	238,355.84	47,795	83,760	0.3514	166,514	28.32	5,881	7.0
2011	337,122.31	58,527	102,567	0.3042	251,412	29.21	8,606	6.0
2012	153,028.06	22,345	39,158	0.2559	121,521	30.13	4,033	5.0
2013	16,473,970.69	1,940,432	3,400,528	0.2064	13,897,141	31.07	447,231	4.0
2014	663,066.75	58,996	103,389	0.1559	592,831	32.03	18,506	3.0
2015	330,352.49	19,709	34,539	0.1046	312,332	33.01	9,461	2.0
2016	1,794,747.00	53,754	94,201	0.0525	1,790,283	34.00	52,653	1.0
2017	16,456,914.16	35	61	0.0000	17,279,698	35.00	493,707	0.0
TOTAL	43,491,687.93	5,833,034	9,806,806		35,859,466		1,100,061	

COMPOSITE ANNUAL ACCRUAL RATE	2.53%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.23
COMPOSITE AVERAGE AGE (YEARS)	5.43
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	30.53

Fortis BC Electrical

Account #: 390.20 - Operations Building

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: R4
ASL: 50
Net Salvage: -5%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1986	44,990.00	28,023	47,240	1.0500	0	20.34	0	31.0
1987	8,110.00	4,907	8,516	1.0500	0	21.19	0	30.0
1988	308.00	181	314	1.0211	9	22.04	0	29.0
1993	291,363.00	143,680	249,895	0.8577	56,036	26.52	2,113	24.0
1994	24,650.00	11,676	20,308	0.8239	5,574	27.44	203	23.0
2002	2,848,524.94	890,968	1,549,617	0.5440	1,441,334	35.11	41,057	15.0
2003	4,809,576.43	1,405,348	2,444,253	0.5082	2,605,802	36.09	72,211	14.0
2005	178,311.07	44,727	77,792	0.4363	109,435	38.06	2,876	12.0
2006	585,498.10	134,710	234,295	0.4002	380,478	39.04	9,745	11.0
2007	543,028.60	113,643	197,653	0.3640	372,527	40.03	9,305	10.0
2008	383,366.66	72,241	125,645	0.3277	276,890	41.03	6,749	9.0
2009	734,960.51	123,156	214,200	0.2914	557,509	42.02	13,268	8.0
2010	261,026.71	38,286	66,589	0.2551	207,489	43.02	4,824	7.0
2011	615,836.39	77,447	134,700	0.2187	511,929	44.01	11,632	6.0
2012	1,308,284.26	137,142	238,524	0.1823	1,135,174	45.01	25,221	5.0
2013	665,679.56	55,836	97,113	0.1459	601,850	46.01	13,082	4.0
2014	413,958.50	26,046	45,301	0.1094	389,356	47.00	8,283	3.0
2015	341,627.53	14,332	24,927	0.0730	333,782	48.00	6,953	2.0
2016	76,975.55	1,615	2,808	0.0365	78,016	49.00	1,592	1.0
2017	366,817.46	0	0	0.0000	385,158	50.00	7,703	0.0
TOTAL	14,502,893.27	3,323,964	5,779,689		9,448,349		236,818	

COMPOSITE ANNUAL ACCRUAL RATE	1.63%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.40
COMPOSITE AVERAGE AGE (YEARS)	10.99
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	39.09

Fortis BC Electrical

Account #: 391.00 - Office Furniture and Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	451,130.69	421,055	451,131	1.0000	0	1.00	0	14.0
2004	601,075.73	520,932	601,076	1.0000	0	2.00	0	13.0
2005	314,887.27	251,910	314,887	1.0000	0	3.00	0	12.0
2006	242,960.20	178,171	225,107	0.9265	17,853	4.00	4,463	11.0
2007	248,080.29	165,387	208,956	0.8423	39,125	5.00	7,825	10.0
2008	236,641.24	141,985	179,389	0.7581	57,253	6.00	9,542	9.0
2009	5,119.92	2,731	3,450	0.6738	1,670	7.00	239	8.0
2010	254,717.42	118,868	150,182	0.5896	104,535	8.00	13,067	7.0
2011	172,864.70	69,146	87,361	0.5054	85,503	9.00	9,500	6.0
2012	112,903.31	37,634	47,549	0.4211	65,355	10.00	6,536	5.0
2013	107,166.27	28,578	36,106	0.3369	71,060	11.00	6,460	4.0
2014	160,507.84	32,102	40,558	0.2527	119,950	12.00	9,996	3.0
2015	157,433.03	20,991	26,521	0.1685	130,912	13.00	10,070	2.0
2016	73,627.82	4,909	6,202	0.0842	67,426	14.00	4,816	1.0
2017	2,493,365.06	0	0	0.0000	2,493,365	15.00	166,224	0.0
TOTAL	5,632,480.79	1,994,398	2,378,475		3,254,006		248,738	

COMPOSITE ANNUAL ACCRUAL RATE	4.42%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.42
COMPOSITE AVERAGE AGE (YEARS)	5.31
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	9.69

Fortis BC Electrical

Account #: 391.10 - Computer Hardware

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 4
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	2,197,691.53	1,648,269	1,918,721	0.8731	278,970	1.00	278,970	3.0
2015	2,434,736.50	1,217,368	1,417,118	0.5820	1,017,619	2.00	508,810	2.0
2016	2,385,491.84	596,373	694,228	0.2910	1,691,264	3.00	563,755	1.0
2017	4,825,018.65	0	0	0.0000	4,825,019	4.00	1,206,255	0.0
TOTAL	11,842,938.52	3,462,010	4,030,066		7,812,872		2,557,789	

COMPOSITE ANNUAL ACCRUAL RATE	21.60%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.34
COMPOSITE AVERAGE AGE (YEARS)	1.17
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	2.83

Fortis BC Electrical

Account #: 391.20 - Computer Software

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 8
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2010	4,441,171.09	3,886,025	4,441,171	1.0000	0	1.00	0	7.0
2011	4,407,259.70	3,305,445	3,959,957	0.8985	447,303	2.00	223,652	6.0
2012	4,749,775.58	2,968,610	3,556,425	0.7488	1,193,351	3.00	397,784	5.0
2013	4,187,675.44	2,093,838	2,508,439	0.5990	1,679,236	4.00	419,809	4.0
2014	4,577,960.47	1,716,735	2,056,666	0.4493	2,521,294	5.00	504,259	3.0
2015	4,016,338.03	1,004,085	1,202,904	0.2995	2,813,435	6.00	468,906	2.0
2016	4,253,715.68	531,714	636,999	0.1498	3,616,716	7.00	516,674	1.0
2017	6,086,390.95	0	0	0.0000	6,086,391	8.00	760,799	0.0
TOTAL	36,720,286.94	15,506,451	18,362,561		18,357,726		3,291,881	

COMPOSITE ANNUAL ACCRUAL RATE	8.96%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.50
COMPOSITE AVERAGE AGE (YEARS)	3.38
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	4.62

Fortis BC Electrical

Account #: 391.60 - AMI Computer Software

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 10
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	6,166,997.22	1,850,099	1,850,099	0.3000	4,316,898	7.00	616,700	3.0
2015	2,723,309.26	544,662	544,662	0.2000	2,178,647	8.00	272,331	2.0
2016	380,945.27	38,095	38,095	0.1000	342,851	9.00	38,095	1.0
2017	326,157.94	0	0	0.0000	326,158	10.00	32,616	0.0
TOTAL	9,597,409.69	2,432,856	2,432,856		7,164,554		959,741	

COMPOSITE ANNUAL ACCRUAL RATE	10.00%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.25
COMPOSITE AVERAGE AGE (YEARS)	2.53
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	7.47

Fortis BC Electrical

Account #: 392.10 - Light Duty Vehicles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L1
ASL: 12
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1995	63,216.00	40,190	53,734	0.8500	0	3.02	0	22.0
2002	7,924.52	4,074	6,736	0.8500	0	4.74	0	15.0
2004	21,770.45	10,298	18,505	0.8500	0	5.32	0	13.0
2005	220,217.49	99,366	185,982	0.8445	1,203	5.63	214	12.0
2006	180,844.05	77,485	145,027	0.8019	8,690	5.95	1,460	11.0
2007	153,427.46	62,091	116,215	0.7575	14,199	6.29	2,259	10.0
2008	393,316.33	149,398	279,626	0.7109	54,693	6.64	8,240	9.0
2009	92,177.45	32,616	61,047	0.6623	17,304	7.00	2,470	8.0
2010	50,245.65	16,410	30,715	0.6113	11,994	7.39	1,623	7.0
2011	1,350,298.87	401,441	751,372	0.5564	396,382	7.80	50,800	6.0
2012	564,554.18	148,885	278,667	0.4936	201,204	8.28	24,309	5.0
2013	869,035.37	194,855	364,707	0.4197	373,973	8.83	42,331	4.0
2014	466,744.93	83,031	155,409	0.3330	241,324	9.49	25,433	3.0
2015	61,781.16	7,695	14,403	0.2331	38,111	10.24	3,721	2.0
2016	52,503.56	3,403	6,369	0.1213	38,259	11.09	3,451	1.0
2017	221,831.83	0	0	0.0000	188,557	12.00	15,713	0.0
TOTAL	4,769,889.30	1,331,238	2,468,512		1,585,894		182,024	

COMPOSITE ANNUAL ACCRUAL RATE	3.82%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.52
COMPOSITE AVERAGE AGE (YEARS)	5.99
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	8.06

Fortis BC Electrical

Account #: 392.20 - Heavy Duty Vehicles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L2.5
ASL: 16
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
1979	11,705.00	9,081	6,111	0.5221	3,839	1.40	2,751	38.0
1980	78,670.00	60,313	40,584	0.5159	26,286	1.57	16,755	37.0
1982	756.00	567	381	0.5043	261	1.89	138	35.0
1987	15,844.00	11,263	7,578	0.4783	5,889	2.62	2,248	30.0
1989	31,610.00	21,899	14,735	0.4662	12,133	2.96	4,100	28.0
1991	8,150.00	5,479	3,687	0.4524	3,240	3.34	969	26.0
1993	49,387.00	32,072	21,581	0.4370	20,398	3.78	5,402	24.0
1995	181,575.00	113,417	76,317	0.4203	78,022	4.24	18,392	22.0
1996	30,159.00	18,455	12,418	0.4118	13,217	4.48	2,949	21.0
2002	282,398.18	154,194	103,755	0.3674	136,284	5.72	23,817	15.0
2003	30,765.02	16,444	11,065	0.3597	15,085	5.94	2,540	14.0
2004	42,125.12	21,922	14,751	0.3502	21,056	6.20	3,394	13.0
2005	672,948.59	338,232	227,591	0.3382	344,415	6.54	52,670	12.0
2006	2,263,020.44	1,087,018	731,439	0.3232	1,192,128	6.96	171,324	11.0
2007	3,145,082.57	1,425,362	959,106	0.3050	1,714,214	7.47	229,507	10.0
2008	873,047.18	367,765	247,464	0.2834	494,626	8.07	61,286	9.0
2009	1,588,425.80	611,262	411,310	0.2589	938,852	8.76	107,220	8.0
2010	555,390.60	191,305	128,727	0.2318	343,355	9.52	36,081	7.0
2011	1,676,916.97	504,404	339,406	0.2024	1,085,973	10.34	105,046	6.0
2012	1,099,230.49	279,877	188,325	0.1713	746,021	11.21	66,566	5.0
2013	2,211,089.15	456,681	307,294	0.1390	1,572,132	12.11	129,798	4.0
2014	925,587.14	145,069	97,615	0.1055	689,134	13.05	52,808	3.0
2015	1,937,477.54	204,251	137,438	0.0709	1,509,418	14.02	107,696	2.0
2016	2,391,578.55	126,784	85,311	0.0357	1,947,531	15.00	129,817	1.0
2017	2,285,958.17	13	9	0.0000	1,943,055	16.00	121,442	0.0

Fortis BC Electrical

Account #: 392.20 - Heavy Duty Vehicles

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: L2.5
ASL: 16
Net Salvage: 15%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
TOTAL	22,388,897.51	6,203,129	4,173,998		14,856,565		1,454,716	

COMPOSITE ANNUAL ACCRUAL RATE	6.50%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.19
COMPOSITE AVERAGE AGE (YEARS)	6.18
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	10.78

Fortis BC Electrical

Account #: 394.00 - Tools and Work Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	514,101.97	479,829	514,102	1.0000	0	1.00	0	14.0
2004	518,418.44	449,296	518,418	1.0000	0	2.00	0	13.0
2005	758,607.61	606,886	744,783	0.9818	13,824	3.00	4,608	12.0
2006	859,648.67	630,409	773,651	0.9000	85,997	4.00	21,499	11.0
2007	936,499.18	624,333	766,194	0.8181	170,305	5.00	34,061	10.0
2008	587,124.42	352,275	432,319	0.7363	154,806	6.00	25,801	9.0
2009	657,856.91	350,857	430,579	0.6545	227,278	7.00	32,468	8.0
2010	495,084.56	231,039	283,536	0.5727	211,548	8.00	26,444	7.0
2011	491,900.92	196,760	241,468	0.4909	250,432	9.00	27,826	6.0
2012	530,907.08	176,969	217,180	0.4091	313,727	10.00	31,373	5.0
2013	459,332.99	122,489	150,321	0.3273	309,012	11.00	28,092	4.0
2014	497,378.07	99,476	122,079	0.2454	375,300	12.00	31,275	3.0
2015	412,125.61	54,950	67,436	0.1636	344,690	13.00	26,515	2.0
2016	565,395.28	37,693	46,258	0.0818	519,138	14.00	37,081	1.0
2017	524,268.37	0	0	0.0000	524,268	15.00	34,951	0.0
TOTAL	8,808,650.08	4,413,260	5,308,325		3,500,325		361,994	

COMPOSITE ANNUAL ACCRUAL RATE	4.11%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.60
COMPOSITE AVERAGE AGE (YEARS)	7.52
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	7.48

Fortis BC Electrical

Account #: 397.00 - Communications Structures and Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	375,787.93	350,735	375,788	1.0000	0	1.00	0	14.0
2004	157,810.38	136,769	157,810	1.0000	0	2.00	0	13.0
2005	3,912,507.89	3,130,006	3,809,185	0.9736	103,323	3.00	34,441	12.0
2006	1,707,514.07	1,252,177	1,523,886	0.8925	183,628	4.00	45,907	11.0
2007	943,165.55	628,777	765,215	0.8113	177,950	5.00	35,590	10.0
2008	1,455,928.05	873,557	1,063,110	0.7302	392,818	6.00	65,470	9.0
2009	836,413.90	446,087	542,884	0.6491	293,530	7.00	41,933	8.0
2010	539,966.15	251,984	306,662	0.5679	233,304	8.00	29,163	7.0
2011	638,613.30	255,445	310,874	0.4868	327,739	9.00	36,415	6.0
2012	487,162.37	162,387	197,624	0.4057	289,539	10.00	28,954	5.0
2013	354,912.17	94,643	115,180	0.3245	239,732	11.00	21,794	4.0
2014	700,748.83	140,150	170,561	0.2434	530,188	12.00	44,182	3.0
2016	12,636.48	842	1,025	0.0811	11,611	14.00	829	1.0
2017	987,696.31	0	0	0.0000	987,696	15.00	65,846	0.0
TOTAL	13,110,863.38	7,723,561	9,339,804		3,771,059		450,525	

COMPOSITE ANNUAL ACCRUAL RATE	3.44%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.71
COMPOSITE AVERAGE AGE (YEARS)	8.84
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	6.16

Fortis BC Electrical

Account #: 397.10 - Fibre - Communication

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION
BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2003	2,376,766.24	2,218,315	2,194,749	0.9234	182,017	1.00	182,017	14.0
2004	157,775.77	136,739	135,286	0.8575	22,489	2.00	11,245	13.0
2005	1,447,522.50	1,158,018	1,145,716	0.7915	301,807	3.00	100,602	12.0
2006	2,783.11	2,041	2,019	0.7255	764	4.00	191	11.0
2007	4,585,814.97	3,057,210	3,024,732	0.6596	1,561,083	5.00	312,217	10.0
2008	198,018.17	118,811	117,549	0.5936	80,469	6.00	13,412	9.0
2009	246,703.46	131,575	130,177	0.5277	116,526	7.00	16,647	8.0
2011	55,183.95	22,074	21,839	0.3958	33,345	9.00	3,705	6.0
2012	1,053,253.29	351,084	347,355	0.3298	705,899	10.00	70,590	5.0
2013	79,492.11	21,198	20,973	0.2638	58,519	11.00	5,320	4.0
2014	1,777,243.51	355,449	351,673	0.1979	1,425,571	12.00	118,798	3.0
2015	1,501.09	200	198	0.1319	1,303	13.00	100	2.0
2016	2,254.46	150	149	0.0660	2,106	14.00	150	1.0
2017	11,274.82	0	0	0.0000	11,275	15.00	752	0.0
TOTAL	11,995,587.45	7,572,864	7,492,415		4,503,172		835,744	

COMPOSITE ANNUAL ACCRUAL RATE	6.97%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.62
COMPOSITE AVERAGE AGE (YEARS)	9.47
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	5.53

Fortis BC Electrical

Account #: 397.20 - AMI Communications Structures and Equipment

CALCULATED ANNUAL ACCRUAL AND ACCRUED DEPRECIATION

BASED ON ORIGINAL COST AS OF DECEMBER 31, 2017

ALG - Remaining Life
Survivor Curve: SQ
ASL: 15
Net Salvage: 0%
Truncation Year:

Year	Original Cost	Calculated Accumulated Depreciation	Allocated Actual Booked Amount	Accumulated Depreciation Factor	Net Book Value	ALG Remaining Life	Annual Accrual	Average Age
2014	2,274,693.23	454,939	455,166	0.2001	1,819,527	12.00	151,627	3.0
2015	1,632,846.04	217,713	217,822	0.1334	1,415,024	13.00	108,848	2.0
2016	952,988.89	63,533	63,564	0.0667	889,425	14.00	63,530	1.0
2017	109,203.68	0	0	0.0000	109,204	15.00	7,280	0.0
TOTAL	4,969,731.84	736,184	736,552		4,233,180		331,286	

COMPOSITE ANNUAL ACCRUAL RATE	6.67%
THEORETICAL ACCUMULATED DEPRECIATION FACTOR	0.15
COMPOSITE AVERAGE AGE (YEARS)	2.22
DIRECTED WEIGHTED ALG COMPOSITE REMAINING LIFE (YEARS)	12.78

SECTION 9

9 ESTIMATION OF SURVIVOR CURVES

9.1 Average Service Life

All assets have a service life, which is defined as "the period of time from its installation until it is retired from service" [4]. All account groups of property are made up of various assets with differing service lives and investment values. To calculate a depreciation rate, one must first calculate an average life for all assets in a single account. This can be done by ascertaining the age at retirement for every asset in an account and plotting it as a percentage of the units surviving at each age interval (a "Survivor Curve"). From the average life for each account, remaining lives can then be found which are then used to calculate the annual depreciation accruals and ultimately depreciation rate. A discussion of the general concept of survivor curves is presented and the Iowa type survivor curves are reviewed.

9.2 Survivor Curves

A survivor curve is defined as "a graph of the percent of units remaining in service expressed as a function of age" [5]. To calculate the average life of the group, the remaining life expectancy, the probable life and the frequency curve, one must first create a survivor curve. Figure 1, shows a typical 40-R4 smoothed survivor curve as well as the accompanying derived curves. The type 40-R4 refers to the Iowa type curve, whose designation will be explained in further detail in the next section

To calculate the average service life, one must calculate the area under the survivor curve and divide by the percent surviving at age zero. The remaining life is equal to the area under the survivor curve and to the right of the current age, divided by the percent surviving at the current age. In Figure 1, for example, the hatched area to the right of age 45 divided by 28.9 percent surviving balance represents the remaining life for an asset that has reached that age. The probable life is "the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age." [6] If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve is calculated by taking the difference between the percent surviving on successive years on the survivor curve[7]. Alternatively, frequency can be empirically determined by finding the amount of retirements at any given age. Plotting retirement frequency from the youngest to oldest ages and then taking the cumulative frequencies will generate percent surviving versus age.

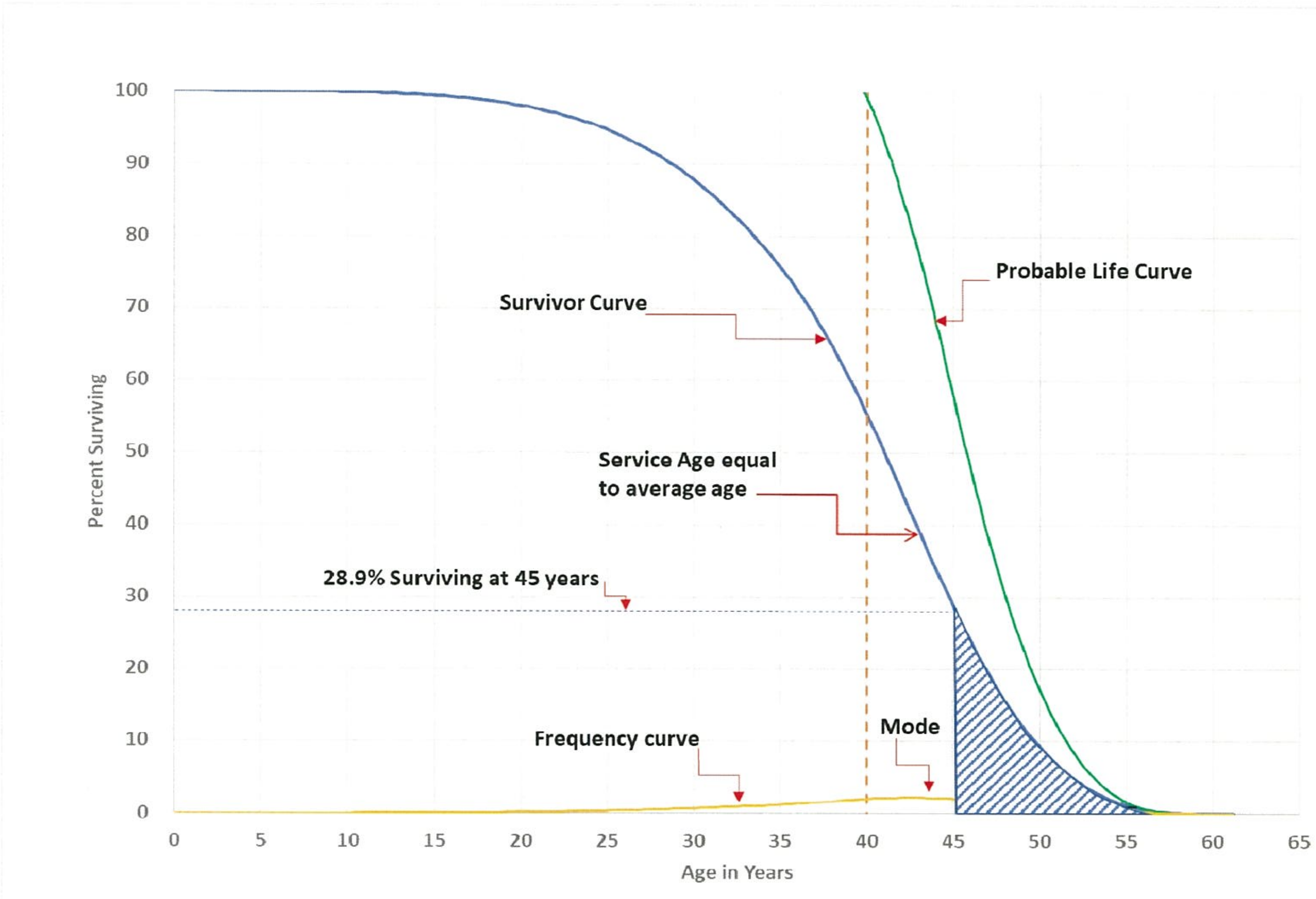
[4] Wolf, Frank K. and W. Chester Fitch, Depreciation Systems (Iowa State University Press, 1994), 21

[5] *Ibid*, 23.

[6] *Ibid*, 29.

[7] *Ibid*, 23-24.

FIGURE 1: TYPICAL SURVIVOR CURVE (40-R4) AND DERIVED CURVES



9.3 Iowa Type Curves

In 1931, Robley Winfrey and Edwin Kurtz of the Engineering Research Institute at Iowa State University published Bulletin 103, which laid the groundwork for what would eventually be known as the Iowa Curves. "The 13 type curves can be used as valuable aids in forecasting the probable future service lives of individual items and of groups of items of different kinds of physical equipment" [8]. The 13 curves described in Bulletin 103 eventually became a series of 22 generalized survivor curves which are used throughout the regulated utility industry. These 22 curves were described in Bulletin 125, published in 1967 by Harold A. Cowles, which became known as the Iowa curves.

The Iowa curves are organized with three variables: the average life of the plant; the location of the mode; and the variation of the life. All Iowa curves have both a letter and a number to represent the shape and height of the mode. The L curves, or left-moded curves, are used when the mode of the curve should be to the left of the average life. There are six L curves are presented in Figure 2. The R curves, or right-moded, are used when the mode of the curve should be to the right of the average life. There are five R curves, which are presented in Figure 3. The S curves, or symmetrically-moded, are used when the mode is equal to the average life. There are seven S curves, which are presented in Figure 4. The O curves, or origin curves, are used when the mode occurs at age 0. There are four O curves, which are presented in Figure 5. There are some occasions where it is appropriate to use a half curve. In these cases, the curve is assumed to be exactly half way between the two curves.

In addition to Bulletin 125, Iowa curves have also been presented in subsequent Experiment Station bulletins and in the text Engineering Valuation and Depreciation[9]. In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student, submitted a thesis[10] presenting his development of the fourth family consisting of the four O-type survivor curves.

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[8] *Ibid*, 21

[9] Marston, Anson, Robley Winfrey and Jean C. Hempstead, Engineering Valuation and Depreciation (The Iowa State University Press, 1953)

[10] Couch, Frank V. B., Jr., Classification of Type O Retirement Characteristics of Industrial Property Unpublished M.S. Thesis (Engineering Valuation, Library, Iowa State College, Ames, Iowa, 1957)

FIGURE 2: LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

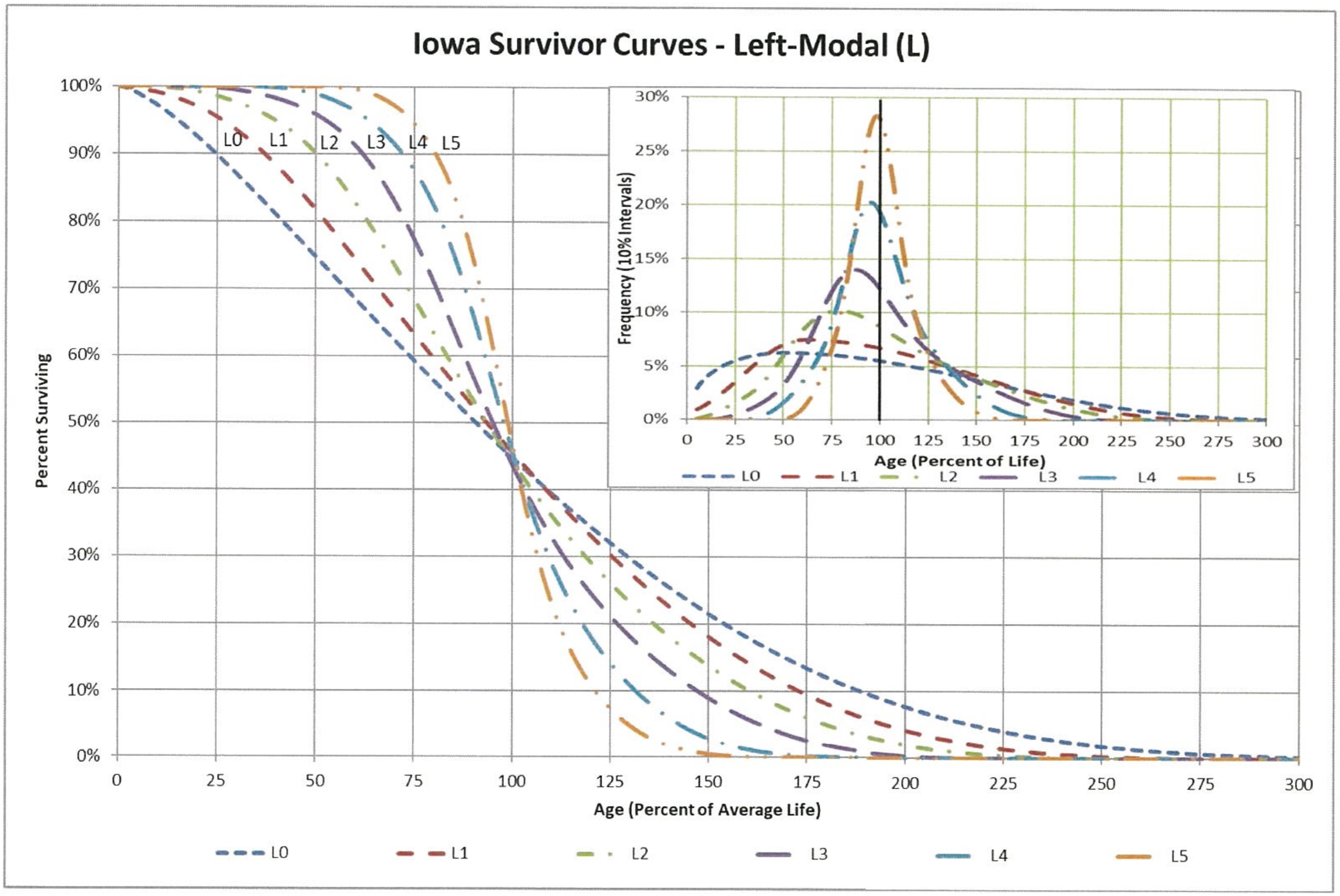


FIGURE 3: RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

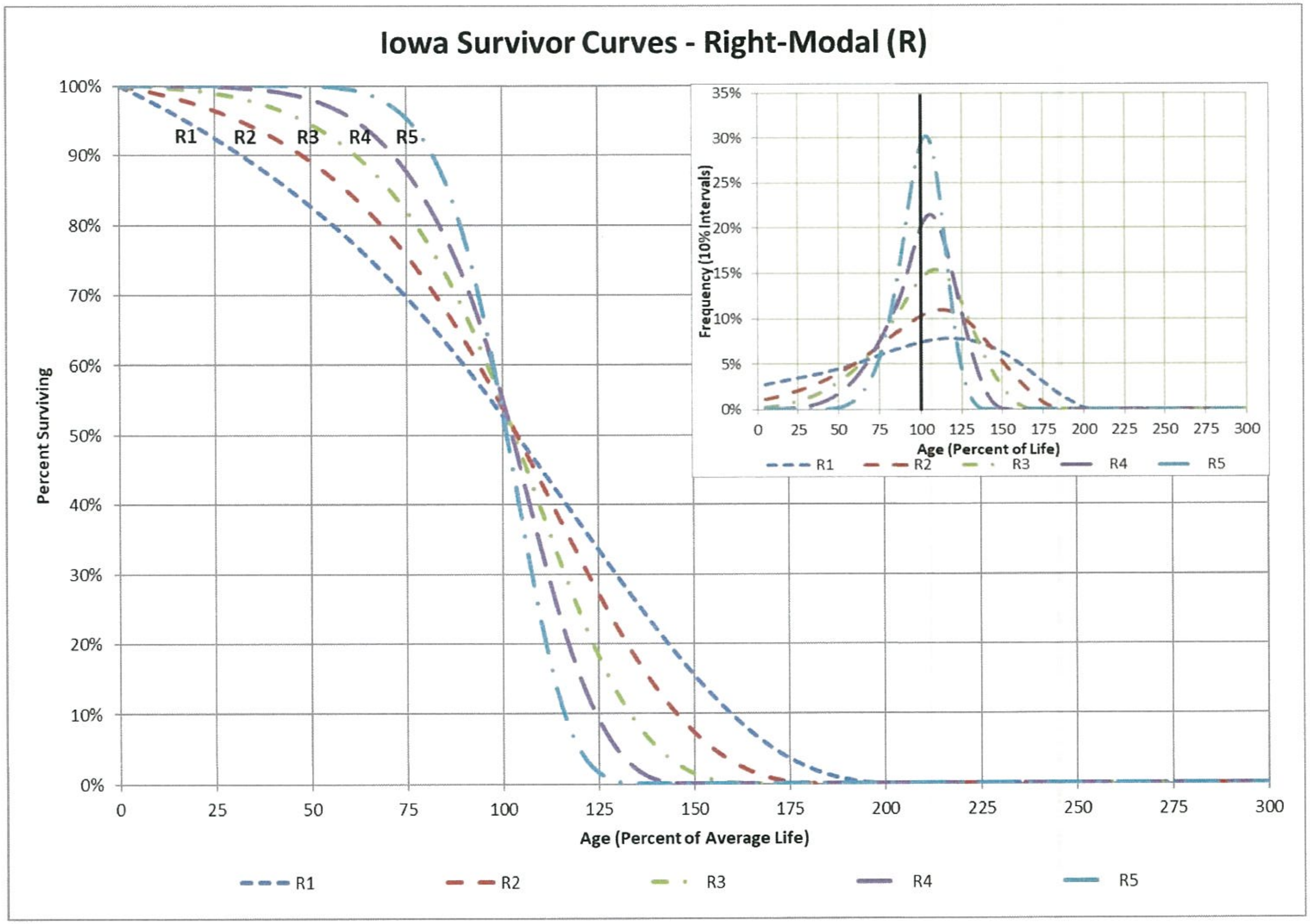


FIGURE 4: SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

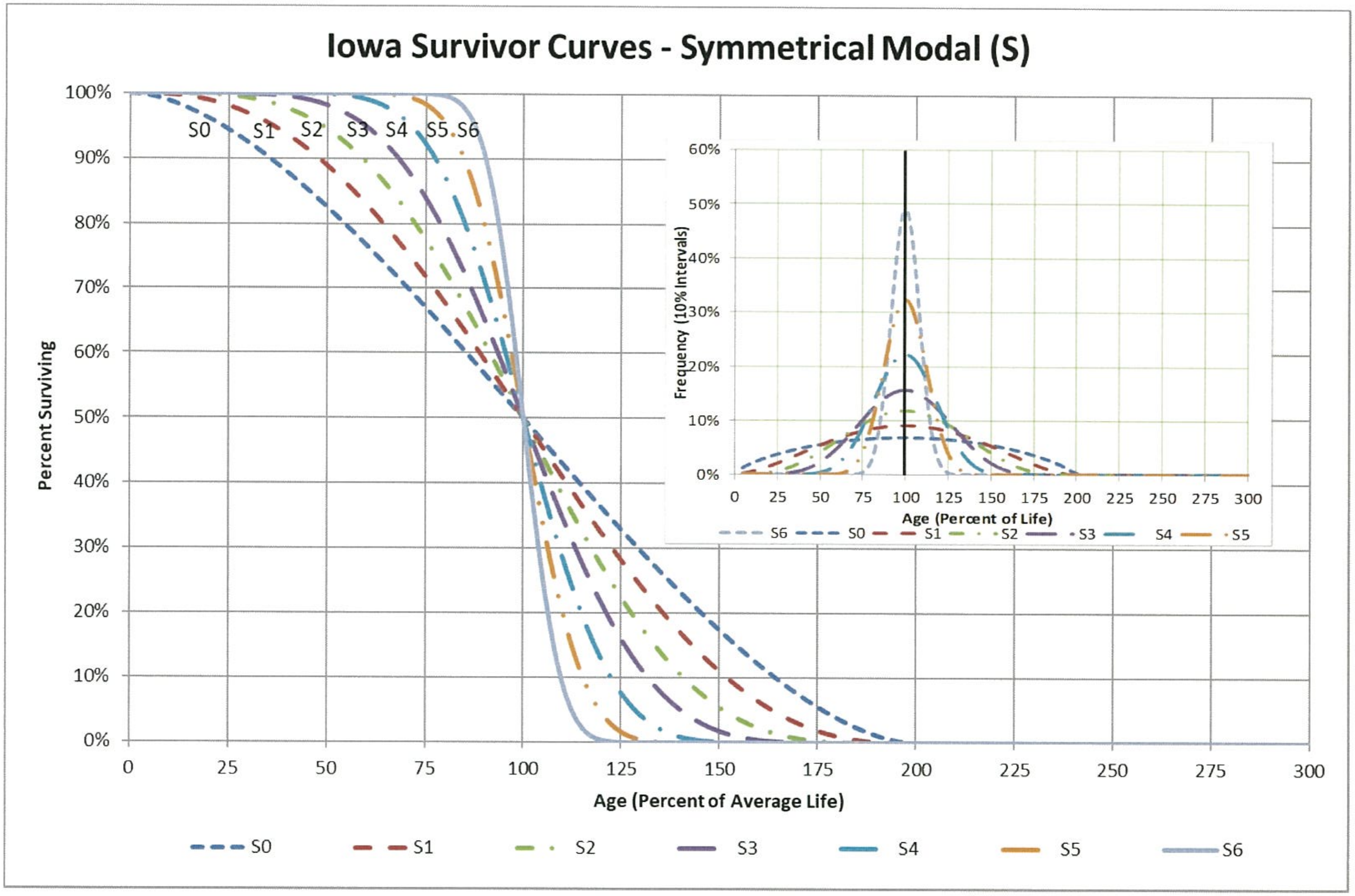
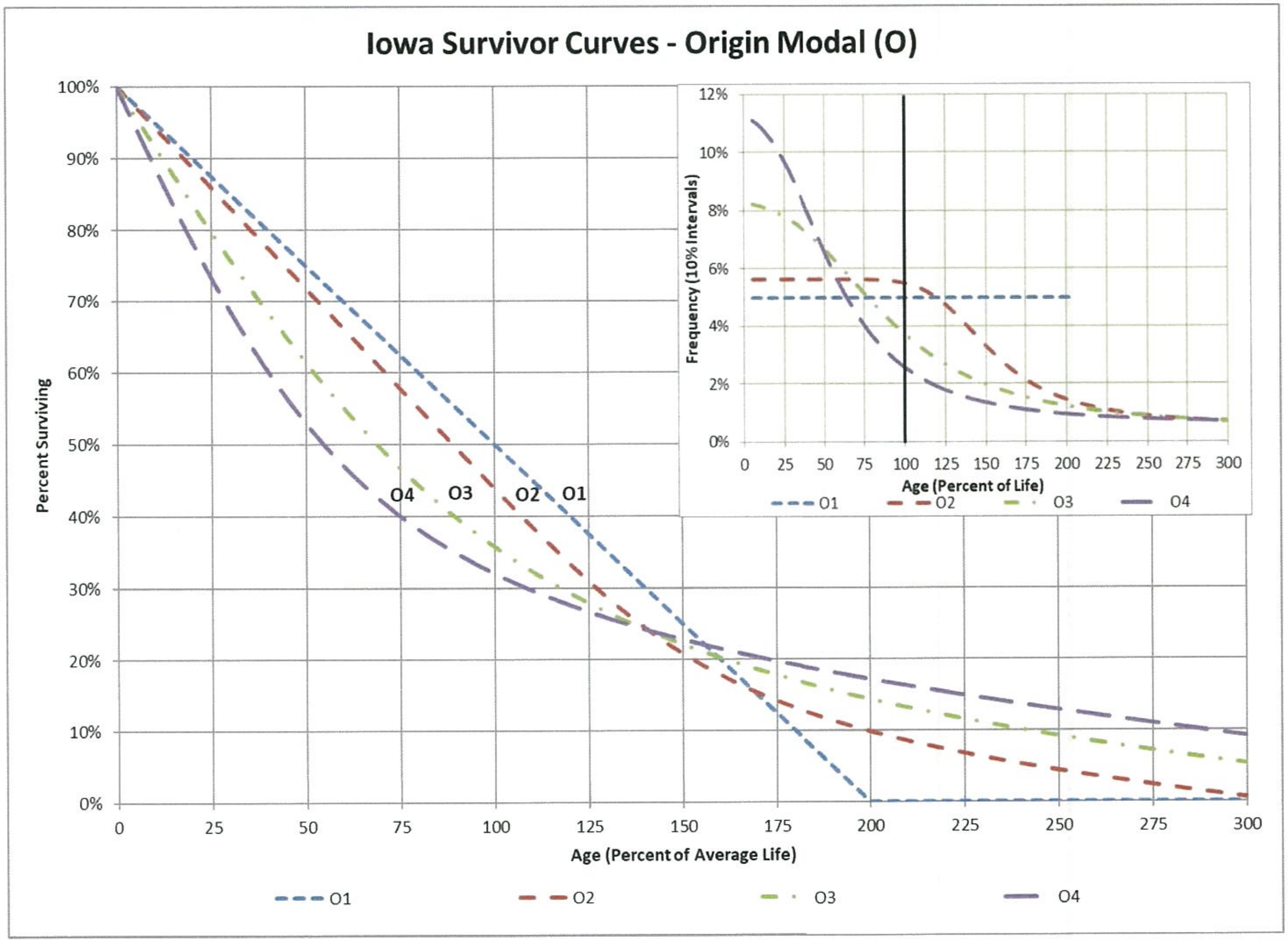


FIGURE 5: ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES



9.4 Retirement Rate Method of Analysis

The retirement rate method is a widely accepted actuarial method used to create survivor curves. This method is also referred to as an original life table. These survivor curves can then be used to determine the average service life of a plant account. The retirement rate method is thoroughly explained in several publications, including Statistical Analyses of Industrial Property Retirements, [11] Engineering Valuation and Depreciation [12] and Depreciation Systems.[13]

The retirement rate method is a subgroup of the placement and the experience band methods, as described in "Depreciation Systems". The placement band method creates a survivor curve which describes the life characteristics of assets placed into service during a selected timeframe. The experience band method creates a survivor curve which describes the life characteristics of assets removed from service during a selected time frame. The retirement rate method creates both placement and experience bands to give the most complete or representative data. An example of the calculations used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

9.5 Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data was compiled in the manner presented in Schedules 1 and 2. In Schedule 1 (page 9-10), the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the asset invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4 ½ and 5 ½ years (2008 - 2003) on the basis that approximately one-half of the amount of property was installed prior to and after July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one-half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2016 retirements of the 2011 installations. Thus, the total amount of $143,000 for age interval 4½-5½ equals the sum of:

$10 + $12 + $13 + $11 + $13 + $13 + $15 + $17 + $19 + $20= $143 k

[11] Anson, Winfrey & Hempstead, *supra* note 3

[12] Anson, Winfrey & Hempstead, *supra* note 3

[13] Wolf & Fitch, supra note 1

Other transactions which affect the group are recorded in a similar manner in Schedule 2 (page 9-11). The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements, but are used in developing the exposures at the beginning of each age interval.

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Retrements (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	**53**	**68**	**86**	**106**	**128**	**157**	**196**	**231**	**273**	**308**	**1,606**	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Acquisitions, Transfers and Sales (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total Durring Age Interval (12)	Age Interval (13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	-	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017												0-½
Total	**-**	**-**	**-**	**-**	**-**	**-**	**60**	**(30)**	**22**	**(102)**	**(50)**	

[a] *Transfer Affecting Exposures at Beginning of Year*
[b] *Transfer Affecting Exposures at End of Year*
[c] *Sale with Continued Use*
Parentheses denote Credit amount.

9.6 Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 (page 9-13). The surviving plant at the beginning of each year from 2008 through 2017 is recorded by year in the portion of the table titled "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition, are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	=	amount of addition	=	$750,000
Exposures at age ½	=	$750,000 - $ 8,000	=	$742,000
Exposures at age 1½	=	$742,000 - $18,000	=	$724,000
Exposures at age 2½	=	$724,000 - $20,000 - $19,000	=	$685,000
Exposures at age 3½	=	$685,000 - $22,000	=	$663,000

For the entire experience band 2008-2017, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Schedule 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained by summing:

$255 + $268 + $ 284 + $311 + $334 + $374 + $405 + $448 + $501 $ $609 = $3,789k

SCHEDULE 3 – PLANT EXPOSED TO RETIREMENT AT THE BEGINNING OF EACH YEAR, 2008 -2017 – SUMMARIZED BY AGE INTERVAL

Experience Band 2008 - 2017

Placement Band 2003-2017

Exposures (Thousands of Dollars)
Annual Survivors at the Beginning of the Year

Year Placed (1)	2008 (2)	2009 (3)	2010 (4)	2011 (5)	2012 (6)	2013 (7)	2014 (8)	2015 (9)	2016 (10)	2017 (11)	Total at Beginning of Age Interval (12)	Age Interval (13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	257	346	334	321	307	267	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	923	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	**1,975**	**2,382**	**2,724**	**3,318**	**3,872**	**4,494**	**5,247**	**5,987**	**6,852**	**7,796**	**44,780**	

[a] *Additions during the year.*

1555	1922	2214	2738	3212	3744	4397	5027	5772	6576	44780
420	460	510	580	660	750	850	960	1080	1220	0
1975	2382	2724	3318	3872	4494	5247	5987	6852	7796	44780

9.7 Original Life Tables

The original life table, illustrated in Schedule 4 (page 9-15) is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule. The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100 percent at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15		
Exposures at age 4½	=	\$3,789,000		
Retirements from age 4½ to 5½	=	\$143,000		
Retirement Ratio	=	\$143,000 ÷ \$3,789,000	=	0.0377
Survivor Ratio	=	1.000 - 0.0377	=	0.9623
Percent surviving at age 5½	=	(88.15) x (0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless. The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

SCHEDULE 4 ORIGINAL LIFE TABLE - CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017				Placement Band 2003-2017	
Age at Beginning of Interval	**Exposures at Beginning of Age Interval**	**Retirements During Age Interval**	**Retirement Ratio**	**Survivor Ratio**	**% Surviving at Beginning of Age Interval**
0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.6
12.5	323	44	0.1362	0.8638	48.9
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	**44,780**	**1,606**			

- Exposure and Retirement Amounts are in Thousands of Dollars
- Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
- Column 3 from Schedule 1, Column 12, Retirements for Each Year.
- Column 4 = Column 3 divided by Column 2.
- Column 5 = 1.0000 minus Column 4.
- Column 6 = Column 5 multiplied by Column 6 as of the Preceding Age Interval.

9.8 Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100 percent to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percentages surviving at ages in years. Each original survivor curve was compared to the Iowa curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Schedule 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12-year average life appears to be the best fit and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

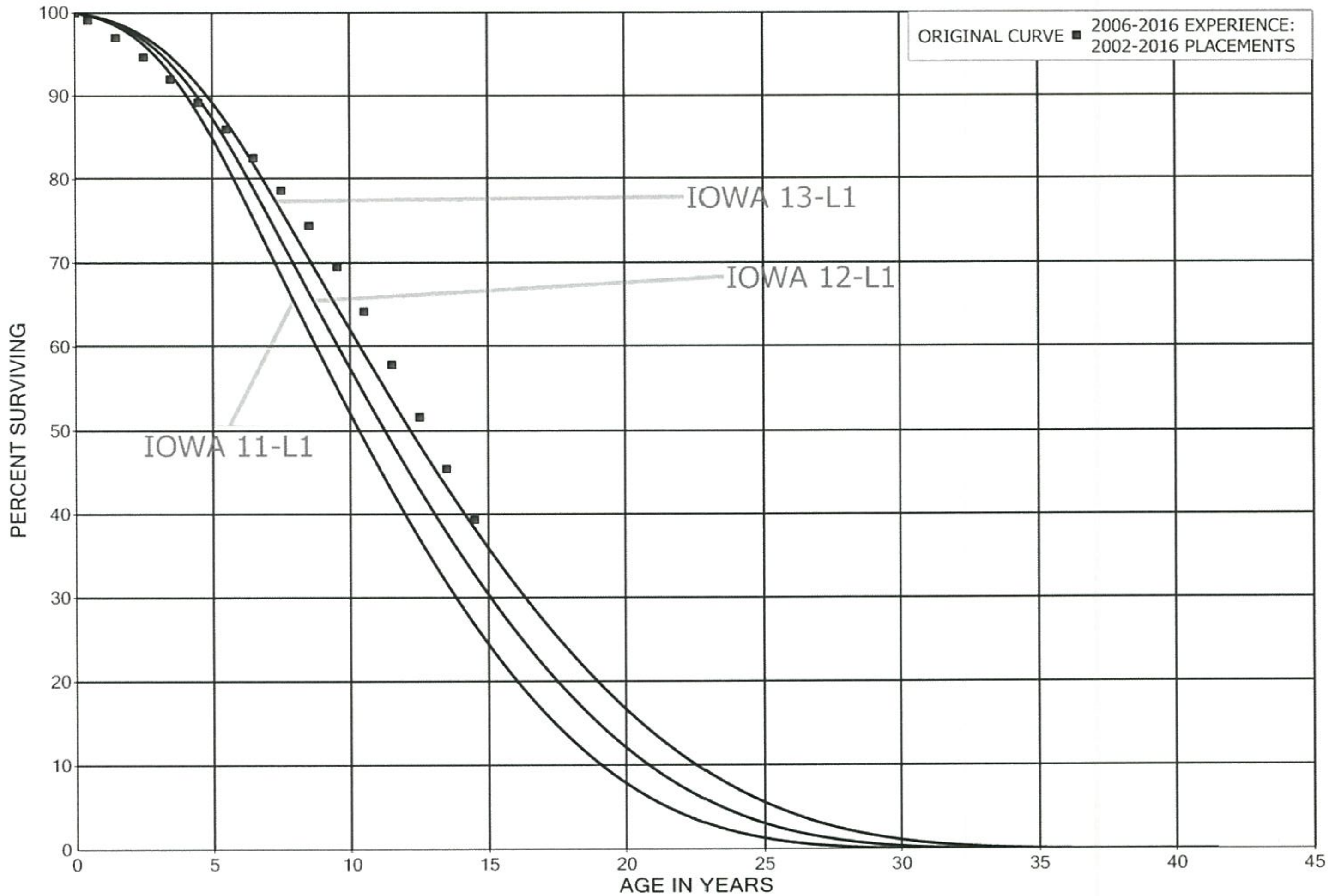


FIGURE 7: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A SO IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

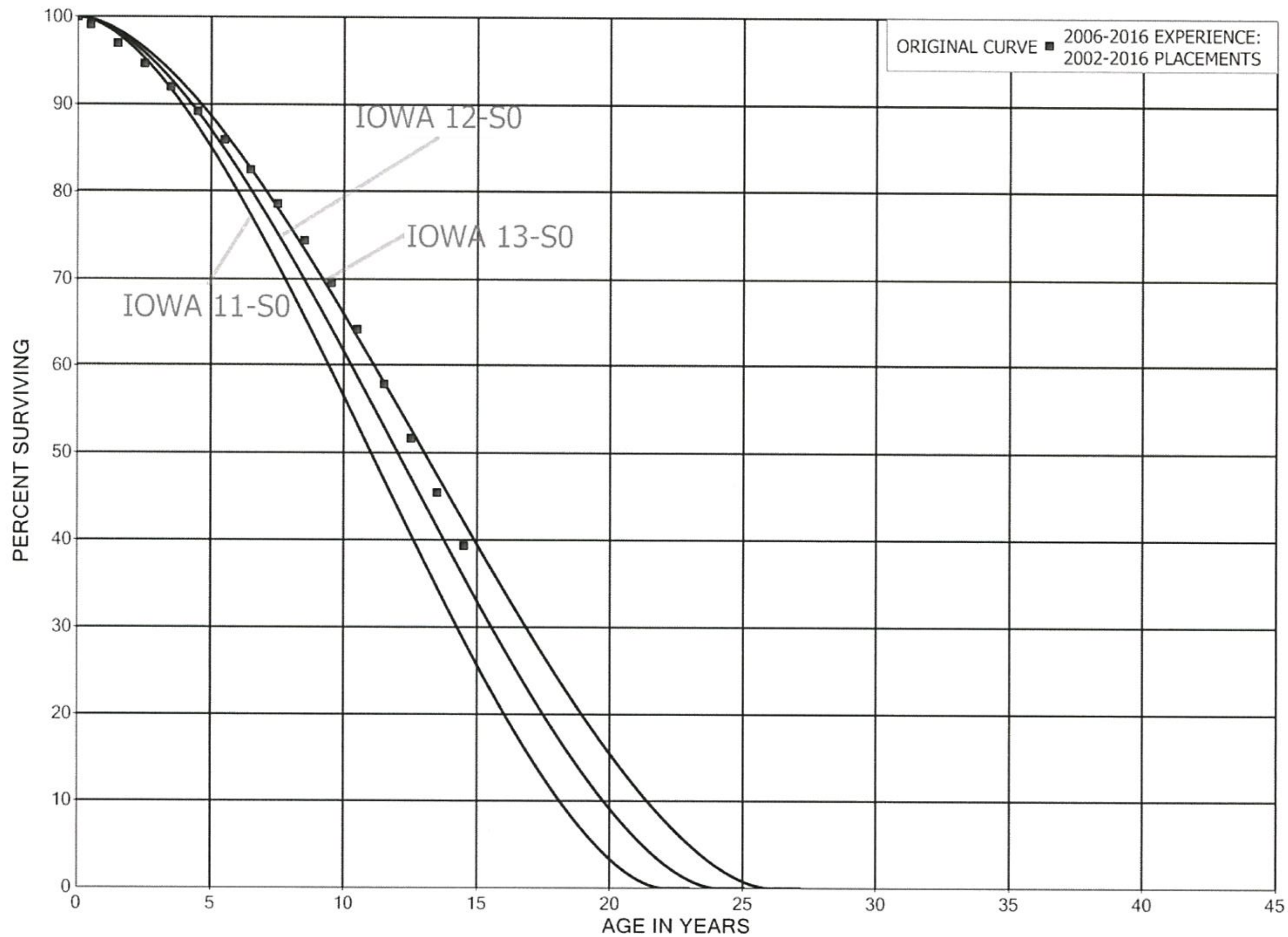


FIGURE 8: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A R1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES

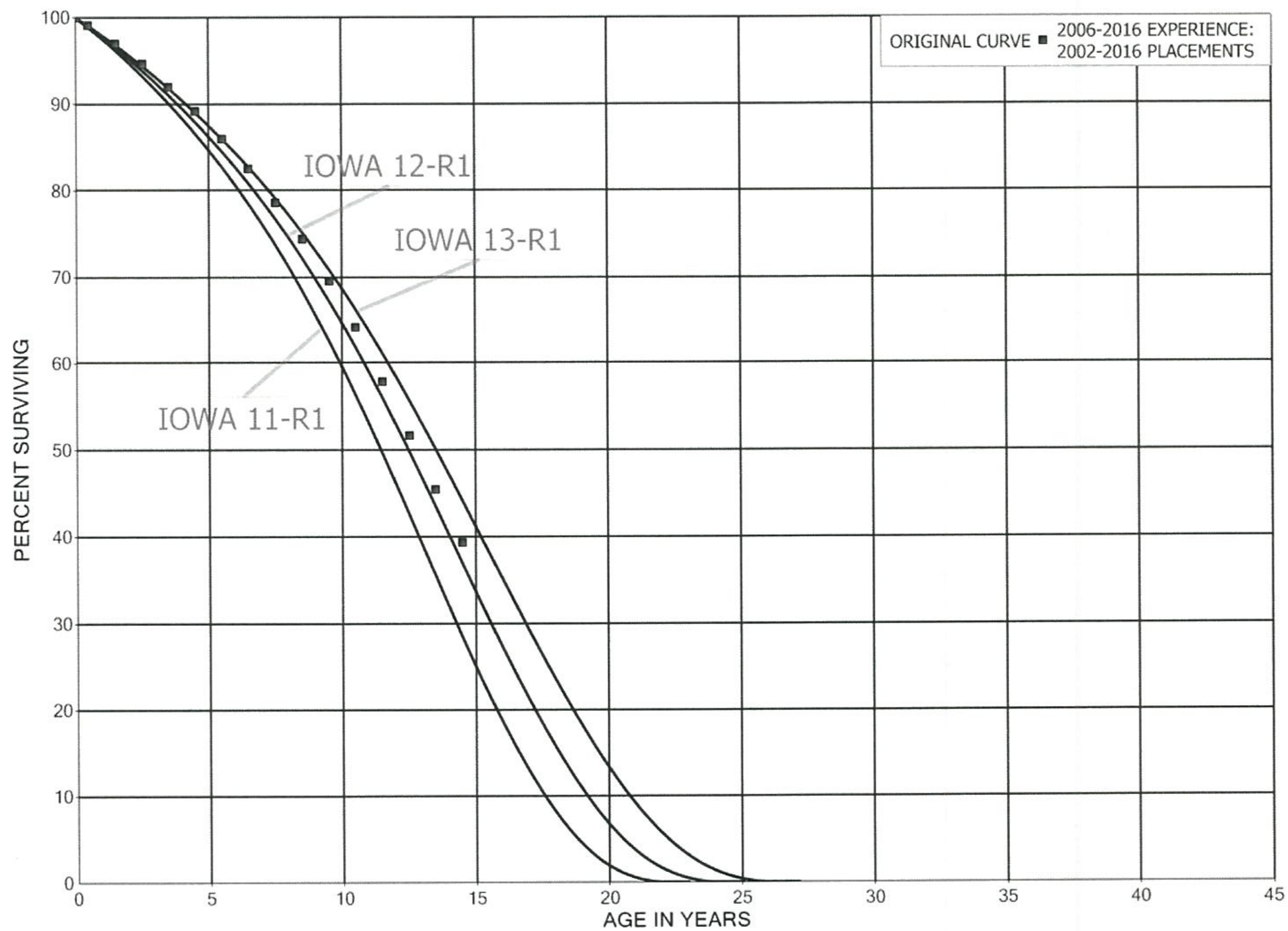
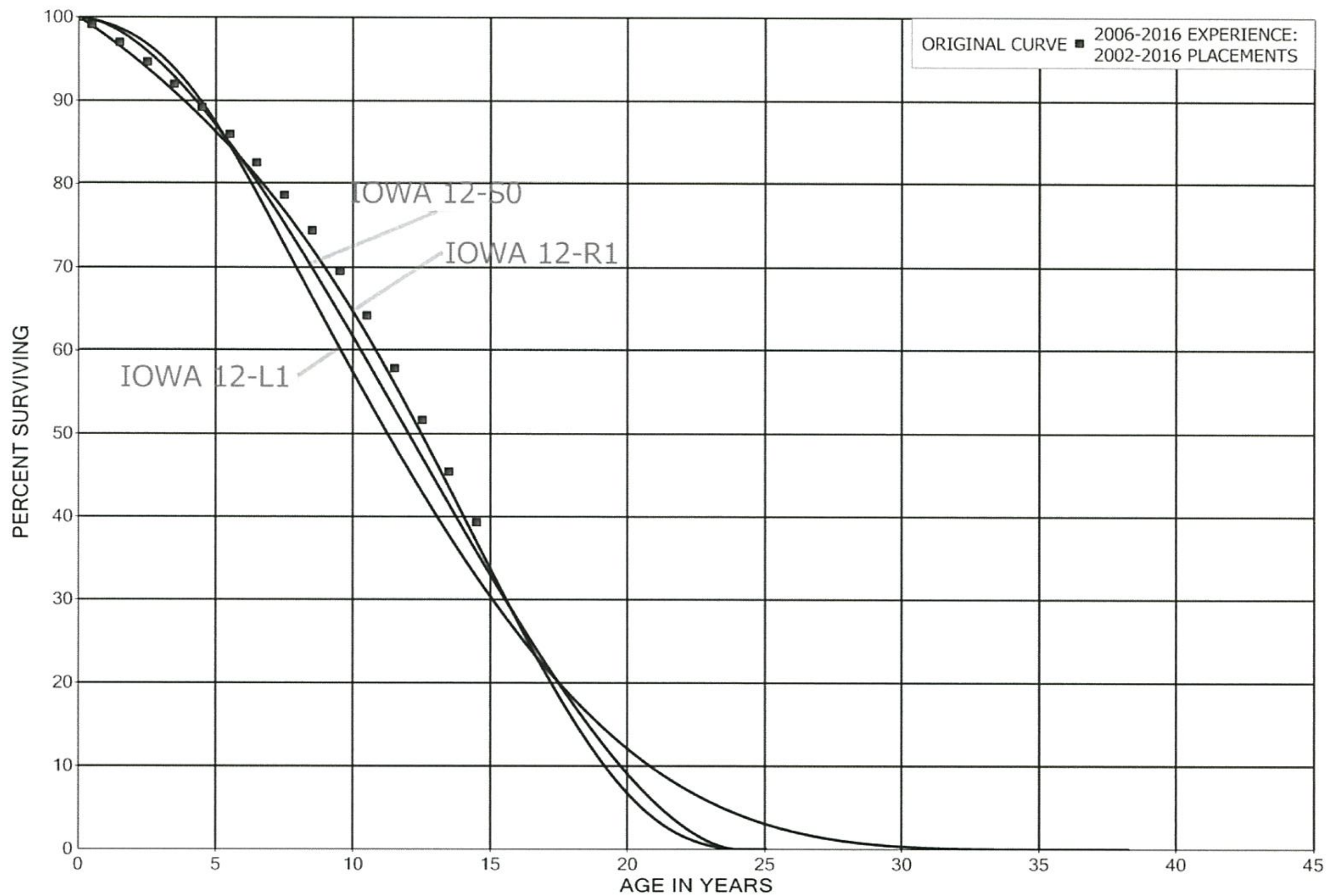


FIGURE 9: ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH A L1 IOWA TYPE CURVE ORIGINAL AND SMOOTH SURVIVOR CURVES



SECTION 10

10 ESTIMATION OF NET SALVAGE

The estimates of net salvage were based primarily on the professional judgment of Concentric, based in part on historical data, and in part through a comparison to peer companies. The analysis of historic net salvage activity considered gross salvage and cost of removal as recorded to the depreciation reserve account Net salvages as a percentage of the cost of plant retired are calculated for each plant component on both annual and three-year moving average bases.

The net salvage percentages estimated is usually determined using the "Traditional Approach" for net salvage estimation. When a utility retires plant, the plant may be: (1) sold to a third party; (2) reused by the utility for additional service; (3) abandoned in place; or (4) physically removed. In the circumstances where the plant is sold or re-used, a salvage proceeds (or positive salvage amount) is normally recognized. In circumstances where the plant is abandoned in place or physically removed, a cost of removal expenditure (or negative salvage) is incurred. The net of these estimated gross salvage proceeds and the estimated costs of removal are expressed as a percentage of the account's original cost to determine a net salvage percentage. In the circumstances where the salvage proceeds exceed the costs of retirement, a net positive salvage percentage exists. In the circumstances where the costs of removal exceed the salvage proceeds, a net negative salvage as a percentage of the original cost is the result.

The estimation of the net salvage as a percentage of original cost as developed using the traditional approach, includes the following five steps.

1. The annual retirement, gross salvage and cost of removal transactions for the period of analysis is extracted from the plant accounting systems.
2. A net salvage amount (gross salvage proceeds less cost of retirement) is calculated for each historic year. Additionally, a net salvage amount is also calculated for each historic three-year rolling band and the most recent five-year rolling band.
3. The net salvage amount determined above is compared to the original booked costs retired for each period in the manner described, which results in a net salvage percentage of original costs retired for each year, in addition to three-year rolling bands and the most recent five-year rolling band. The annual, the three-year rolling average, and the most recent five-year rolling average net salvage percentages are analyzed to determine a reasonable estimated net salvage percentage. At this point the net salvage percentage is based purely upon statistical analysis.
4. Each account is then compared to the net salvage percentage currently approved, compared to peer companies, and discussed with company engineering staff. Based on the statistical analysis, the review of current and peer company net salvage percentages, and with the professional judgment of Concentric, a net salvage percentage is determined for each account.
5. The net salvage percentage is then used in the depreciation rate calculations in the technical update or report.

Appendix D3

FEI AND FBC CASH WORKING CAPITAL LEAD-LAG STUDIES

FortisBC Energy Inc.

Cash Working Capital Lead-Lag Study

March 2019

TABLE OF CONTENTS

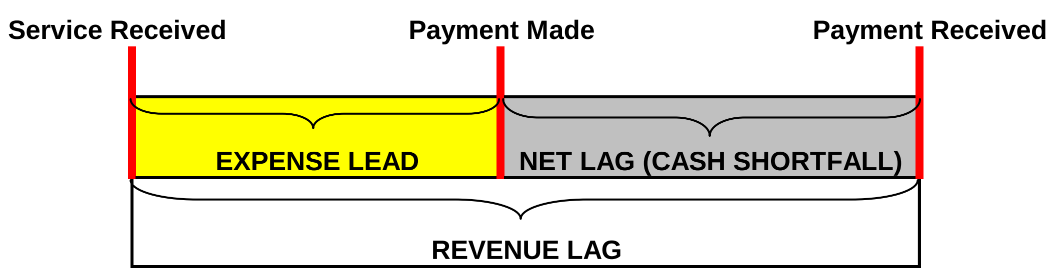
TABLE OF SCHEDULES

TABLE OF LEAD LAG CALCULATION

1 INTRODUCTION

The objective of the Lead-Lag study is to provide a measure of cash working capital needs for FortisBC Energy Inc. ("FEI") in order to support its future working capital submissions before the British Columbia Utilities Commission (BCUC). Cash working capital is defined as the average amount of capital provided by investors in the company, over and above investments in plant and intangibles, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days. The study recognizes that there are timing differences between when FEI provides a service and when they receive payment thereon (**revenue lag**) as well as the time between when they receive a service and subsequently make payment thereon (**expense lead**). The difference between the total revenue lag and total expense lead is the **net lag**. A net lag number greater than zero indicates a cash working capital shortfall position; this occurs when the payment of an expense precedes the collection of its related revenue stream. In some cases, however, revenue may be received prior to payment for the related expense (a net lead or negative net lag), which indicates a cash working capital surplus position. Schedule I-1 illustrates the components of the lead/lag as discussed above.

Schedule I-1 – Lead Lag Schematic Diagram



2 SUMMARY OF KEY FINDINGS

The lead lag days determined in this study will be used for the computation of the cash working capital requirements in FEI's 2020-2024 Multi-year Rate Plan.

Lag days for total revenue and lead days for total expenditures are calculated using 2017 actual data, the most recent year of actual data available to prepare this study. For illustrative purposes within this Appendix and as shown in the table below, the new calculated lag and lead days were then compared to the existing approved lag and lead days and weighted using the 2019 forecasted (approved) revenue and expenditure amounts as a base comparator for each. The change in weighted net lead-lag days was then used to derive the approximate forecasted change in cash working capital included in rate base.

Schedule II-1 summarizes the cash working capital requirements and lead lag days for each significant receipt and expenditure component.

Schedule II-1 – FEI example of change in Cash Working Capital Requirements

Line	Particulars	2019 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days	2019 Forecast (000's $)	Approved Lead Lag Days	Dollar Days
1	**Sales Revenue**						
2	Residential Tariff Revenue	709,672	40.3	28,566,207	709,672	38.3	27,180,438
3	Commercial Tariff Revenue	376,335	37.8	14,216,503	376,335	38.3	14,413,631
4	Industrial Tariff Revenue	92,131	47.7	4,390,990	92,131	45.1	4,155,108
5	Bypass and Special Rates	35,301	37.6	1,326,181	35,301	43.9	1,549,714
6							
7	**Total Sales Revenue**	1,213,439	40.0	48,499,881	1,213,439	39.0	47,298,890
8							
9	**Other Revenues**						
10	Late Payment Charges	2,549	53.8	137,173	2,549	38.3	97,627
11	Connection Charges	1,925	39.0	75,103	1,925	38.3	73,728
12	Other Utility Income	40,419	39.0	1,576,925	40,419	38.3	1,548,048
13							
14	**Total Other Revenues**	44,893	39.9	1,789,200	44,893	38.3	1,719,402
15							
16	**TOTAL REVENUES**	1,258,332	**40.0**	50,289,082	1,258,332	**39.0**	49,018,292
17							
18	Energy Purchases	369,282	40.0	14,770,730	369,282	40.2	14,845,136
19	Operation & Maintenance	246,088	33.2	8,165,077	246,088	25.5	6,275,244
20	Property Taxes	67,559	1.3	84,585	67,559	2.0	135,118
21	Operating Fees	7,851	352.9	2,770,525	7,851	420.3	3,299,775
22	Carbon Tax	273,822	30.7	8,409,712	273,822	29.1	7,968,220
23	GST	10,550	39.7	418,717	10,550	38.8	409,340
24	PST	4,320	45.8	197,659	4,320	37.1	160,272
25	Income Tax	52,972	15.2	805,174	52,972	15.2	805,174
26							
27	**TOTAL EXPENDITURES**	1,032,444	**34.5**	35,622,179	1,032,444	**32.8**	33,898,280
28							
29	**NET LEAD-LAG DAYS (Line 16 - Line 27)**		**5.5**			**6.2**	
30							
31	**CASH WORKING CAPITAL (Line 27/365 x Line 29)**		**$15,557**			**$17,537**	
32							

3 METHODOLOGY AND APPROACH

The methodology used to determine the lead lag days for individual revenue and expenditure items is generally similar for regulated utilities. In addition, the methodology of calculating the lead lag days in this study is consistent with that used in the last study approved by the BCUC in 2009 (Order G-141-09).

The actual data for this lead/lag study is the 2017 calendar year data. This lead/lag analysis takes into account both the working capital requirements associated with lag times as well as the offsetting working capital requirements associated with lead times. Two primary categories of leads and lags were considered: 1) lead times related to the payment for goods and services received by FEI, or *"expense leads"* and 2) lag times related to revenues and the respective collection of those amounts owed to FEI, or *"revenue lags"*.

The two major categories 1) Revenues and 2) Expenses were further broken down into their individual components to obtain the corresponding individual lead/lag times. The results were then rolled up through a weighted average into total lag days for Revenues and total lead days for Expenses. Total lag days for Revenues were then deducted from total lead days for Expenses to arrive at net lag days which were then applied to total expenditures to arrive at Cash Working Capital requirements.

3.1 Calculation of Revenue Lag

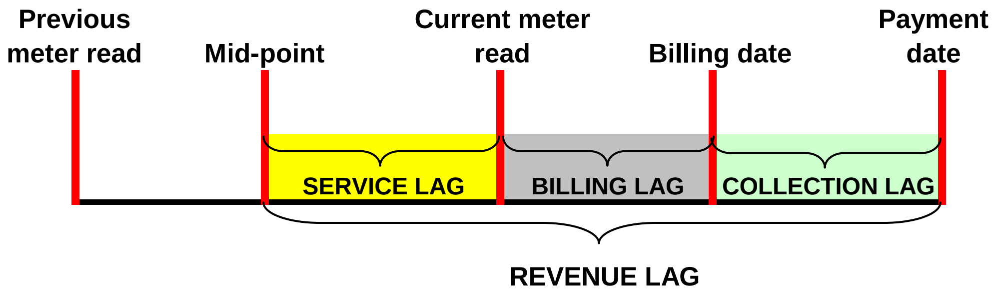
The lag days pertaining to revenue receipts are determined by measuring the elapsed time between the date the service is deemed to be rendered and the date FEI receives the related payments from the customer. The revenue lag is the sum of the service lag, the billing lag and the collection lag.

- The service lag is the number of days from the deemed receipt date of service (generally the mid-point of the cycle) to the meter reading date.

- The billing lag is the number of days between the meter reading date and the billing date.
- The collection lag is the number of days from the billing date to the date the payment is received from the customer.

Schedule III-1 illustrates the components of the revenue lag as discussed above.

Schedule III-1 – Revenue Lag Schematic Diagram



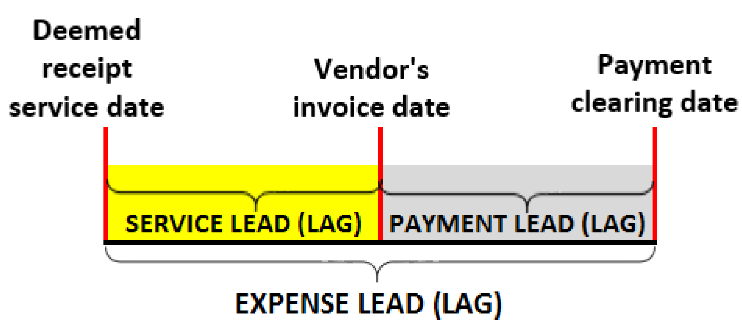
3.2 Calculation of Expense Lead (Lag)

The lead days are determined by measuring the elapsed time from the deemed receipt service date (generally the mid-point) to the date payment is made by the Company. The expense lead (lag) is the sum of the service lead (lag) and the payment lead (lag).

- The service lead (lag) is the number of days from the deemed receipt service date to the vendor's invoice date.
- The payment lead (lag) is the number of days between the vendor's invoice date to the date the funds clear the Company's bank account.

Schedule III-2 illustrates the components of the expense lead (lag) as discussed above.

Schedule III-2 – Expense Lead (Lag) Schematic Diagram



3.3 Calculation of Cash Working Capital Requirements

Once the revenue lags and expense leads (lags) are determined, the calculation of the cash working capital requirement involves the following steps:

- For the individual revenue and expense components, multiply the applicable lead/lag days by the respective forecast revenue and expenditure amount to derive the *dollar days*.
- Divide the total revenue and expenditure dollar days by the total forecast revenues and expenditures to derive *total weighted average revenue lag days and expenditure lead days*.
- Deduct the total weighted average expenditure lead days from the total weighted average revenue lag days to determine the *net weighted average lag days*.
- Multiply total budgeted expenditures by the net weighted average lag days and divide this product by 365 days to determine the ***cash working capital requirement of the Company***.

4 REVENUE LAGS

FEI recognizes two revenue streams: A) Sales Revenues and B) Other Revenues.

4.1 Sales Revenue

The sales revenue lag days for residential, commercial, and industrial customers are derived from the assessment of three time frames:

> *Service Lag* – the time from the deemed average receipt date of service to the average meter reading date
>
> *Billing Lag* – the time from the average meter reading date to the average date the customer is billed, and
>
> *Collection Lag* – the time from the average billing date to the average date the customer pays the bill

4.1.1 Service Lag

The service receipt date is assumed to be the mid-point of the billing period given that customers are expected to receive service evenly throughout the service period. The average days between the deemed service receipt date and meter reading date is 30.4 days, calculated based on 12 billing periods in a 365-day year. When a service is continuous, such as gas sales, the mid-point of the service period is considered the service lag, which would be 15.2 (30.4/2) using the above approach. This is consistent with the approach used in previous studies.

4.1.2 Billing Lag

FEI bills customers (except large industrial customers) on the same day as the gas meter reading date. A separate analysis was necessary for large industrial customers as the average meter reading date differs from the average billing date for this group. The entire large industrial customer population (approximately 11,000 individual customer payment transactions) was analyzed and a weighted average billing lag was determined for FEI large industrial customers.

4.1.3 Collection Lag

For the purposes of the lead/lag study, every customer payment transaction (approximately 11 million invoice records) was analyzed to derive the average collection lag days. FEI bills customers for gas consumption every month. The majority of payments are due 22 days following the invoiced date. All customers do not necessarily pay on the due date.

4.1.4. Summary of Revenue Lag

The following table shows the calculation of the revenue lags by rate class:

Table I-1: Calculation of Sales Revenue Lags

Customer Class	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Residential	15.2	0.0	25.1	40.3
Commercial	15.2	0.0	22.6	37.8
Industrial	15.2	13.8	18.7	47.7
Bypass and Special Rates	15.2	0.0	22.4	37.6

4.2 Other Revenue

Other revenue receipts consist of the following major items:

1. Late Payment Charges
2. Connection Charges
3. Other Utility Income

For FEI, Late Payment Charges are added to the bill that follows after the bill where the late payment occurred, and then that bill is assumed to be collected by the invoice due date. Connection Charges and Other Utility Income are primarily a product of residential and small commercial customers. Hence, the weighted average lag days associated with residential and small commercial revenues were applied to Connection Charges and Other Utility Income.

Table II-1: Calculation of Other Revenue Lags

Other Revenue	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Late Payment Charges	0.0	30.0	23.8	53.8
Connection Charges	15.2	0.0	23.8	39.0
Other Utility Income	15.2	0.0	23.8	39.0

5 EXPENSE LEADS (LAGS)

Expense leads and lags correspond to the lead or lag times associated with the payment for goods and services provided to FEI by its vendors/suppliers.

The expense lead was calculated by analyzing each of FEI's expenses for 2017 to determine the average number of lead days between when a service is received and when payment is made. Accounts Payable transaction detail for all of 2017 was analyzed. Known payment dates and cycles for various recurring expenditures were also utilized. Expense lead times were derived for each of the expense items and then dollar-weighted to produce total weighted average expenditure lead days.

Similar to past Lead Lag studies, eight major groupings of expenses were considered:

- Energy Purchases
- Operations and Maintenance
- Property Taxes
- Operating Fees
- Carbon Tax
- GST
- PST
- Income Tax

Each of these groupings and the associated expense lead or lag times are discussed below.

5.1 Energy Purchases

FEI purchases its gas requirements from numerous vendors. Given that energy purchases comprise the majority of expenditures, each vendor was analyzed in detail. For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date (15.2 days). Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

Table III-1: Calculation of Energy Purchase Leads

Expenditure	Service Lead	Payment Lead	Total Lead Days
	a	b	c=a+b
Energy Purchase	15.2	24.8	40.0

5.2 Operations and Maintenance ("O&M")

To determine the lead days for O&M expenses, these expenses were grouped according to general ledger account.

The primary groupings are comprised of six broad categories: payroll and benefits, contractors, materials, computer costs, insurance and other O&M. The expense lead times related with each category of O&M are discussed in the following section.

Table IV-1: Calculation of O&M Leads (Lags)

	2017 Actual Expenses	Weighting Factor	Service Lead (Lag)	Pyament Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
	a	b	c	d	e=c+d	f=bxe
O&M						
Payroll & Benefits	$ 125,234,010	48%	22.7	10.7	33.3	15.9
Contractors	41,744,237	16%	12.1	37.9	50.0	7.9
Materials	11,348,559	4%	15.2	32.0	47.2	2.0
Computer Costs	15,964,210	6%	42.7	(35.3)	7.3	0.4
Insurance	5,283,487	2%	170.3	(318.0)	(147.8)	(3.0)
Other O&M	31,539,713	12%	15.2	25.8	41.0	4.9
Total O&M Expenses	$ 262,653,928	100%				33.2

5.2.1 Payroll and Benefits

Payroll and Benefits is comprised of a number of expense-related items:

Payroll

There are four different categories of payroll:

- Management & Exempt Employees (M&E)
- Movement of United Professionals (MoveUP)
- International Brotherhood of Electrical Workers (IBEW)
- M&E, MoveUP Part time and Temporary

Depending on the category, each of these has different payment terms and different lead/lag days.

The M&E and MoveUP payroll categories are both based on a biweekly pay period. For this group, actual payment occurs 1 day prior to the end of the biweekly pay period. The total average of 6 lead days is determined by adding the elapsed days from the midpoint to the end of the pay period (service lead of 7 days) and the elapsed days from the end of the pay period to the payment date (payment lag of 1 day).

For the IBEW group, actual payment occurs 7 days subsequent to the end of the biweekly pay period. Thus the service lead is 7 days similar to M&E and MoveUP while the payment lead is 7 days for a total average of 14 lead days.

For the M&E and MoveUP Part Time and Temporary, actual payment occurs 6 days subsequent to the end of the biweekly pay period producing a total average of 13 lead days.

Benefits

Based upon known service periods and specifically recurring payment due dates, lead days are calculated individually for each benefit type:

- Disability Insurance
- Extended Health
- Dental Plans
- Group Life Insurance
- Medical Services Plan/Employer Health Tax
- Workers Compensation
- Employer portion of Canadian Pension Plan
- Employer portion of Employment Insurance
- Pension
- Employee Savings Plan

- Employee Incentive Plans
- OPEB

5.2.2 Contractors, Materials and Computer Costs

Samples of the largest suppliers in each category were analyzed. For goods and services received, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.2.3 Insurance

For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.2.4 Other O&M

The remaining costs not falling into the categories above were analyzed and a dollar weighting of the payment leads were captured. Once again, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.3 Property Tax

FEI makes property tax payments to approximately 150 municipalities within the province of British Columbia. These payments are generally made once a year, with the majority of payments occurring within one or two days of July 2nd. A mid- year approach was used to determine deemed receipt of service while actual payment records were analyzed to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.4 Operating Fees

Operating fees are collected from customers located within municipal boundaries in the Inland, Columbia and Vancouver Island service areas. Fees are collected from customers through the billing system on a monthly basis. These fees are typically remitted to the municipalities in either March or November of the following year[1]. A mid-year approach

[1] *FEI notes that there has been a shift in when payments are remitted to municipalities, such that more payments are now being remitted in March instead of November, which results in a decrease in lead days.*

was used to determine the deemed receipt date of service while actual payment records were examined to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.5 Carbon Tax

Carbon Tax is a tax implemented by the BC Provincial Government on all fossil fuels consumed. Amounts paid are related to both funds collected from customers as well as self-assessed carbon tax amounts. Amounts collected from customers are remitted by the 15th of the month following month of service while self-assessed amounts are remitted at the end of the month following month of service. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

5.6 GST

FEI recovers Canadian Goods and Services tax (GST) paid to suppliers on the purchase of goods and services and remits GST collected on revenues from customers. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

5.7 PST

FEI remits Provincial Sales Tax (PST) collected on revenues from commercial and industrial customers. The Innovative Clean Energy (ICE) Levy, collected from all customers, is related to purchases of electricity, natural gas, fuel oil and propane. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

5.8 Income Tax

An analysis of actual income tax remittances in any given year include both regulated and non-regulated aspects. For the purposes of this lead lag study, only the regulated aspects of taxes paid are considered. Accordingly, an examination of actual remittance records is not considered applicable. The methodology for determining the amount and timing of regulated taxes paid is therefore on a theoretical basis and is in accordance with one of the three accepted methods in the Income Tax Act for calculating monthly instalment payments. One of the accepted methods is to pay to CRA 1/12 of the estimated tax payable for the current tax year at the end of each month of the taxation year. On this basis a mid-month approach is used to determine the receipt date of service while an end of month date is used as payment date.

FortisBC Inc.

Cash Working Capital Lead-Lag Study

March 2019

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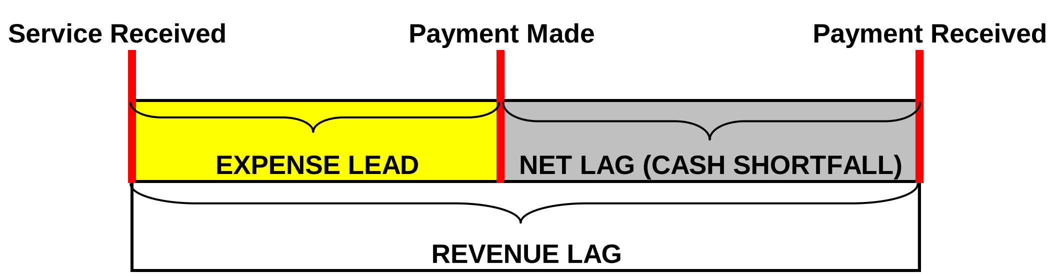
1 INTRODUCTION

The objective of the Lead-Lag study is to provide a measure of cash working capital needs for FortisBC Inc. ("FBC") in order to support its future working capital submissions before the British Columbia Utilities Commission (BCUC). Cash working capital is defined as the average amount of capital provided by investors in the company, over and above investments in plant and intangibles, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The periods are usually expressed in terms of lead or lag days. The study recognizes that there are timing differences between when FBC provides a service and when they receive payment thereon (**revenue lag**) as well as the time between when they receive a service and subsequently make payment thereon (**expense lead**). The difference between the total revenue lag and total expense lead is the **net lag**. A net lag number greater than zero indicates a cash working capital shortfall position; this occurs when the payment of an expense precedes the collection of its related revenue stream. In some cases, however, revenue may be received prior to payment for the related expense (a net lead or negative net lag), which indicates a cash working capital surplus position. Schedule I-1 illustrates the components of the lead/lag as discussed above.

Schedule I-1 – Lead Lag Schematic Diagram



2 SUMMARY OF KEY FINDINGS

The lead lag days determined in this study will be used for the computation of the cash working capital requirements in FBC's 2020-2024 Multi-year Rate Plan.
Lag days for total revenue and lead days for total expenditures are calculated
using 2017 actual data, which is the most recent year of actual data available to prepare this study. For illustrative purposes within this Appendix and as shown in the table below, the new calculated lag and lead days were then compared to the existing approved lag and lead days and weighted using the 2019 forecasted (approved) revenue and expenditure amounts as a base comparator for each. The change in weighted net lead-lag days was then used to derive the approximate forecasted change in cash working capital included in rate base.

Schedule II-1 summarizes the cash working capital requirements and lead lag days for each significant receipt and expenditure component.

Schedule II-1 – FBC example of change in Cash Working Capital Requirements

Line	Particulars	2019 Forecast (000's $)	Proposed Lead Lag Days	Dollar Days	2019 Forecast (000's $)	Approved Lead Lag Days	Dollar Days
1	**Sales Revenue**						
2	Residential Tariff Revenue	187,887	56.0	10,512,442	187,887	50.5	9,488,294
3	Commercial Tariff Revenue	94,508	45.1	4,259,042	94,508	49.4	4,668,695
4	Wholesale Tariff Revenue	49,519	37.5	1,856,662	49,519	33.2	1,644,031
5	Industrial Tariff Revenue	32,414	38.0	1,232,486	32,414	33.2	1,076,145
6	Lighting Tariff Revenue	2,661	34.6	92,030	2,661	50.1	133,316
7	Irrigation Tarrif Revenue	3,544	47.0	166,531	3,544	45.3	160,543
8							
9	**Total Sales Revenue**	370,533	48.9	18,119,194	370,533	46.3	17,171,024
10							
11	**Other Revenues**						
12	Apparatus and Facilities Rental	4,878	90.0	438,868	4,878	27.4	133,657
13	Contract Revenue	1,766	62.2	109,822	1,766	43.6	76,998
14	Transmission Access Revenue	1,230	65.2	80,196	1,230	15.2	18,696
15	Late Payment Charges	861	54.0	46,509	861	90.0	77,490
16	Connection Charge	376	30.5	11,468	376	44.7	16,807
17	Other Recoveries	158	63.4	10,017	158	41.7	6,591
18							
19	**Total Other Revenues**	9,269	75.2	696,880	9,269	35.6	330,239
20							
21	**TOTAL REVENUES**	379,802	**49.5**	18,816,074	379,802	**46.1**	17,501,262
22							
23	Power Purchases	145,065	51.5	7,473,531	145,065	41.7	6,049,211
24	Water Fees	10,465	1.4	15,041	10,465	(1.0)	(10,465)
25	Wheeling	5,235	46.9	245,616	5,235	40.2	210,447
26	Operation & Maintenance	50,321	28.6	1,438,130	50,321	20.3	1,022,894
27	Property Tax	16,713	4.9	81,099	16,713	1.4	23,291
28	GST	8,939	45.4	406,034	-	0.0	-
29	Income Tax	7,806	15.2	118,651	7,806	15.2	118,651
30	Interest Expense			-	40,930	85.2	3,487,236
31							
32	**TOTAL EXPENDITURES**	244,544	**40.0**	9,778,102	276,535	**39.4**	10,901,265
33							
34	**NET LEAD-LAG DAYS (Line 21 - Line 32)**		**9.5**			**6.7**	
35							
36	**CASH WORKING CAPITAL (Line 32/365 x Line 34)**		**6,365**			**5,076**	
37							

3 METHODOLOGY AND APPROACH

The methodology used to determine the lead lag days for individual revenue and expenditure items is generally similar for all regulated utilities. The methodology in this study has been aligned to FEI's current and previous studies. In this study, FBC excludes interest expenses which is consistent with the approach used by FEI, including the last study approved by the BCUC in 2009 (Order G-141-09). FBC also moves GST from the Working Capital Allowance section in the 2019 Annual Review to the Cash Working Capital calculation in this study to align with FEI and calculate the expense lead more accurately than the previous use of monthly average balance. FBC has not made a similar change to the PST line because electricity sales will no longer include PST effective April 1, 2019 and, therefore, it will not be required for future working capital calculations. In addition, FBC uses actual revenue and expenditure data, instead of high-level assumptions used in previously approved studies, which results in more accurate lead lag days.

The actual data for this lead/lag study is the 2017 calendar year data. This lead/lag analysis takes into account both the working capital requirements associated with lag times as well as the offsetting working capital requirements associated with lead times. Two primary categories of leads and lags were considered: 1) lead times related to the payment for goods and services received by FBC, or *"expense leads"* and 2) lag times related to revenues and the respective collection of those amounts owed to FBC, or *"revenue lags".*

The two major categories 1) Revenues and 2) Expenses were further broken down into their individual components to obtain the corresponding individual lead/lag times. The results were then rolled up through a weighted average into total lag days for Revenues and total lead days for Expenses. Total lag days for Revenues were then deducted from total lead days for Expenses to arrive at net lag days, which were then applied to total expenditures to arrive at Cash Working Capital requirements.

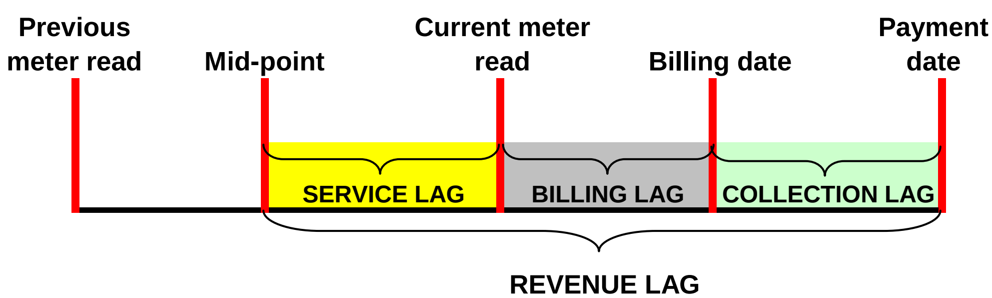
3.1 Calculation of Revenue Lag

The lag days pertaining to revenue receipts are determined by measuring the elapsed time between the date the service is deemed to be rendered and the date FBC receives the related payments from the customer. The revenue lag is the sum of the service lag, the billing lag and the collection lag.

- The service lag is the number of days from the deemed receipt date of service (generally the mid-point of the cycle) to the meter reading date.
- The billing lag is the number of days between the meter reading date and the billing date.
- The collection lag is the number of days from the billing date to the date the payment is received from the customer.

Schedule III-1 illustrates the components of the revenue lag as discussed above.

Schedule III-1 – Revenue Lag Schematic Diagram



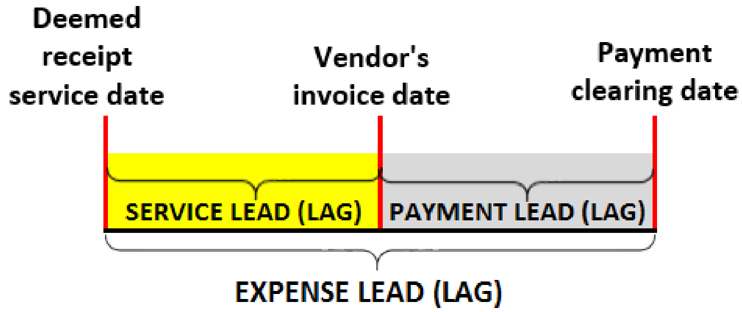
3.2 Calculation of Expense Lead (Lag)

The lead days are determined by measuring the elapsed time from the deemed receipt service date (generally the mid-point) to the date payment is made by the Company. The expense lead (lag) is the sum of the service lead (lag) and the payment lead (lag).

- The service lead (lag) is the number of days from the deemed receipt service date to the vendor's invoice date.
- The payment lead (lag) is the number of days between the vendor's invoice date to the date the funds clear the Company's bank account.

Schedule III-2 illustrates the components of the expense lead (lag) as discussed above.

Schedule III-2 – Expense Lead (Lag) Schematic Diagram



3.3 Calculation of Cash Working Capital Requirements

Once the revenue lags and expense leads (lags) are determined, the calculation of the cash working capital requirement involves the following steps:

- For the individual revenue and expense components, multiply the applicable lead/lag days by the respective forecast revenue and expenditure amount to derive the *dollar days*.
- Divide the total revenue and expenditure dollar days by the total forecast revenues and expenditures to derive *total weighted average revenue lag days and expenditure lead days*.
- Deduct the total weighted average expenditure lead days from the total weighted average revenue lag days to determine the *net weighted average lag days.*
- Multiply total budgeted expenditures by the net weighted average lag days and divide this product by 365 days to determine the ***cash working capital requirement of the Company.***

4 REVENUE LAGS

FBC recognizes two revenue streams: A) Sales Revenue and B) Other Revenues.

4.1 Sales Revenue

The sales revenue lag days for residential, commercial and other customers are derived from the assessment of three timeframes:

A. *Service Lag* – the time from the deemed average receipt date of service to the average meter reading date
B. *Billing Lag* – the time from the average meter reading date to the average date the customer is billed, and
C. *Collection Lag* – the time from the average billing date to the average date the customer pays the bill

4.1.1 Service Lag

The service receipt date is assumed to be the mid-point of the billing period given that customers are expected to receive service evenly throughout the service period. Depending on the billing frequency, the service lag is determined as follows:

- For monthly billings, average days between the deemed service receipt date and meter reading date is 30.4 days, calculated based on 12 billing periods in a 365-day year. When a service is continuous, such as electricity sales, the mid-point of the service period is considered the service lag, which would be 15.2 (30.4/2) using the above approach.
- For bi-monthly billings, average days between the deemed service receipt date and meter reading date is 60.8 days, calculated based on six billing periods in a 365-day year. When a service is continuous, such as electricity sales, the mid-point of the service period is considered the service lag, which would be 30.4 (60.8/2) using the above approach.

4.1.2 Billing Lag

During the test period FBC's customers were billed two days subsequent to the meter reading date. This lag time is built into the average billing lag days calculation for each customer rate category in the residential, commercial and other customer classes.

4.1.3 Collection Lag

For the purposes of the lead/lag study, every customer payment transaction (approximately 1 million invoice records) was analysed to derive the average collection lag days.

FBC bills customers every month or every two months. Payment is due 17 days and 22 days following the invoiced date for monthly and bi-monthly billings respectively. All customers do not necessarily pay on the due date.

4.1.4 Summary of Revenue Lag

The following table shows the calculation of the revenue lags by rate class:

Table I-1: Calculation of Sales Revenue Lags

	Service Period to Meter Read		Proportion Billed		Service	Meter Read to Billing	Billing to Collection		Proportion Billed		Collection	Total
Customer Class	Monthly	Bimonthly	Monthly	Bimonthly	Lag	Billing Lag	Monthly	Bimonthly	Monthly	Bimonthly	Lag	Lag Days
	a	b	c	d	e=a*c+b*d	f	g	h	i=c	j=d	k=g*i+h*j	r=e+f+n
Residential	15.2	30.4	18.4%	81.6%	27.6	2.0	22.2	27.3	18.4%	81.6%	26.3	56.0
Commercial	15.2	30.4	66.7%	33.3%	20.3	2.0	20.9	26.6	66.7%	33.3%	22.8	45.1
Wholesale	15.2	30.4	100.0%	0.0%	15.2	2.0	20.3	0.0	100.0%	0.0%	20.3	37.5
Industrial	15.2	30.4	100.0%	0.0%	15.2	2.0	20.8	0.0	100.0%	0.0%	20.8	38.0
Lighting	15.2	30.4	91.0%	9.0%	16.6	2.0	14.8	28.0	91.0%	9.0%	16.0	34.6
Irrigation	15.2	30.4	62.5%	37.5%	20.9	2.0	21.3	28.8	62.5%	37.5%	24.1	47.0

4.2 Other Revenue

Other revenue receipts consist of the following major items:

1. Apparatus and Facilities Rental
2. Contract Revenue
3. Transmission Access Revenue
4. Late Payment Charges
5. Connection Charge
6. Other Recoveries

The lag days for Other Revenue were calculated separately for each major item using the various individual source data.

Table II-1: Calculation of Other Revenue Lags

Other Revenue	Service Lag	Billing Lag	Collection Lag	Total Lag Days
	a	b	c	d=a+b+c
Apparatus and Facilities Rental	180.1	(119.7)	29.6	90.0
Contract Revenue	15.2	17.0	30.0	62.2
Transmission Access Revenue	15.2	20.0	30.0	65.2
Late Payment Charges	0.0	30.0	24.0	54.0
Connection Charge	11.2	1.5	17.8	30.5
Other Recoveries	15.2	19.3	28.9	63.4

5 EXPENSE LEADS (LAGS)

Expense leads and lags correspond to the lead or lag times associated with the payment for goods and services provided to FBC by its vendors/suppliers.

The expense lead was calculated by analyzing each of FBC's expenses for 2017 to determine the average number of lead days between when a service is received and when payment is made. Accounts Payable transaction detail for all of 2017 was analyzed. Known payment dates and cycles for various recurring expenditures were also utilized. Expense lead times were derived for each of the expense items and then dollar-weighted to produce total weighted average expenditure lead days.

Seven major groupings of expenses were considered:

- Power Purchases
- Water Fees
- Wheeling
- Operations and Maintenance
- Property Taxes
- GST
- Income Tax

Each of these groupings and the associated expense lead or lag times are discussed below.

5.1 Power Purchases, Water Fees and Wheeling

FBC purchases its power, water and wheeling requirements from various vendors, each of which was analyzed in detail. For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

Table III-1: Calculation of Power Purchases Leads (Lags)

Expenditure	2017 Actual Expenses	Weighting Factor	Serive Lead	Payment Lead	Expense Lead	Weighted Expense Lead
	a	b	c	d	e=c+d	f=bxe
Power Purchase	116,917	79%	15.2	35.8	51.0	40.2
Power Purchase - Return on Capital	31,573	21%	182.5	(129.2)	53.3	11.3
	148,490	100%				51.5

Table IV-1: Calculation of Water Fees and Wheeling Purchase Leads (Lags)

Expenditure	Service Lead	Payment Lead	Total Lead Days
Water Fees	182.5	(181.1)	1.4
Wheeling	15.2	31.7	46.9

5.2 Operations and Maintenance ("O&M")

To determine the lead days for O&M expenses, these expenses were grouped according to general ledger account.

The primary groupings are comprised of seven broad categories: payroll and benefits, contractors, rental of T&D facilities, office leases, computer costs, insurance and other O&M. The expense lead times related with each category of O&M are discussed in the following section.

Table V-1: Calculation of O&M Leads (Lags)

	2017 Actual Expenses	Weighting Factor	Service Lead (Lag)	Pyament Lead (Lag)	Expense Lead (Lag)	Weighted Expense Lead (Lag)
	a	b	c	d	e=c+d	f=bxe
O&M						
Payroll & Benefits	23,233	49%	18.8	7.5	26.3	13.0
Contractors	14,100	30%	11.4	29.0	40.4	12.1
Rental of T&D Facilities	3,126	7%	182.5	(127.7)	54.8	3.6
Office Leases	518	1%	15.2	(30.4)	(15.2)	(0.2)
Computer Costs	2,006	4%	41.6	(39.1)	2.5	0.1
Insurance	880	2%	182.5	(342.2)	(159.7)	(3.0)
Other O&M	3,326	7%	15.2	26.7	41.9	3.0
Total O&M Expenses	47,189	100%				28.6

5.2.1 Payroll and Benefits

Payroll

There are four different categories of salaries and wages:

- Management & Exempt Employees (M&E)
- Movement of United Professionals (MoveUP)
- International Brotherhood of Electrical Workers (IBEW)
- M&E, MoveUP Part time and Temporary

Depending on the category, each of these has different payment terms and different lead/lag days.

The M&E and MoveUP payroll categories are both based on a biweekly pay period. For this group, actual payment occurs 1 day prior to the end of the biweekly pay period. The total average of 6 lead days is determined by adding the elapsed days from the midpoint to the end of the pay period (service lead of 7 days) and the elapsed days from the end of the pay period to the payment date (payment lag of 1 day).

For the IBEW group, actual payment occurs 7 days subsequent to the end of the biweekly pay period. Thus the service lead is 7 days similar to M&E and MoveUP while the payment lead is 7 days for a total average of 14 lead days.

For the M&E and MoveUP Part Time and Temporary, actual payment occurs 6 days subsequent to the end of the biweekly pay period producing a total average of 13 lead days.

Benefits

Based upon known service periods and specifically recurring payment due dates, lead days are calculated individually for each benefit type:

- Disability Insurance
- Extended Health

- Dental Plans
- Group Life Insurance
- Medical Services Plan/Employer Health Tax
- Workers Compensation
- Employer portion of Canadian Pension Plan
- Employer portion of Employment Insurance
- Pension
- Employee Savings Plan
- Employee Incentive Plans
- OPEB

5.2.2 Contractors and Computer Costs

Samples of the largest suppliers in both categories were analyzed. For goods and services received, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.2.3 Rental of T&D Facilities, Office Leases and Insurance

For each vendor, the average service lead time was calculated as being the mid-point between service start date and service end date. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.2.4 Other O&M

The remaining costs not falling into the categories above were analyzed and a dollar weighting of the payment leads were captured. Once again, the lead days were calculated from the midpoint of the service period to the date of invoice payment.

5.3 Property Tax

FBC makes property tax payments to approximately 30 municipalities within the province of British Columbia. These payments are generally made once a year, with the majority of payments occurring within one or two days of July 2nd. A mid- year approach was used to determine deemed receipt of service while actual payment records were analyzed to determine the payment lead. Total lead days were calculated as the dollar weighted number of days between deemed receipt of service and payment date.

5.4 GST

FBC recovers Canadian Goods and Services tax (GST) paid to suppliers on the purchase of goods and services and remits GST collected on revenues from customers. A mid-month approach was used to determine receipt date of service while actual remittance records were examined to determine the payment lead.

5.5 Income Tax

An analysis of actual income tax remittances in any given year includes both regulated and non-regulated aspects. For the purposes of this lead lag study, only the regulated aspects of taxes paid are considered. Accordingly, an examination of actual remittance records is not considered applicable. The methodology for determining the amount and timing of regulated taxes paid is therefore on a theoretical basis and is in accordance with one of the three accepted methods in the Income Tax Act for calculating monthly instalment payments. One of the accepted methods is to pay CRA 1/12 of the estimated tax payable for the current tax year at the end of each month of the taxation year. On this basis a mid-month approach is used to determine the receipt date of service while an end of month date is used as payment date.

5.6 Interest Expense

Interest expense is excluded from FBC's lead lag study to apply a consistent approach as that used by FEI and various other utilities in Canada, in which depreciation, interest and equity return are excluded from the lead lag studies and the calculation of Working Capital.

Appendix D4

FEI AND FBC SHARED SERVICES STUDY

FortisBC Energy Inc. and FortisBC Inc.

Appendix D4

Shared Services Study

March 2019

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1. EXECUTIVE SUMMARY

FortisBC completed a review of the Shared Services between FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) at the request of the British Columbia Utilities Commission (BCUC). The review focuses on the nature of the Shared Services between FEI and FBC and to identify an alternate Cost Driver based allocation approach that would simplify the administration of the cost allocation process, while providing an allocation methodology that reasonably represents the sharing of services provided.

Currently, FEI and FBC share resources to meet businesses requirements, which benefits both the companies and the customers they serve. Shared Services in support of operating and maintenance (O&M) activities by function include Customer Service, Operations, Communications and External Relations, Environment, Health and Safety, Information Systems, Operations Support, Fleet Services and support functions Corporate, Finance, Regulatory and Human Resources. Timesheets are used presently to cross charge between the companies for services provided (Timesheet Approach).

Compared to the current Timesheet Approach, a cost driver-based approach to allocate costs by functional area (Cost Driver Approach) is simpler to understand, easier to administer and more efficient, and more stable over time. The cost drivers of the shared services between FEI and FBC are the number of customers of each Company, the number of employees of each Company, the Massachusetts Method, and management estimate of time. Using these cost drivers, the net allocations in aggregate at a Company level between the two companies would be similar to that using the Timesheet Approach. Under a Cost Driver Approach, FEI's 2018 O&M actuals would be reduced by $0.338 million compared to that using the Timesheet Approach with FBC 2018 O&M actuals increasing an equivalent amount of $0.338 million.

Implementation of a Cost Driver Approach to cross-charging between FEI and FBC for Shared Services is recommended for this Multi Year Rate Plan, with adjustments to the allowed O&M Base for both FEI and FBC to reflect the changes in allocations between the two companies that result from adopting a Cost Driver Approach.

2. INTRODUCTION

In the FEI All-Inclusive Code of Conduct and Transfer Pricing Policy proceeding, FEI indicated that it would continue to use the cross charging approach for services between FEI and FBC until it reviewed the feasibility of a Shared Services model approach, and that it anticipating filing the results of its review in an annual review or revenue requirements application. In Appendix A to Order G-25-17, the BCUC agreed this would be appropriate and directed FEI (at page 24) "to file a review of its Shared Services model as part of its 2018 Annual Review under its Performance Based Rate Plan or alternatively, part of its next revenue requirement proceeding." This Shared Services Study is in compliance with this directive.

This study provides an overview of the actual 2018 O&M related Shared Services between FEI and FBC.

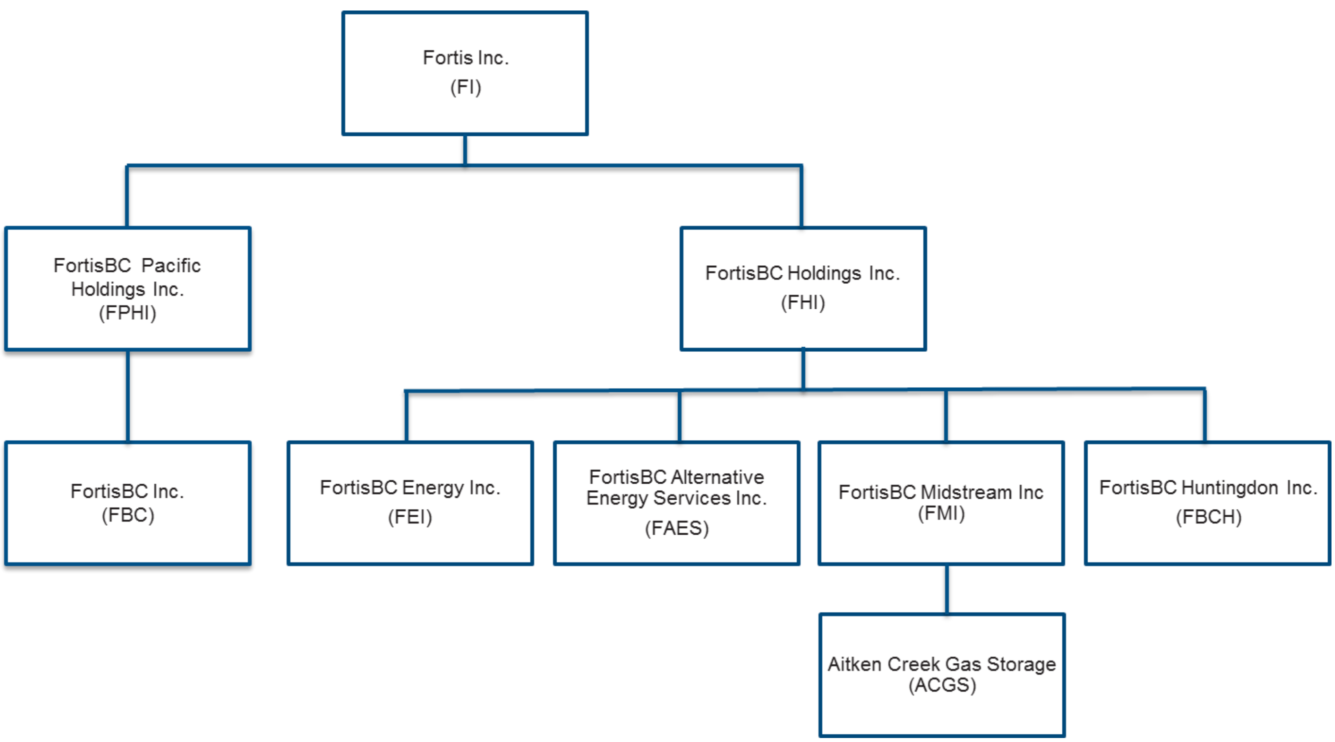
A discussion of the current Timesheet Approach compared to a proposed Cost Driver Approach. The Cost Driver Approach is modelled after and similar to that used successfully for services provided by FEI to FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) during the ten-year period from the time of acquisition until they were amalgamated.

3. BACKGROUND

3.1 *CURRENT ORGANIZATIONAL STRUCTURE*

Figure D4-1 below shows the current (simplified) organization structure of the FortisBC entities and the ultimate parent company, Fortis Inc. The scope of this study is the sharing of services between FBC and FEI.[1] For a description of each entity, refer to Appendix A.

Figure A:D4-1: FortisBC Organizational Structure



[1] For other FEI affiliates, there are existing Shared Services agreements and/or continuing services agreements that address the services provided.

3.2 HISTORY OF SHARING RESOURCES

FEI and FBC began sharing resources in 2010 for the benefit of both companies and their customers, starting with the sharing of the Executive Management Team. Since 2010, the sharing has expanded as the departments in both organizations integrate their operations and processes.

Table A:D4-2 below outlines the level of sharing of resources between FEI and FBC for the years 2013 to 2017.

Table A:D4-1: Capital and O&M Resources Shared between FEI and FBC - 2013 to 2017[2]

	2013 Actuals	2014 Actuals	2015 Actuals	2016 Actuals	2017 Actuals
FEI to FBC					
Labour and Travel expenses	$2,334,000	$3,302,000	$3,421,000	$3,511,000	$4,565,000
Rental of Springfield Road Office	$ 329,000	$ 324,000	$ 324,000	$ 324,000	$ 324,000
Sale of Natural Gas (Tariff Sales)	$ 10,000	$ 11,000	$ 11,000	$ 9,000	$ 14,000
Total	$2,673,000	$3,637,000	$3,756,000	$3,844,000	$4,903,000
FBC to FEI					
Labour and Travel expenses	$3,315,000	$4,498,000	$5,085,000	$5,428,000	$7,012,000
Purchase of Power (Tariff)	$ 576,000	$ 568,000	$ 733,000	$ 733,000	$ 618,000
Total	$3,891,000	$5,066,000	$5,818,000	$6,161,000	$7,630,000

Sources: BCUC Annual Reports

Labour and Travel expenses include the loaded labour dollars (i.e., straight time plus benefits and time-off) and related travel expenses for employees of each organization providing the services.[3] Sharing of labour resources has increased in recent years as integration between Gas and Electric has continued to progress.

Historically, sharing of resources between FEI and FBC, except for Executive Management time allocated using the approved Massachusetts Formula, has been charged between the two companies using the approved cross charge process (i.e., the Timesheet Approach), with the cross charges including fully loaded wages including benefits and time away, with no overhead or a facilities fee assigned. The Timesheet Approach has been appropriate given the early stages of sharing of resources between the two companies and the evolving nature of integration efforts between the Gas and Electric businesses. As the sharing of resources was

[2] 2018 Actuals not available at the time of this report.

[3] Labour and travel costs charged to receiving entity by the providing entity of the services include for activities related to O&M, capital and other (i.e., deferral).

continuing to evolve and not stable, continuing with a Timesheet Approach to recognize the specific circumstances of the resources being shared provided an allocation methodology that reasonably represented the sharing.

In recent years, integration efforts between the Gas and Electric businesses have progressed with oversight and management of Gas and Electric resources shared between the two companies. Common work processes and information technology platforms have been introduced to both organizations to manage businesses requirements. Sharing of resources have grown and stabilized to a point where introducing a Cost Driver Approach will simplify the administration of cost allocations between the two Utilities while providing an allocation methodology that reasonably represents the sharing. The introduction of a Cost Driver Approach to allocate the costs for services provided between FEI and FBC in support of O&M activities is therefore now appropriate.[4] A Cost Driver Approach simplifies the administration of the cost allocation process while providing an allocation methodology that reasonably represents the sharing of services.

3.3 *SCOPE OF SHARED SERVICES*

The common management and integrated approach to managing FEI and FBC supports a Shared Services approach. Shared Services in support of O&M activities by department/function inlcude:[5]

- Corporate
- Customer Service
- Operations Support
- Finance
- Environment, Health and Safety
- Fleet Services
- Human Resources
- Information Systems
- Communications and External Relations
- Regulatory
- Operations

[4] Given their specific nature, costs related to resources provided in support of Capital Projects and Other activities (Deferral – Demand Side Management) will continue to be allocated using the existing timesheet cross charge methodology. Additionally, only labour costs for the Shared Services is subject to the Cost Driver approach as non-labour expenses (i.e., travel expenses) may be charged directly to each company instead.

[5] Excluding Executive Management which are allocated using the approved Massachusetts method. In 2018, the total actual Executive Management costs are $3.9 million with $3.0 million to FEI and $0.9 million to FBC.

Refer to Appendix B for descriptions and details of the Shared Services between FEI and FBC.

3.4 OVERVIEW OF SHARED O&M RESOURCES COSTS

Figures A:D4-2 and A:D4-3 below provide a breakdown of 2018 O&M actuals for FEI and FBC.

Moving from the left to the right in the graphs, the FEI and FBC O&M actuals before cross charges between the two companies are shown (FEI $275.1 million, FBC $58.7 million). The bars that follow show the cross charges in and out of each Company under the existing Timesheet Approach. The value of the resources currently being cross charged between FEI and FBC (excluding Executive Management time) total to approximately $3.9 million for FBC cross charges to FEI and $2.5 million for FEI cross charges to FBC, resulting in a net charge of approximately $1.4 million to FEI. The column "Total O&M Actual" represents FEI and FBC 2018 O&M actuals after cross charges are included (FEI $276.5 million, FBC $57.3 million).

Figure A:D4-2: FEI 2018 O&M Actual Breakdown ($000s)

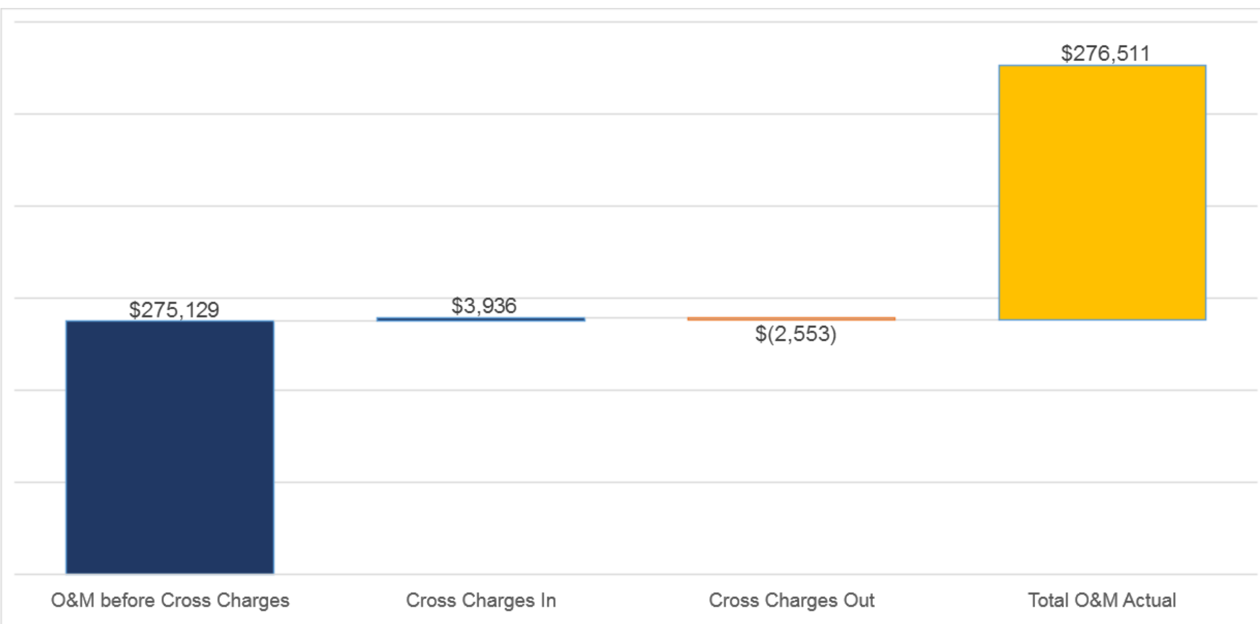
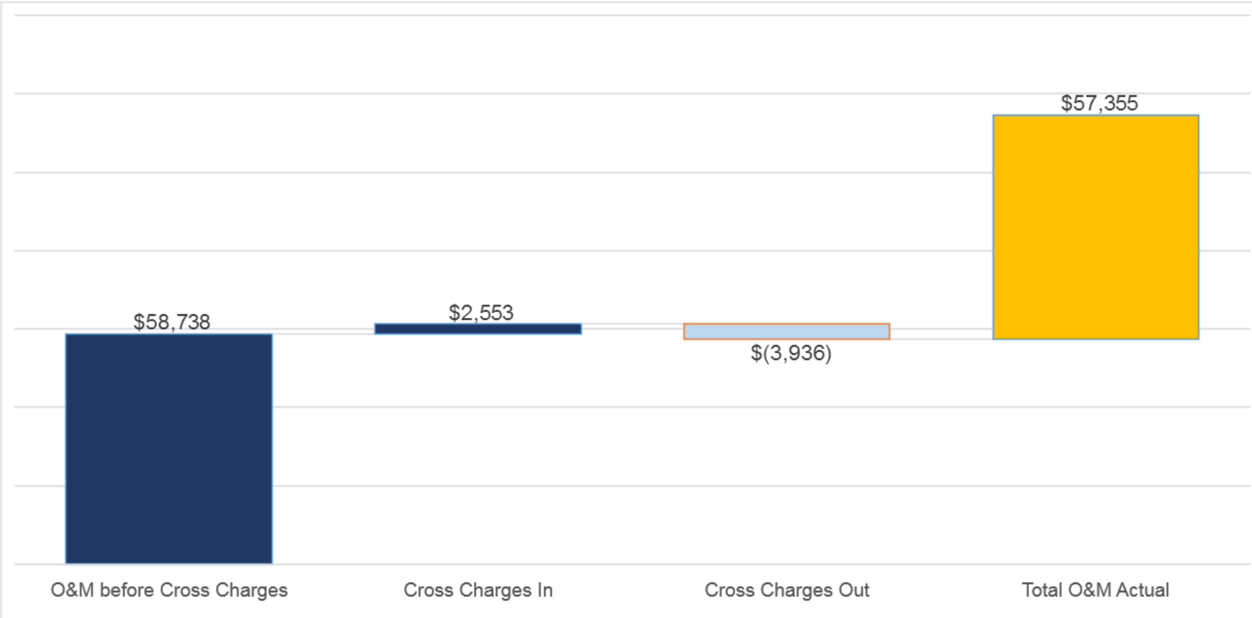


Figure A:D4-3: FBC 2018 O&M Actual Breakdown ($000s)

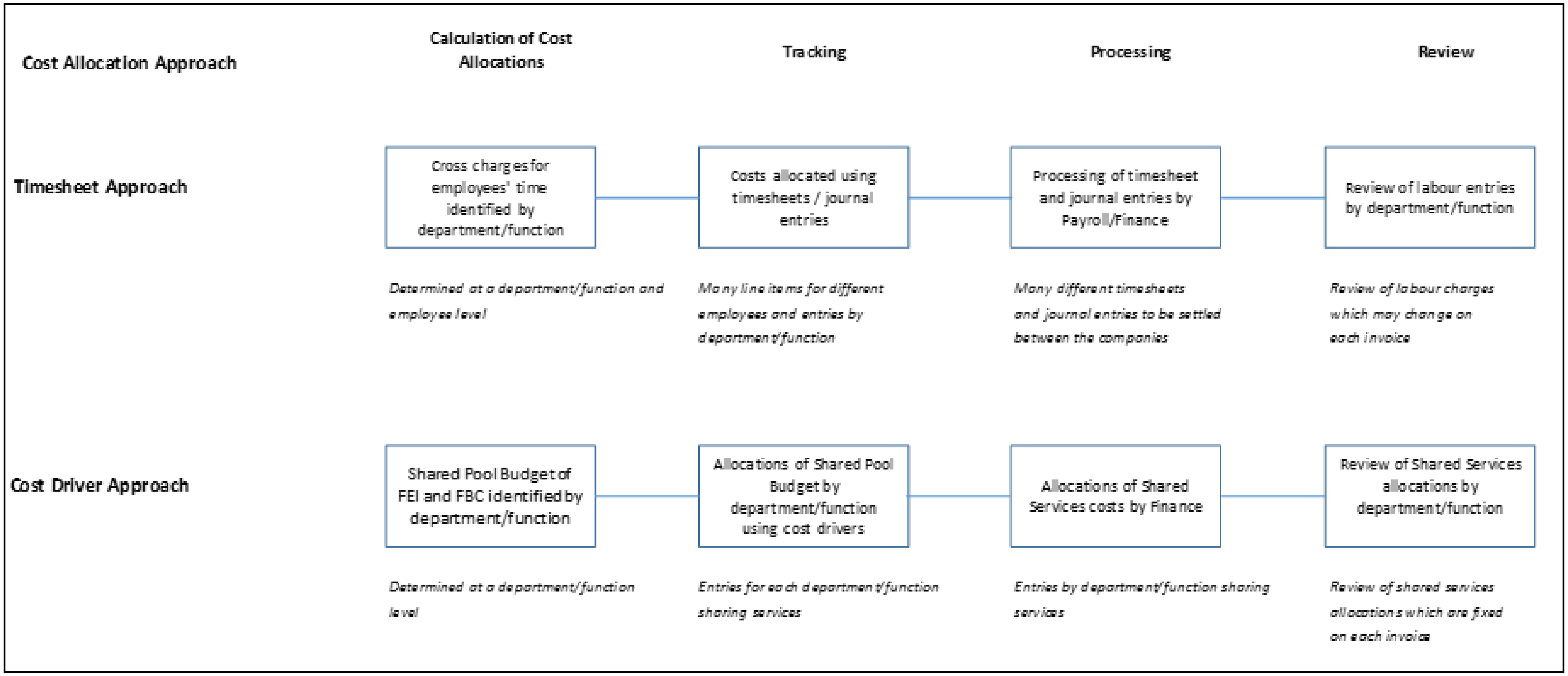


4. APPROACH AND METHODOLOGY

4.1 *OVERVIEW OF TIMESHEET APPROACH VS. COST DRIVER APPROACH*

Figure A:D4-4 provides a comparison of the two approaches from an administration perspective (i.e., calculation of cost allocations, tracking, processing and review). Compared to the Timesheet Approach, the Cost Driver Approach is more efficient to administer while still providing an allocation methodology that reasonably represents the sharing of resources.

Figure A:D4-4: Overview of Timesheet Approach versus Cost Driver Approach



4.2 GUIDING OBJECTIVES

To determine an allocation methodology that reasonably represents the sharing of resources to use, FortisBC referenced previous cost allocation studies completed by KPMG[6] which were approved by the BCUC. Additionally, in the development of the proposed Cost Driver Approach, FortisBC used the following guiding objectives:

- The avoidance of cross subsidization between FEI and FBC;
- The establishment of procedures that are efficient to administer and account for;
- The creation of a methodology that reasonably represents the sharing of resources and is flexible and responsive to organizational changes;
- The demonstration of a causal link between the allocation of costs and the cause of the costs incurred through the use of cost drivers; and
- The use of the allocation driver results in an objective allocation amount that reasonably represents the sharing.

4.3 COST DRIVER APPROACH ALLOCATION METHODOLOGY

A review of departments/functions in FEI and FBC was conducted for Shared Services provided by each Company in support of O&M activities. Interviews were conducted with department/function directors and managers responsible to identify the total 2018 O&M actuals of the departments/functions that were sharing services and the specific resources and associated costs being shared. When using the Cost Driver Approach, the 2018 FEI and FBC O&M actuals first need to be considered using the total actual amounts that would exist in the absence of any sharing (i.e., FEI - $276.511 million - $1.382 million (exclude impact of net cross charges) = $275.129 million; FBC - $57.355 million + $1.382 million (exclude impact of net cross charges (CC)) = $58.737 million). Using the information obtained during the interviews conducted with the department/function directors and managers, the 2018 O&M actuals were adjusted for the costs that were determined to not be shared, leaving the remaining O&M costs to which the Cost Driver Approach is applied to in order to determine the cost allocations.

Table A:D4-2 summarizes this information.

[6] Terasen Gas Inc. Shared Services Cost Allocation Review (June 11, 2009).
FortisBC Inc. and FortisBC Holdings Inc. Corporate Services Cost Allocation Model (June 10, 2013).

Table A:D4-2: FEI and FBC 2018 Cost Driver Approach – Shared Services

000's	2018 Actual w/o CC		Not Shared		Shared	
Function	FEI	FBC	FEI	FBC	FEI	FBC
Shared Service						
Corporate	11,208	2,040	11,208	2,040		
Customer Service	44,559	6,269	36,096	4,855	8,464	1,414
Operations Support	17,193	3,387	16,127	3,284	1,066	103
Finance	9,698	3,795	8,130	2,768	1,568	1,027
Fleet Services	2	298	(314)	7	315	291
Health & Safety	7,340	854	4,180	139	3,160	715
Human Resources	7,828	1,783	3,560	784	4,268	999
Information Systems	22,628	4,854	21,985	4,334	643	520
Communications & External Relations	10,493	1,574	7,352	620	3,141	954
Legal	1,768	486	1,768	486		
Risk Management	5,520	1,369	5,520	1,369		
Regulatory	4,961	801	3,281	487	1,680	313
Gas Operations	131,930	-	130,843	-	1,087	
Electric Opertions	-	31,229	-	30,106		1,123
TOTALS	275,129	58,738	249,737	51,279	25,392	7,459

Within the shared departments/function O&M actuals, the value of the specific resources being shared by the departments (the "Shared Resource Pool Actual") between FEI and FBC total to approximately $33 million (FEI $25.392 million + FBC $7.459 million). Based on the interviews, cost drivers were assigned to allocate the shared O&M costs of those departments/functions between FEI and FBC.

The following is a summary by department of the Shared Services costs and the proposed cost allocation methodologies.

Table A:D4-3: Proposed Cost Allocation Drivers

Function	2018 Identified Shared Costs (1)			Allocation Basis (2)			Allocated Shared Costs (3)			Difference (4)	
	Gas	Electric	Total	Cost driver	Gas	Electric	Gas	Electric	Total	Gas	Electric
Shared Service											
Corporate	-	-	-	Mass. Formula	76.3%	23.7%	-	-	-	-	-
Customer Service	8,464	1,414	9,877	Customers	88.6%	11.4%	8,753	1,125	9,877	289	(289)
Operations Support	1,066	103	1,169	Employees	77.4%	22.6%	904	265	1,169	(162)	162
Finance	1,568	1,027	2,595	Mass. Formula	76.3%	23.7%	1,980	615	2,595	412	(412)
Fleet Services	315	291	607	Time Estimate	52.0%	48.0%	315	291	607	-	-
Health & Safety	3,160	715	3,875	Employees	77.4%	22.6%	2,998	877	3,875	(162)	162
Human Reources	4,268	999	5,267	Employees	77.4%	22.6%	4,074	1,193	5,267	(194)	194
Information Systems	643	520	1,163	Employees	77.4%	22.6%	900	263	1,163	256	(256)
Communications & External Relations	3,141	954	4,095	Employees	77.4%	22.6%	3,168	927	4,095	26	(26)
Regulatory	1,680	313	1,994	Time Estimate	80.0%	20.0%	1,595	399	1,994	(85)	85
Shared Service Total	24,305	6,336	30,642				24,686	5,956	30,642	381	(381)
Operations	1,087	1,123	2,209	Time Estimate	79.2%	20.8%	1,751	459	2,209	664	(664)
Total	25,392	7,459	32,851				26,437	6,414	32,851	1,045	(1,045)

The table above outlines the different departments/functions in FEI and FBC that are sharing resources, with the value of the specific resources being shared in the "Identified Shared Costs (1)" section. The "Allocation Basis (2)" section of the table shows the cost drivers identified.

The cost drivers provide an allocation methodology that reasonably represents the sharing of resources, allocating the Shared Resource Pool Actual of $33 million between FEI and FBC. Applying the cost driver allocation percentages by department/function to the Shared Resource Pool Actual of $33 million, the result is the Shared Resource Pool Actual allocated by department/function for the two companies, as shown in the "Allocated Shared Costs (3)" section.

For comparison, the section of the table identified as "Difference (4)" shows the resulting changes by department/function for each Company's portion of the Shared Resource Pool Actual. Overall, applying the cost drivers, FEI's portion of the Shared Resource Pool Actual increases by $1.045 million from $25.392 million to $26.437 million, with FBC's portion of the Shared Resource Pool Actual decreasing the equivalent amount from $7.459 million to $6.414 million.

The four cost drivers are described below.

- <u>Number of Customers as a Cost Driver:</u> This cost driver allocates the department/function's shared costs for O&M activities to each Company based on the percentage of the total number of FEI and FBC customers. This cost driver is used for most of the Customer Service department costs, excluding the Measurement area in FEI which uses an Estimate of Time, which is appropriate because these costs are driven by the number of customers served.
- <u>Number of Employees as a Cost Driver</u>: This cost driver allocates the department/function's shared costs for O&M activities to each Company based on the percentage of the total number of FEI and FBC employees. This cost driver is used to allocate costs for the Operations Support, Health and Safety, Human Resources, Information Systems and Communications and External Relations departments/functions. The cost driver is appropriate because the costs of these departments/functions are driven by the number of employees.
- <u>Massachusetts Method:</u> The Massachusetts Formula is composed of the arithmetical average of operating revenue, payroll, and the average net book value of capital assets plus inventories. The use of these factors represent the total activity of the different businesses and is used as a means to allocate costs. This cost driver is used to allocate the Corporate and Finance departments/functions' shared costs, which is appropriate as these costs are generally influenced by the size of organization.
- <u>Management Estimate of Time:</u> In some situations, because of the specific nature of the Shared Service being provided, using a numerical based cost driver (i.e., number of customers) would not result in an allocation that reasonably represents the sharing of resources. In these situations, the costs of the Shared Service are allocated based on a management estimate of time. The management estimate of time is used in the Measurement (Customer Service), Fleet Services and Regulatory departments/functions for services shared. For example, in the Regulatory department, resources shared are specific to the circumstances and work such as regulatory filings. In this case, applying

a broad Cost Driver Approach to allocate costs would not provide an allocation methodology that reasonably represents the sharing, as the shared costs are not necessarily driven by the number of employees or customers in each company.

5. COST DRIVER APPROACH ALLOCATION RESULTS

For 2018, under a Cost Driver Approach, FEI would be allocated approximately $26.48 million and FBC would be allocated $6.41 million of the total shared services pool. Compared to the initial resources available for sharing for each Company, $25.39 million FEI and $7.46 million FBC, the net impact of introducing a Cost Driver Approach for allocation of O&M Shared Services between FEI and FBC is $1.04 million higher O&M Shared Services costs for FEI.

6. COMPARISON OF PROPOSED COST DRIVER APPROACH TO CURRENT TIMESHEET

The net effect on each Company's 2018 O&M actual costs of adopting a Cost Driver Approach compared to the existing Timesheet Approach is determined by comparing each company's net 2018 O&M actuals under each approach. Table A:D4-4 shows the companies' existing 2018 overall O&M actuals with the Timesheet Approach cross charges included, and the companies' adjusted overall 2018 O&M actuals, using the proposed Cost Driver Approach for allocations.

Table A:D4-4: Timesheet Approach vs. Cost Driver Approach

FORTISBC - FEI and FBC Shared Services Study Summary $000's															
	Current approach (1)						Cost driver approach (2)							Difference (3)	
Function	2018 actual (a)		Cross charges (b)		2018 actual w/ CC (c)		2018 actual (a)		Allocation (d)			2018 actual after cost driver (e)		Overall Impact	
	Gas	Electric	Gas	Electric	Gas	Electric	Gas	Electric	Cost driver	Gas	Electric	Gas	Electric	Gas	Electric
Shared Service															
Corporate	11,208	2,040	-	-	11,208	2,040	11,208	2,040	Mass. Formula	-	-	11,208	2,040	-	-
Customer Service	44,559	6,269	389	(389)	44,948	5,880	44,559	6,269	Customers	289	(289)	44,848	5,980	(100)	100
Operations Support	17,193	3,387	(107)	107	17,086	3,494	17,193	3,387	Employees	(162)	162	17,031	3,548	(54)	54
Finance	9,698	3,795	337	(337)	10,035	3,458	9,698	3,795	Mass. Formula	412	(412)	10,110	3,383	75	(75)
Fleet Services	2	298	28	(28)	30	270	2	298	Time Estimate	0	-	2	298	(28)	28
Health & Safety	7,340	854	(60)	60	7,280	914	7,340	854	Employees	(162)	162	7,178	1,016	(103)	103
Human Resources	7,828	1,783	(95)	95	7,734	1,878	7,828	1,783	Employees	(194)	194	7,635	1,977	(99)	99
Information Systems	22,628	4,854	263	(263)	22,891	4,591	22,628	4,854	Employees	256	(256)	22,885	4,597	(6)	6
Communications & External Relations	10,493	1,574	132	(132)	10,625	1,442	10,493	1,574	Employees	26	(26)	10,520	1,547	(106)	106
Legal	1,768	486	-	-	1,768	486	1,768	486	Time Estimate	-	-	1,768	486	-	-
Risk Management	5,520	1,369	-	-	5,520	1,369	5,520	1,369	Time Estimate	-	-	5,520	1,369	-	-
Regulatory	4,961	801	(169)	169	4,793	969	4,961	801	Time Estimate	(85)	85	4,876	886	83	(83)
Shared Service Total	143,199	27,509	718	(718)	143,918	26,790	143,199	27,509		381	(381)	143,580	27,128	(338)	338
Operations	131,930	31,229	664	(664)	132,594	30,565	131,930	31,229	Time Estimate	664	(664)	132,594	30,565	0	-
TOTALS	275,129	58,738	1,382	(1,382)	276,511	57,355	275,129	58,738		1,045	(1,045)	276,174	57,693	(338)	338

Notes:

(1) The Current approach starts with department/function 2018 actuals (a) which are adjusted for amounts that will be cross charged in / out as shown in (b). The 2018 actuals next of cross charges are shown in (c).

(2) The Cost Driver Approach starts with the same department/function 2018 actuals (a) which are adjusted for the allocated shared costs (d). The 2018 actuals under the Cost Driver Approach are shown in (e).

(3) The Difference are the resulting changes by department/function for each Company's portion of the Shared Resource Pool Actual as reflected in the last two columns in the table.

As shown in Table A:D4-4, adoption of the Cost Driver Approach provides a similar net allocation for shared O&M services between FEI and FBC, compared to the existing Timesheet Approach (i.e., $0.338 million difference; proposed Cost Driver Approach - $1.045 million net to FEI versus existing Timesheet Approach - $1.382 million net to FEI). While the allocations between the departments/functions may not net out within the departments/functions (i.e., some departments' O&M Shared Services actuals are higher/lower using the Cost Driver Approach compared to the Timesheet Approach), overall at the Company level, the net difference is relatively minor. Consistent with the current Timesheet Approach, the costs allocated between the two Companies include fully loaded wages including benefits and time away, with no overhead or a facilities fee assigned. The main benefit of the Cost Driver Approach is the simplicity of administering and maintaining the cost drivers, requiring only annual updating with a broader review of the Shared Services model on periodic basis.

7. CONCLUSION

Given the difference in the allocations of the two approaches is minimal, FEI recommends adopting the Cost Driver Approach. The Cost Driver Approach is simpler to understand, easier to administer and more efficient, and stable over time using the chosen cost drivers, resulting in more consistent level of allocations from year to year. Updating is required only on an annual basis broader review of the Shared Services model on a periodic basis.

As part of the transition to a Cost Driver Approach in this MRP, an adjustment is required to the Base O&M of FEI and FBC to recognize the difference in overall allocation from the current Timesheet Approach and the Cost Driver Approach. Based on the 2018 actual O&M expenditures, the adjustment required would be an increase to FBC's Base O&M of $0.338 million with an equivalent offsetting reduction to FEI's Base O&M of $0.338 million.

APPENDIX A – FORTISBC AFFILIATES

Aitken Creek Gas Storage ULC (ACGS) – ACGS is a wholly owned subsidiary of FortisBC Midstream Inc. ACGS owns an interest in the underground reservoir and contained natural gas, wells, on-site equipment and other components of the natural gas storage facility at Aitken Creek. ACGS is a public utility subject to an exemption and light-handed regulation by the Commission, due to the fact that it operates in a competitive environment for storage.

FortisBC Alternative Energy Services Inc. (FAES) – FAES is a wholly owned subsidiary of FortisBC Holdings Inc. that provides alternative energy solutions, including thermal-energy and geo-exchange systems. The company specializes in designing, owning, operating and maintaining regulated utility thermal assets to help its clients address deferred maintenance, reduce greenhouse gas emissions, support sustainability objectives and improve the performance of thermal energy systems in buildings.

FortisBC Huntingdon Inc. (FBCH) – FBCH is a wholly owned subsidiary of FortisBC Holdings Inc. The Corporation owns two interconnecting pipelines near Abbotsford, British Columbia which are used in the transmission of natural gas to and from the United states. The Corporation is regulated by the National Energy Board, an independent regulatory authority.

FortisBC Holdings Inc. (FHI) – FHI, a Canadian corporate headquartered in Vancouver, British Columbia, is the parent company of FEI, FAES, FortisBC Midstream Inc and FBCH. A wholly-owned subsidiary of Fortis Inc., FortisBC Holdings Inc., is a holding company. Its subsidiaries are the operating companies.

FortisBC Midstream Inc. (FMI) – FMI is a holding company and the parent company of ACGS.

FortisBC Pacific Holdings Inc. (FPHI) – FPHI is a holding company and the parent company of FBC.

Fortis Inc. (FI) – FI is a holding company and the parent company of FHI and FPHI. FI is a diversified, international holding corporation having investments in distribution, transmission and generation assets and utilities.

APPENDIX B – SHARED SERVICES BETWEEN FEI AND FBC

The following provides a description, by function, of the services shared between FEI and FBC:

a) Corporate. Administration support for the executive leadership team.

b) Customer Service. Customer service includes contact centers, customer and billing operations, measurement services and business innovation. The Shared Services provided to both FEI and FBC include:

a. Overall policy direction and oversight of services relating to Customer Service, which includes customer inquiries, development of customer communication, customer billing, new or altered service requests, revenue protection, credit and collection services;

b. Sharing of contact centre and customer services representatives that assist both gas and electric customers;

c. Market research support, including customer satisfaction surveys;

d. Oversight of outsourced service provider activities including printing and credit and collection;

e. Workforce management and analytical support; and

f. Management of the measurement device fleet which includes the inspection, compliance sampling, sealing and repair of meters and measurement devices.

c) Operations Support. Operations Support is responsible for the Facilities, Property Services, Procurement, Inventory Management and Fabrication. The Shared Services provided to both FEI and FBC include:

Supply Chain

a. Shared management and direction of the Supply Chain teams;

b. Risk mitigation through audit control, terms and conditions for contracts and regulatory compliance; and

c. Shared material purchasing staff.

Facilities

a. Shared management and direction of the Facilities department including continued integration and value added efficiencies;

b. Oversight of all construction, renovation and relocation projects;

c. Ensuring compliance with regulatory requirements and standards; and

d. Physical security for office, warehouse and yard compounds.

<u>Property Services</u>

a. Overall management and direction of the Property Service teams for property taxation, negotiations of land acquisitions, leases, maintenance of right of way agreements and First Nations negotiations; and

b. Property Service responsibilities on large projects.

d) Finance. Finance is responsible for accounting, reporting, financial and business planning, and internal audit. The Shared Services provided to both FEI and FBC include:

a. Shared management, direction, and oversight;

b. Oversee the development and adherence to accounting policies procedures and practices;

c. Accounting for and validation of all financial statement elements including revenues, cost of gas, deferral accounts, financing costs, bank accounts, the accounting for continuing services and the billing of inter-company transactions;

d. Monthly reporting, variance analysis and year-end forecasting;

e. External audit coordination and the preparation of non-consolidated financial statements;

f. Annual and multi-year budget processes;

g. Asset and plant accounting; and

h. Corporate account payable and credit card program.

e) Environment, Health & Safety. Environment, Health & Safety is focused on providing Environment, Health and Safety services to support governance and related business needs of FortisBC. The Shared Services provided to both FEI and FBC include:

a. Management of environmental risks associated with operational activities and compliance requirements with applicable environmental regulation;

b. Manage employee safety risks and compliance with WorkSafeBC regulation;

c. Development of communications plans and strategies of educating customers, first responders, and the general public around properties of natural gas and electricity;

d. Management of emergency management programs and plans that are compliant with all applicable legislation;

e. Business Continuity Planning; and

f. Manage corporate security risk in support of worker and customer safety as aligned with applicable regulation.

f) Fleet Services. Fleet services includes the management of the vehicle fleets for FEI and FBC. The shared services provided to both FEI and FBC include:

a. Vehicle planning and acquisition;

b. Vehicle regulations compliance;

c. Licensing and insurance;

d. Fuel program management;

e. Fleet maintenance management; and

f. Asset disposal services.

g) Human Resources. Human Resources includes workforce planning, hiring practices, labor relations, advisory services, employee development, employee communications and total compensation & benefits programs. The Shared Services provided to both FEI and FBC include:

a. Shared management, direction, and oversight;

b. Ensuring HR direction and programs that affect employees are aligned with departmental and corporate objectives. Areas of responsibility include HR business planning, and compliance with regulatory, and governance reporting;

c. Overseeing the design and delivery of the total compensation and benefits framework to attract, retain and motivate employees. This includes providing recruiting and on-boarding processes to meet business needs and operational requirements, along with supporting the organization with employee communications. Other services include compensation, payroll and time administration, benefits administration, pension administration, recruiting, HR Information Systems and master data, and HR metrics, surveys and reporting;

d. Providing direction and delivery of labor relations and advisory services to maintain and foster productive employee/employment relationships. This includes HR advisory services, disability and attendance management and labor relations but not limited to collective agreement interpretation, administration and collective bargaining; and

e. Designs and delivers employee training and development programs. This includes development and delivery of management training and leadership development.

h) Information Systems. Information Systems department provides both FEI and FBC information technology application and infrastructure management services including:

a. Development of short and long term strategy considering business requirements. This includes the responsibility of planning, forecasting and design of future infrastructure capacity requirements that will support the company's objectives;

b. Identifying, designing, operating, and maintaining the availability, security and integrity of technology and critical enterprise infrastructure including hardware and networks;

c. Management of the costs for the Wide Area Network, including balancing appropriate performance with cost;

d. Overseeing end user technical support for all employees, contractors, applications and associated equipment;

e. Management and monitoring of all telephone contracts, including cellular;

f. Management and costs of all large printing devices for the organization;

g. Life cycle management of technology assets;

h. Maintenance and support of software and databases;

i. Strategy, training, support, and insurance of cyber security for infrastructure and data; and

j. Providing and supporting end user technology such as PCs, mobility devices and video conferencing.

i) Communications and External Relations. Communication and External Relations builds corporate image, protects reputation and mitigates public perceptional risk. The Communications team develops the public information that represents FortisBC to our customers and stakeholders, and External Relations builds relationships with government, First Nations, and B.C. communities in order to effectively engage key stakeholders, and communicate and further our corporate initiatives. The Shared Services provided to both FEI and FBC include:

a. Digital and Social Media support;

b. Media Relations - provide insight into the media, take media calls and connect with media on various topics and issues management on behalf of both gas and electric;

c. Production Services / Customer Communications -- coordinators, designers, specialists, advisors and writers, develop all our communication materials for gas and electric in-house (i.e., advertisements, brochures, videos, digital images, banners, event displays, photography, etc.);

d. Aboriginal relations with first nations regarding our use of the land base and our policies regarding aboriginal engagement by the company;

e. Municipal, Provincial and Federal government relations regarding government policy and ongoing issues such as utility maintenance and construction in municipalities;

f. Project support regarding public consultation for both routine and major projects;

g. Community relations engagement with key groups and leaders in the community to foster good relationships in the support of construction and maintenance of our facilities.

j) Regulatory. Regulatory Affairs assists management in planning and executing work in accordance with the *Utilities Commission Act*, which sets out the mandate of the BCUC and the regulatory framework approved and in place for the Utilities. The Shared Services provided to both FEI and FBC include:

a. High-level policy, strategic, and technical advice and expertise regarding regulatory initiatives and issues as well as the regulatory implications of business initiatives and projects taking into consideration emerging regulatory developments and market trends;

b. Adequate and appropriate regulatory constructs and mechanisms are put in place and maintained for all separate regulated legal entities;

c. Focal point of contact with the BCUC, ensuring the companies are fulfilling their obligations regarding governance of and compliance with regulatory decisions, orders, directives, guidelines, and requirements from the BCUC and government;

d. Adequate and appropriate Tariffs and Rates are in place; and

e. Responsibility to provide financial and accounting analysis, modeling, evaluation, and technical writing in support of the development and review of regulatory applications and filings.

k) **Operations.** Shared management support and Director oversight for operations activities. The Shared Services provided to both FEI and FBC include:

a. Shared management, direction, and oversight of Generation and Engineering services;

b. Energy supply and resource development projects;

c. Long-term resource planning; and

d. Customer energy forecasting requirements

Appendix D5

FI AND FHI CORPORATE SERVICES COST ALLOCATION MODEL REPORT, KPMG

Fortis Inc. and FortisBC Holdings Inc.

Corporate Services Cost Allocation Model

March 8, 2019

Table of Contents

1. Executive Summary

KPMG LLP ("KPMG") was retained by FortisBC Energy Inc. ("FEI") and by FortisBC Inc. ("FBC"), collectively referred to as FortisBC, to perform an independent review of Fortis Inc.'s ("FI" or "Fortis") (see Section 3 for an explanation of the organizational structure) corporate services cost allocation methodology and the reasonableness of the allocated costs of the corporate services provided by FI to FortisBC Holdings Inc. (FHI).

KPMG was also retained to review the corporate services cost allocation methodology and the reasonableness of the allocated costs of the corporate services provided by FHI to FEI and FBC

The basis of the review is to assist FEI and FBC in preparation of their Multi-Year Rate Plan for 2020 through 2024 ("2020 - 2024 MRP Application" or "Application") to the British Columbia Utilities Commission ("BCUC").

KPMG has previously issued a report dated June 10, 2013, on the corporate services cost allocation model used by FHI as part of a rate application to the BCUC.

Specifically, KPMG was engaged to assess:

- Whether the corporate services department cost (or "cost pool") met Management's assessment criteria for shared 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 reasonableness of the allocation methodology and the costs allocated from FI to FHI, and from FHI to FEI and FBC 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 reasonableness of the identified corporate services cost pools through the procedures noted in Section 7, which included:

- Reviewed existing FI and FHI cost allocation methodology documentation, including current corporate services cost pools, process documentation, BCUC correspondence, policy documentation, and peer group models, to the extent possible;
- 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; and

- Obtained details of FI and FHI Management's proposed corporate services cost pools. Identified, 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 KPMG reviewed the roles of individuals within the corporate services cost pools and conducted interviews with relevant FHI, FEI and FBC Management and staff.

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, compared their roles to functional descriptions, employee organizational charts and questionnaires;
- Reconciled corporate services cost pool details to the 2018 budgeted costs provided by Management;
- Discussed organizational changes with Management that may impact corporate services cost pools and assessed if changes to corporate services cost pools, if any, were supported;
- Assessed the final corporate services cost pools against corporate services cost pool principles discussed in Section 4.1 of this report; and
- Discussed with Management the FHI costs directly charged to FBC in 2018 and prior, and assessed the updated corporate services cost allocation methodology and the reasonableness of including FBC in the sharing of corporate services provided by FHI.

KPMG finds the corporate services cost pools for both FI and FHI to be reasonable and additional comments are provided 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 proposed cost allocators to a prior study conducted in 2013 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;
- 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, FEI and FBC allocations are reasonable in nature and amount, and 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 additional comments are provided in Section 7 of this report.

KPMG Conclusion

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 form a reasonable and objective basis for the corporate services cost allocation. KPMG arrived at this conclusion as a result of performing the procedures mentioned above, additional procedures fully described in Section 7, and applying the internal management guiding principle criteria detailed in Section 4.

2. Purpose of Report

2.1 Project Scope

FEI and FBC, collectively referred to as FortisBC, retained KPMG to conduct an evaluation of FI's and FHI's 2018 corporate services cost allocation model in preparation of FortisBC's Multi-Year Rate Plan for 2020 through 2024 ("2020 - 2024 MRP Application" or "Application").

Specifically, KPMG was engaged to assess:

- Whether the corporate services cost pools met Management's assessment criteria for the corporate services cost pools described 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 cost allocation models using the 2018 budgeted amounts as provided by Management.

2.2 Scope Limitations

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

2.2.1 Management responsibility:

FI and FHI'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.

2.2.2 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 engagement does not constitute an audit or review engagement as those terms are defined in CPA Canada literature applicable to the conduct of formal assurance engagements by Chartered Professional Accountants. The data included in this report is as a result of the work KPMG completed and the information provided to us during discussions with FortisBC Management and employees during the course of our work. Explanations and representations provided by FortisBC personnel during the course of our assessment have been considered while preparing this report, but have not been audited or otherwise verified by KPMG.

This Report relies on data and information from these sources and makes no representations with respect to their accuracy or completeness. We have no obligation to update our report or to revise the information contained therein to reflect corrections or changes to information or representations provided to us or other events and transactions occurring subsequent to completion of our fieldwork.

FI and FHI prepared the proposed corporate services cost allocations using 2018 budgeted O&M costs provided by Management. Our findings and conclusions are therefore limited accordingly, and do not assess the reasonableness of such amounts. Also, our findings and conclusions are limited to corporate cost allocations from FI and FHI to FEI, FBC and Aitken Creek Gas Storage Facility ("ACGS").

This report is provided on the basis that it is solely for the information of the management and directors of FortisBC and that it will not be quoted or referred to, in whole or in part, without our prior written consent. KPMG does not accept any liability or responsibility to any third party who may use or place reliance on this Report.

2.3 Report Structure

This report is structured 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, FHI, and FBC.

– **Section 4: Corporate Services Allocation Principles** – Provides assessment criteria that have been internally generated by FortisBC Management to evaluate both costs analyzed and methodologies used.

– **Section 5: Management's Corporate Cost Allocation Model – Fortis Inc. (FI)** - Provides details of the calculation made by Fortis in relation to the corporate services cost pools of FI, the cost allocator(s) applied and the resultant allocation of shared service costs from FI to FHI.

– **Section 6: Management's Corporate Cost Allocation Model – FortisBC Holdings Inc. (FHI)**- Provides details of the calculation made in relation to the corporate services cost pools of FHI, the cost allocator(s) applied and the resulting allocation of shared service costs from FHI to FEI, FBC, and ACGS.

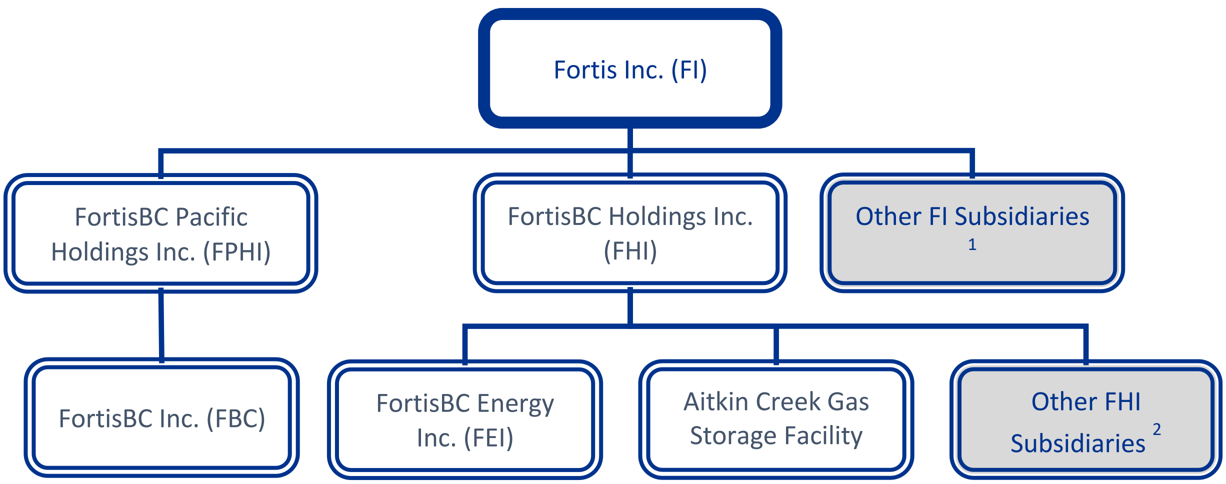
– **Section 7: KPMG Findings** - Provides KPMG's findings from the specified procedures it performed to assess the corporate services cost allocation methodology.

3. Background

FI is traded on the Toronto Stock Exchange ("TSX") and New York Stock Exchange ("NYSE") and is principally an international utility holding company. FI's 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 and FBC.

The following organization chart illustrates FI's relationships to regulated affiliate companies and other subsidiaries.

Figure 4.1: Organizational Chart



1 "Other FI Subsidiaries" include FortisAlberta, Newfoundland Power, Maritime Electric, FortisOntario, Central Hudson Energy, UNS/TEP, ITC, Caribbean Utilities, and Fortis Turks and Caicos.

2 "Other FHI Subsidiaries" include FortisBC Huntingdon Inc., FortisBC Alternative Energy Services Inc., and Inland Energy Pacific Services Inc.

FHI is primarily a utility holding company which provides oversight functions to FEI as well as its other regulated and non-regulated affiliates, including FBC and ACGS, respectively.

FHI is owned directly by FI; FHI provides a number of administrative, accounting and other reporting services to its subsidiaries, including FEI and ACGS, and related party FBC by way of FPHI. FHI has historically utilized a cost allocation model to attribute its shared corporate services operating costs to FEI and ACGS based on a Massachusetts' formula while direct charging to FBC and other FHI subsidiaries. Other FHI active subsidiaries include FortisBC Huntingdon Inc., FortisBC Alternative Energy Services Inc., and Inland Energy Pacific Services Inc.

FEI provides natural gas transmission and distribution services to their customers and obtains the natural gas commodity on behalf of its customers. Pursuant to the Utilities Commission Act (British Columbia), the BCUC regulates such matters as rates, construction and financing for FEI.

FBC, which is indirectly owned by FI, provides electricity transmission and distribution services to its customers, as well as managing electricity generation plants and obtaining electricity on behalf of its customers. Pursuant to the Utilities Commission Act (British Columbia), the BCUC regulates such matters as rates, construction and financing for FBC.

ACGS is a wholly owned subsidiary of FortisBC Midstream Inc. ("FMI"), which is owned directly by FHI (for simplicity, Figure 4.1 does not show FMI in the organization structure between FHI and ACGS). ACGS is a non-regulated entity that provides natural gas storage and optimization service to its customers. FHI provide support to ACGS for certain services similar to those provided to FEI and FBC.

It is common in the utility industry to have a parent company provide services to subsidiaries for many 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 FEI and FBC.

FHI, FEI, and FBC are managed under the same executive leadership team and governed under the same Board of Directors. As a result of this integration, FHI also provides support services to FBC for certain services similar to the services provided to FEI and ACGS. FHI currently direct charges FBC costs incurred for services provided to FBC. For the 2020 - 2024 MRP Application, FHI will rely on a modified cost allocation model that is based on a Massachusetts' formula to attribute its shared corporate services operating costs to FEI, ACGS, and FBC. Specifically, FHI will eliminate the direct charges between FHI and FBC and incorporate the costs currently associated with the direct charges into the FHI corporate service cost pool to be allocated from FHI to FEI, FBC and ACGS using a Massachusetts formula as described in Section 6 of this report.

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, FEI, FBC and ACGS in their cost allocation models. Management has also applied these same criteria in determining their historical corporate services cost pools.

The goods or services must have one or more of the following basic attributes to be included in a corporate services cost pool to be allocated:

- The services performed at FI or FHI provide a direct or indirect benefit to FHI, FEI, FBC, and ACGS, or their respective customer base;

- If the services are no longer provided from FI or FHI, then FHI, FEI, FBC or ACGS, respectively would be negatively impacted and would have to find another source for such good or service or perform such service on its own; or

- The service would be provided by FHI, FEI, FBC, or ACGS, respectively, if they were standalone operations performing their own service, compliance and reporting functions.

4.2 Management's Assessment Criteria for Cost Allocators

Management has developed guiding principles for the corporate service 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 (Table 4.1).

Table 4.1

	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 or is defendable from a regulatory perspective.
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 reliable. 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 structure 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 and FBC collectively, 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 based on the collective asset base of FHI and FBC. The following sections describe in greater detail the components in the model.

Figure 5.1 – FI Cost Allocation Model

5.2 FI Operating Costs

FI's activities are broad and focused on strategic direction, leadership, risk management and oversight of subsidiary companies. Also, FI provides management services to FHI and FBC that enables both subsidiaries 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 regulated 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	– Provides 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	– Manages 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	– Prepares 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 wrongdoing, development of a company-wide Enterprise Risk Management program approach.

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 Including a portion of internal labour costs, and all incremental external expense including but not limited to legal, consulting fees, financial advisory, and travel.
- Costs associated with retired Fortis employees or Fortis employees transferred to an operating subsidiary such as pension-related costs, Performance Share and Restricted Share Unit expenses and any insurance premiums.
- Specific communication and investor relations department costs relating to branding and marketing
- All costs associated with conferences and seminars attended by Fortis Inc. employees, meals and entertainment of Fortis employees and Board of directors, Fortis Inc. employee relocation costs and corporate donations

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, FI management estimates the approximate time spent by the senior executives on shareholder related activity. Consistent with the prior years, Management estimates the following portion of salary and benefits to be excluded from the general cost pool.

- 50% President and CEO
- 50% EVP, CFO
- 50% EVP, Eastern Canadian and Caribbean Operations
- 50% EVP, Western Utility Operations
- 50% VP Treasury and Planning
- 100% EVP, Business Development
- 100% Director, Business Development
- 40% EVP, Chief Legal Officer
- 25% VP, General Counsel – Corporate
- 25% Corporate Counsel
- 60% Director, Regulatory and Compliance and Regulatory Compliance Analysis

- 25% EVP, Chief Human Resources Officer and Corporate Services
- 75% Director Communications and Corporate Affairs and Senior Communications Advisor

The recoverable base salary, related benefits expense, short-term incentives ("STI") and long-term incentives ("LTI") related to EVP, Western Utility Operations is only allocated to FortisBC Energy, FortisBC Electric and FortisAlberta.

The recoverable base salary, related benefits expense STI and LTI related to EVP, Eastern Canadian, and Caribbean Operations, is only allocated to Newfoundland Power, Maritime Electric, FortisOntario, Fortis Turks and Caicos, Belize Electric Company Limited and CUC.

5.4 FHI Proportion of Total Assets and Controllable Costs

The general operating costs incurred by Fortis, less excluded costs or identifiable costs directly allocated to specific operating subsidiaries, are included in a general cost pool and allocated on a pro rata basis to the operating subsidiaries. Following a review conducted by an external consultant in 2017, Fortis uses controllable operating costs as well as total assets (excluding goodwill) to determine the allocation of the general cost pool. The use of multiple factors for general cost allocation is a balanced methodology. The methodology is consistent with the approach used by many utilities, and based on our research is favoured by many regulators. Using multiple factors also recognizes that there is no one perfect allocator, and mitigates the inherent risk associated with using one measure for calculating general cost allocations. To calculate the overall allocation percentage, two cost allocation factors are weighted as follows: (i) 75% to total assets (excluding goodwill), and (ii) 25% to total controllable operating expenses. The weighting for assets recognizes that assets provide the basis upon which regulated utilities earn a return, with total assets (excluding goodwill) closely correlating with the equity investment required of the operating subsidiaries. The weighting for controllable operating expenses recognizes that each subsidiary operates in a substantially autonomous manner, and directly manages certain costs. The use of Assets and Operating Expenses also represents a strong proxy for activity levels at the subsidiaries that are supported by the parent companies.

FHI's portion of FI recoverable cost is calculated based on the weighted average of the FortisBC gas and electric asset allocation (excluding goodwill), and controllable cost allocation as represented in the table below (Table 5.3):

Table 5.3

Allocation Factor	Weighting	Allocation % to FHI
Asset Allocation (Excluding Goodwill)	75%	21.9%
Controllable Cost Allocation	25%	19.9%
Overall Allocation		**21.4%**

The recoverable base salary, related benefits expense, STI and LTI associated with the EVP, Western Utility Operations is only allocated to FortisBC Energy, FortisBC Electric and FortisAlberta. Table 5.4 below shows the FHI's allocation percentage for the EVP, Western Utility Operations.

Table 5.4

EVP West Allocation Factor	Weighting	Allocation % to FHI
Asset Allocation (Excluding Goodwill)	75%	65.6%
Controllable Cost Allocation	25%	70.7%
EVP West Allocation		**66.9%**

General cost allocation include all controlled and majority controlled regulated and non-regulated operating subsidiaries, including the 60% controlling interest in Caribbean Utilities ("CUC"). While costs are allocated to CUC, such allocated costs are not recovered from CUC, as CUC is a publicly listed utility on the TSX. Also, while the non-regulated Waneta hydro generation assets held in the Waneta Expansion Limited Partnership (in which Fortis has a 51% controlling ownership interest) are included in the general cost allocation, such costs are not recovered from the Waneta Expansion Limited Partnership. The same treatment applies to Fortis' non-controlling ownership interests in Belize Electricity Limited and the Wataynikaneyap Power Project.

Using assets and controllable operating expenses in the cost allocation methodology allows Fortis to account for the diversity of operating subsidiaries, which includes transmission and distribution, exclusive transmission, vertically integrated utilities, and natural gas utilities.

Fortis has determined that the use of other cost allocation methodologies, such as total revenue or personnel/payroll, are not appropriate given the diversity of the businesses, the Fortis business operating model and the role of Fortis to provide equity. By way of example, using revenue as a cost allocator may distort the allocation of the recoverable costs as certain utilities, such as FortisAlberta and ITC Holdings, and may only charge customers for distribution services or transmission services, respectively. A revenue-based allocation method would result in a disproportionately low allocation of costs to these two utilities relative to their equity investment requirements. In another example, other operating subsidiaries would receive a disproportionately high allocation of costs in periods when customer rates and related revenue reflect the cost pass-through to customers in times of rising prices for purchased power, gas and fuel. Likewise, using personnel/payroll is not an appropriate cost allocation methodology since the basis of cost recoveries is not on a shared-services model. Such as the case with ITC Holdings, which out-sources a significant component of its required labour, using payroll costs/number of employees as a cost allocation driver would disproportionately allocate lower costs to such utility.

5.5 FHI Portion of FI Recoverable Costs

The general operating costs incurred by Fortis, less excluded costs or identifiable costs directly allocated to specific operating subsidiaries, are included in a general cost pool (Table 5.5) and allocated to FHI based on the overall allocation of 21.4% as shown in Table 5.3 in Section 5.4.

Table 5.5

FI Recoverable Cost Categories	21.4% Allocation of 2018 Forecast to FHI
Salaries	$3,993,593
Directors' fees and costs	726,480
Trustees and DRIP administration	128,109
Consulting	485,009
Legal	703,729
Audit	291,306
Listing and filing	312,094
Annual meeting and report	206,915
Business Development/special projects*	-
Other fees	91,373
Occupancy	320,487
Insurance	223,172
Office related	345,945
Investor Relations	151,225
Communications	61,262
Miscellaneous	10,689
Travel	291,452
Telephone	39,668
Recoverable Amount ($CAD) Excluding EVP, West	**$8,382,508**
* Business Development/special projects remain in FI and were not pushed down to FHI.	

The recoverable amount calculated using the allocation percentage shown in Table 5.4 for the EVP, Western Utility Operations is as follows (Table 5.6):

Table 5.6

EVP, West Allocation	66.9% Allocation of 2018 Forecast to FHI
Recoverable Amount ($CAD) FHI EVP, West Allocation	**$388,923**

The total recoverable amount from FHI including the EVP, Western Utility Operations is the summation of the two amounts represented below in Table 5.7:

Table 5.7

Total FHI and FBC Portion of FI Recoverable Costs	FHI Portion ($CAD)
Total Recoverable Amount ($CAD) Excluding EVP, West	$8,382,508
FHI, EVP West Allocation	388,923
Total FHI Portion of FI Recoverable Costs	**$8,771,431**

6. Management's Corporate Cost Allocation Model – FortisBC Holdings Inc.

6.1 FHI Cost Allocation Model

During the 2014-2019 PBR term, FHI allocated shared services costs to FBC and other subsidiaries through direct charging and allocated shared services costs to FEI and ACGS through a Massachusetts formula approach. For the 2020-2024 MRP application, FHI plans on harmonizing the allocation approach by using a variation of the Massachusetts formula to determine the percentage of operating costs to be allocated from FHI to FEI, FBC, and ACGS.

Through a review of 2018 direct charges from FHI to FBC, it was determined the following FHI departments provides services to FEI, FBC and ACGS:

- Facilities and IT
- External Financial Reporting
- Internal Audit
- Treasury and Financial Planning
- Taxation
- Legal
- Insurance and Risk Management
- Board of Directors

Based on an understanding of the level and type of support that is provided, it is reasonable to conclude that a Massachusetts formula based cost allocation model can be applied to attribute FHI corporate costs to FEI, FBC, and ACGS. This cost allocation approach is consistent with the FI corporate service cost allocation model (see Section 5) used to allocate FI shared services to its subsidiaries. For the 2020-2024 MRP term, FHI proposes to use the Massachusetts formula to allocate FHI corporate services costs to FEI, FBC and, ACGS. The Massachusetts formula based allocation model has been a BCUC approved methodology for allocating these types of costs to stable and mature businesses such as FEI and FBC.

FHI calculates corporate service costs allocation at the department level (e.g., Legal, Internal Audit, and Finance). These cost pools are then allocated to FEI, FBC, and ACGS using a financial composite cost allocator commonly known as the Massachusetts formula, described in Section 6.6 of this report. The following graphic (Figure 6.1) provides a high-level summary of how costs are allocated from FHI to FEI, FBC, and ACGS.

Figure 6.1 FHI Cost Allocation Model

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 FI management fee being charged to FHI, certain amounts are not operating costs that are recoverable from the regulated utilities. As previously determined by the BCUC 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. The specified exclusions of FI management fee and corporate cost to be allocated are presented in Table 6.2.

Table 6.2

	Fortis Inc. Management Fee
Fortis Inc. Management Fee	$8,771,431
(Less) Stock Compensation Costs not Already Excluded by FI	(1,561,000)
Allocation Eligible FI Management Fee	**$7,210,431**

6.3 FHI Operating Expenses

FHI provides management services that enable all related companies to take advantage of the benefits that arise through economies of scale by providing specific services centrally. The services are provided between FHI and the following entities:

– FHI and FEI

– FHI and FBC

– FHI and ACGS

All business services as listed in the cost allocation model are commonly found in gas and electric utilities. FHI's activities are focused on providing fiduciary services to FEI and FBC 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 FortisBC Inc. and FortisBC Energy Inc. 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 are shared between FHI and FBC based on an expanded Massachusetts formula method which incorporates the operating revenue, payroll and average net book value of capital assets plus inventories.
External Financial Reporting	– Preparation of monthly, quarterly and annual consolidated and non-consolidated financial statements, 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, assessing new and existing accounting policy treatments, preparing quarterly forecasts of consolidated earnings and maintaining internal controls over financial reporting.
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.
Insurance & Risk Management	– Ensuring compliance with the TSX requirements on risk management, arranging for coverage based on assessed potential risk, and providing an appropriate and prudent insurance program.

Function	Activities Include
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 &, Financial Planning	– Execute short and long term financings, cash management and forecasting, arrange operating credit facilities, and negotiate bank-service fees for all FEI 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 preparing quarterly financial forecasts
Facilities & Support	– Providing building space, shared services, computer software, computer hardware, 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 FEI and FBC.

6.4 FHI Specified Exclusions

While FHI incurs costs in support of the utilities, some costs are not eligible to be charged to FEI and FBC and have been excluded from the calculation of the FHI management fee. FHI's 2018 recoverable operating cost exclusions are:

- **All identifiable Business Development costs:** 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, Legal, Taxation, and Treasury & Financial Planning 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 has excluded these costs when calculating the fully loaded costs for employees of FHI.

- **Services directly charged to other related entities:** Support services provided by FHI, and directly charged to other regulated and non-regulated entities are excluded in the corporate services cost pools. These exclusions have reduced the costs relating to Legal, Taxation, and Accounting.

6.5 FHI Allocation Eligible Costs

Gross FHI operating costs less the specified exclusions as documented in Section 6.4 equals FHI's costs that are eligible for allocation. Table 6.4 below provides details on the calculation of the allocation eligible costs; the amounts shown are based on 2018 FHI projected costs.

Table 6.4 – FHI 2018 Allocation Eligible Corporate Costs

FHI Corporate Services Cost Pools Eligible for Allocation	FHI Operating Costs	Specified Exclusions	Allocation Eligible Costs
Facilities & IT	$1,167,548	$(53,377)	$1,114,171
External Financial Reporting	797,018	(319,056)	477,962
Internal Audit	1,459,957	(70,000)	1,389,957
Treasury & Cash Management	1,066,259	(258,705)	807,554
Taxation	1,110,112	(204,149)	905,963
Legal	2,051,854	(240,000)	1,811,854
Insurance & Risk Management	273,341	(30,000)	243,341
Board Costs	1,236,410	-	1,236,410
Fortis Inc. Management Fee	8,771,431	(1,561,000)	7,210,431
Total	**$17,933,930**	**$(2,736,287)**	**$15,197,643**

KPMG evaluated the labour and non-labour components of the FHI operating costs and observed the following labour and non-labour components within FHI's operating costs:

FHI Labour Costs

The labour costs include the following personnel classifications:

- Management

- Support staff

The labour costs include the following cost components:

- Base salary

- Bonus
- Employee benefits

FHI Non-Labour Costs

The non-labour costs include the following key components:

- Various external consulting services
- External audit and accounting firm advisory services
- Board of Directors compensation and travel expenses
- Employee training
- Travel, accommodation and meals
- Office supplies
- Professional membership fees
- Legal library
- Computer software and hardware support
- Facilities

The FHI cost components were deemed to be appropriate for use in the Massachusetts' formula based cost allocation method.

6.6 Financial Composite Costs Driver

For all eligible costs, FHI proposes to use a variation of the Massachusetts formula, a financial composite allocator, to determine the percentage of operating costs to be allocated from FHI to FEI, FBC, and ACGS. The Massachusetts formula method 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 the average of:

- Revenues[1]
- Payroll; and
- Average NBV of tangible capital assets plus inventories.

FHI uses Gross Margin in its application of the Massachusetts formula for the following reasons:

[1] FHI uses Gross Margin (revenue less acquisition cost of energy) in place of revenue in its application of the Massachusetts formula

- FEI and FBC do not charge a markup on the commodity price (gas or electricity); therefore gross margin is used to compare the same elements in each utility;
- FEI and FBC do recover revenues on the sale of gas and electricity respectively so any fluctuations in the underlying commodity price are reflected in revenue and therefore 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 or electricity 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 6.5 provides a summary of the cost allocator results that are consistent with Management's assessment principles in Section 4 of this report.

Table 6.5 – Financial Composite Formula Calculation as at December 31, 2017

	FEI	FBC	ACGS	FEI, FBC & ACGS Total
Gross Margin	$787,292,477	$217,649,059	$53,662,429	$1,058,603,964
	74.37%	20.56%	5.07%	100%
Payroll	$132,954,038	$46,290,792	$5,632,083	$184,876,913
	71.91%	25.04%	3.05%	100.0%
Average of NBV of PP&E + inventories	$4,361,337,041	$1,314,337,021	$444,647,627	$6,121,321,689
	71.26%	21.47%	7.27%	100%
Massachusetts Formula Allocation	**72.51%**	**22.36%**	**5.13%**	**100%**

6.7 Portion of FHI Recoverable Operating Costs

After exclusions and the application of the revenues stated in Table 6.4 above and the allocation percentages for each entity as indicated in Table 6.5, the net costs to be allocated to FEI, FBC and ACGS are shown in Table 6.6 below.

Table 6.6 – 2018 FHI Operating Costs and FI Management Fee Allocation

	Allocation Eligible Costs	FEI (72.51%)	FBC (22.36%)	ACGS (5.13%)
Facilities & IT	$1,114,171	$807,944	$249,105	$57,122
External Financial Reporting	477,962	346,595	106,862	24,505
Internal Audit	1,389,957	1,007,930	310,765	71,262
Treasury and Financial Planning	807,554	585,600	180,552	41,402
Taxation	905,963	656,961	202,554	46,448
Legal	1,811,854	1,313,870	405,092	92,892
Insurance & Risk management	243,341	176,459	54,406	12,476
Board Costs	1,236,410	896,585	276,435	63,390
Fortis Inc. Management Fee	7,210,431	5,228,660	1,612,101	369,670
Total	**$15,197,643**	**$11,020,604**	**$3,397,872**	**$779,167**

7. KPMG Findings

7.1 Summary

Following the approach described in Section 7.2, procedures detailed in Section 7.3, and allocation guiding principles documented in Section 4, 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 are reasonable and objective.

7.2 Approach

This section summarizes KPMG's approach to conducting our evaluation of FI and FHI's corporate services cost allocation methodology using 2018 data.

Our work plan incorporated the following phases:

- **Phase 1: Launch.** In this phase, KPMG obtained FI and FHI's 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, BCUC correspondence, policy documentation, and peer group models, to the extent possible;
  - Reviewed the historical 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 functional descriptions of individuals within the corporate services cost pools and conducted interviews with relevant 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 FEI and should be included in the corporate services cost pools;
  - Reviewed corporate services cost pools, including labour and 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 and confirmed with Management the financial impact to cost pools in changing from a direct charge model for FBC to a Massachusetts Formula allocation approach;
  - Reviewed personnel assigned to corporate services cost pools and enquired of Management if other individuals are associated with services benefiting FBC, FHI, and FEI; and
  - 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: Conducted Stakeholder interviews.** In this phase, KPMG performed the following:
  - Prepared survey questions with corporate services stakeholders for phase 2 discovery validation including the following insights:
    i. Role description and activities of the stakeholder's department.
    ii. Cost drivers determination
    iii. Cost centre budget
    iv. FTE count and resourcing information
    v. Management estimate of effort allocation
- **Phase 4: Review Allocation Methodologies and Cost Allocators.** In this phase, KPMG performed the following:
  - Compared the cost allocator(s) to available historical cost allocators;
  - Evaluated the appropriateness of each cost allocator for allocation of cost pool expenditures against internal cost allocator principles (included in Section 4 of this report), including identification of options (where applicable), and their pros and cons;
  - Discussed with Management new cost allocators for non-labour related components of corporate services cost pools, the pros and cons of the recommended changes; and
  - Assessed Management's final cost allocators and assessed Management's resulting revised allocations, if any, for reasonableness.
- **Phase 5: Validate cost pools and cost allocators and methodology.** In this phase, KPMG performed the following:
  - Reconciled cost pools details to FI and FHI's 2018 budget figures from Management.
  - For a sample of individuals in each cost pools, agree their roles to functional descriptions or employee organizational charts;
  - Validated the mathematical accuracy of cost allocations and ensured that the allocators are consistent with the allocators noted in Phase 3;
  - 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 FEI cost allocation was reasonable when compared to the principles in Section 4 of this report; and
  - Discussed with Management initial findings and alternative methods of corporate cost allocation methodology.
- **Phase 6: 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 FEI.

Table 7.1

Procedure	Findings - Management's Share Cost Allocation Model Fortis Inc. (FI)	Findings - Management's Share Cost Allocation Model FortisBC Holdings Inc. (FHI)
7.3.1 Cost Pools		
1. Obtained existing cost allocation methodology documentation, including current corporate services cost pools, process documentation, BCUC 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. 2013 report did not include comments on FBC allocation. Therefore no historic allocation model comparison was conducted for FBC in this study.	Completed. The cost allocation pools based on the proposed Massachusetts Formula approach was compared with the historical hybrid direct charge and formulaic allocation approach. The cost pools are consistent with historical cost allocation pools.
3. Obtained and discussed with Management its guiding principles for identifying appropriate corporate services cost pools	Completed. Section 4 of this report discussed the report's guiding principles. Final proposed corporate services cost pools were concluded to be consistent with those principles.	Completed. Section 4 of this report discussed the report's guiding principles. 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 KPMG 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 FEI and should be included in the corporate services cost pools.	Completed. FI financial results were presented in summary form.	Completed. Costs that were previously direct charged to FBC were included in the new cost pools.
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. FI financial results were presented in summary form.	Completed. Costs that were previously direct charged to FBC were included in the new cost pools.
7. Reviewed personnel assigned to corporate services cost pools and enquired of Management if other individuals are associated with services benefiting FHI, FEI, and FBC respectively.	Completed. No additional individuals were noted.	Completed. No additional individuals were noted.
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 The changes to the FHI cost pools were supported by financial data provided by Management.
7.3.2 Cost Allocators and Cost Allocation Methodology		
1. Compared the cost allocator(s) to historical cost allocators.	Completed	Completed.

<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">

Evaluation Criteria	Assessment of total assets	Assessment of Massachusetts Formula
Cost Causality	S	S
Objective Results	S	S
Cost-Effectiveness	S	S
Stability over time	S	S
Transparent and Supportable Methodology	S	S
Regulatory Precedence	S	S
Distinguishable from Directly Allocated Costs	S	S
Accuracy of Underlying Data	SS*	S
Flexibility / Adaptability	S	S

* This Report relies on data and information provided by FortisBC and KPMG makes no representations with respect to their accuracy or completeness.

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</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	N/A – FI employees are not required to complete timesheets.	N/A – FHI employees are not required to complete timesheets.
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;	KPMG reviewed FI documentation on time estimates for employees and noted the allocated percentages are clearly documented and did not significantly differ from the time allocation results based on historical time allocators.	KPMG reviewed 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.
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. Discussed alternate cost allocators with Management and the pros and cons of the recommended changes.	N/A.	KPMG reviewed the proposed Massachusetts formula based composite cost allocation method and discussed with Management the relative merits of this approach with the historical approach of using the direct charging plus Massachusetts Formula. The allocation differences between the methodology in this study and the one approved for 2014-2019 PBR are calculated to be less than 1% to the overall O&M of either FEI or FBC.
3. Obtain from Management, back-up documentation 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 2018 FHI and FEI budget. 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. Validation carried out on summary data provided.	Completed. No issues noted. See the resulting allocations in Table 6.6.

7.4 KPMG Conclusion – Corporate Services Cost Allocation

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 form a reasonable and objective basis of the corporate services cost allocation. KPMG arrived at this conclusion as a result of performing the procedures contained in this report, and applying the internal management guiding principle criteria detailed in Section 4.

At KPMG,
our values create
a sense of shared
identity. They define
what we stand for
and how we do things.

Our values help us
to work together in
the most effective
and fulfilling way.
They bring us
closer as a
global organization.

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Appendix D6

CAPITALIZED OVERHEAD STUDIES

Appendix D6-1

FEI OVERHEAD CAPITALIZATION METHODOLOGY REVIEW, KPMG

KPMG

FortisBC Energy Inc.

Overhead Capitalization Methodology Review

March 8, 2019

Table of Contents

1. Executive Summary

KPMG LLP ("KPMG") was retained by FortisBC Energy Inc. ("FEI") to assist with their overhead capitalization study (the "Study") to be incorporated in FEI's 2020 to 2024 Multi-Year Rate Plan ("MRP"). The purpose of the Study is to review the overhead capitalization methodology and resulting overhead capitalization rate of FEI under U.S. Generally Accepted Accounting Principles ("U.S. GAAP"), including the application of regulatory accounting, in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 ("ASC 980") *Regulated Operations*. The "overhead capitalization rate" is defined by FEI as the percentage of Gross Operations and Maintenance ("O&M") costs, related to capital activity, which have not been directly charged to capital.

Commencing with the accounting period beginning January 1, 2012, FEI has been approved to apply U.S. GAAP pursuant to British Columbia Utilities Commission ("BCUC") Order G-117-11. This framework includes the application of ASC 980 *Regulated Operations*. Accordingly, the scope of this report is to provide a review of capital overhead cost allocation methodology and resulting overhead capitalization rate of FEI under the U.S. GAAP financial reporting framework. BCUC has previously confirmed that FEI is required to have the capitalized overhead study prepared under U.S. GAAP with consideration of ASC 980.

The basis of this Study is the 2018 FEI BCUC approved O&M costs. In the absence of future significant regulatory, capital, accounting and organizational changes, the application of this rate in future periods is expected to continue to be appropriate.

No single regulatory guideline, statement or source exists that is universally accepted by utilities and regulators as the definitive statement, definition or standard that prescribes the types of indirect costs (i.e. those related to capital projects that have not been directly charged to those capital projects), that should be considered for capitalization for purposes of regulatory and financial reporting. There is limited guidance both from regulators and in U.S. GAAP in this area. Therefore, variations in practice exist due to the limitations of the available framework and the capitalization policies approved by the relevant utilities' regulator. Nonetheless, this topic has been the subject of discussion and comment and a body of guidance exists on the topic. From this guidance, 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 are as follows:

In order to provide an objective and reasonable basis of determining overhead capitalization, FEI undertook a capital cost allocation study using a Survey-based Model. The Study utilized FEI's BCUC approved 2018 FEI O&M (the "2018 O&M") figures. The O&M costs which are allocated to capital through the overhead capitalization rate are net of costs directly charged to capital projects.

KPMG finds the FEI Survey-based capital cost allocation methodology, as detailed in Section 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities that have not been directly charged to capital projects (i.e. overhead capitalization). This methodology is consistent with internally generated evaluation criteria and practice established by the external guidance (referred to in this report), in particular the requirements of U.S. GAAP under ASC 980 *Regulated Operations*.

Based on the Survey-based methodology applied by FEI, and using the 2018 O&M figures, the costs related to capital activities that have not been directly charged to capital projects, as a percentage of total 2018 O&M cost, is estimated to be approximately **16 percent**. This result is observed to be in line with FEI's increased level of capital activities since the last study was completed in 2013 (12%).

In the absence of future significant regulatory, capital, accounting and organizational changes, the application of this rate in future periods is expected to continue to be appropriate.

2. Purpose of Report

2.1 Project Scope

KPMG was retained by FortisBC Energy Inc. ("FEI") to assist with their overhead capitalization study (the "Study") to be incorporated in FEI's 2020 to 2024 Multi-Year Rate Plan ("MRP"). The purpose of the Study is to review the overhead capitalization methodology and resulting overhead capitalization rate of FEI under U.S. Generally Accepted Accounting Principles ("U.S. GAAP"), including the application of regulatory accounting, in accordance with Financial Accounting Standards Board Accounting Standards Codification 980 ("ASC 980") *Regulated Operations*. The "overhead capitalization rate" is defined by FEI as the percentage of Gross Operations and Maintenance ("O&M") costs, related to capital activity, which have not been directly charged to capital.

This report examines the appropriateness of the capitalization of capital overhead costs which have not been directly charged to capital. Within the context of the study, it is important to note that capitalized overhead costs should be distinguished from costs charged directly to capital. These are costs that are charged directly to specific identified capital projects and therefore form part of the direct capital cost of the associated assets. Such costs include the costs of materials and construction labour, as well as any purchased services (e.g. outside contracting) that may be associated with installation or construction of the asset. Such direct charges are removed from the costs which are to be allocated to overhead under the Survey-based Model below. That is, the O&M costs which are allocated to capital are allocated net of the direct charges.

"Capitalized overhead," in contrast, reflects those costs that relate to capital projects but that have not been specifically identified with or charged directly to any individual capital project.

Costs associated with capital activities not directly charged to capital projects are capitalized on the basis of predetermined rates established by management upon review and approval by the BCUC. The methodology used by management to determine these rates is developed to ensure a reasonable allocation of capital related O&M costs to capitalized activities.

2.2 Accounting frameworks

Commencing with the accounting period begining January 1, 2012, FEI has been approved to apply U.S. GAAP pursuant to BCUC Order G-117-11. This framework includes the application of ASC 980 *Regulated Operations*. Accordingly, the scope of this report is to provide a review of capital overhead cost allocation methodology and resulting overhead capitalization rate of FEI under the U.S. GAAP financial reporting framework. BCUC has previously confirmed that the FEI is required to have the capitalized overhead study prepared under U.S. GAAP with consideration of ASC 980[1].

[1] Per Commission filed letter, Log No. 41870.

The basis of this Study is the 2018 FEI BCUC approved O&M costs. In the absence of future significant regulatory, capital, accounting and organizational changes, the application of this rate in future periods is expected to continue to be appropriate.

In summary, this report:

- Addresses the accounting policies under the U.S. GAAP framework followed by FEI;
- Reviews the capital overhead cost allocation methodology applied by FEI;
- Assesses the reasonableness of the activities allocated to capital;
- Assesses the reasonableness of the cost drivers; and
- Presents the resulting overhead capitalization rate.

2.3 Scope Limitations

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

2.3.1 Management Responsibility

FEI's capitalization methodology report is the responsibility of management who also maintain responsibility for the accuracy and completeness of the data and information associated with the capital cost allocation methodology and associated costs.

2.3.2 KPMG Engagement

Our engagement is to comment on the reasonableness of the capital overhead cost allocation methodology, in the context of FEI's reporting under U.S. GAAP, inclusive of ASC 980, and undertake the steps outlined in Section 5 of this report.

This evaluation does not constitute an audit of the capital overhead cost allocation methodology, associated costs or the resulting capitalization rate. Accordingly, we do not express an opinion on such matters. For the avoidance of doubt, KPMG has neither audited nor reviewed the underlying fiscal 2018 BCUC approved O&M costs that form the basis of the percentages capitalized in FEI's Study. However we have outlined the steps undertaken to assess the reasonableness of the underlying data in Sections 5 and 7.5.

KPMG assessed the proposed capital cost allocation methodology using fiscal 2018 BCUC approved O&M costs, as provided by management. Our findings and conclusions are therefore limited accordingly.

The information contained herein is for the internal use of FortisBC management. It is understood that this report will be distributed by FortisBC externally to the BCUC as part of the regulatory process. 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 Gas Utilities* and Federal Energy and Regulatory Commission's ("FERC") *Uniform System of Accounts.*

Section 5: **KPMG Approach** - Provides an explanation of KPMG's approach to assessing FEI's capital cost allocation methodology including the criteria used by KPMG during our analysis. This scope of the evaluation was agreed between KPMG and FEI and the evaluation approach is based on KPMG's past practice of similar capital cost allocation methodology studies undertaken by other Canadian utility companies.

Section 6: FEI Overhead Capitalization Methodology and Results - Provides a high level summary of the components of the overhead capitalization methodology.

Section 7: KPMG Evaluation - Provides KPMG's findings as to the reasonableness of the capital cost allocation methodology.

Appendices:

- **Appendix A** - Capitalized overhead survey
- **Appendix B** - Detailed listing of Accounting Guidance

3. Background

3.1 Application of U.S. GAAP

FEI 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). On July 3, 2014, BCUC approved the continued adoption of U.S. GAAP for regulatory accounting effective January 1, 2015 until FortisBC no longer has an Ontario Securities Commission exemption to use U.S. GAAP or is no longer reporting under U.S. GAAP for financial reporting purposes, whichever is earliest (pursuant to Commission Order G-83-14).

3.2 Previous Capital Overhead Rate Submissions

KPMG previously issued to FEI a report dated June 10, 2013 on the overhead capitalization methodology in support of the Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 ("the 2014-2018 PBR"). That 2013 study report was prepared under the U.S. GAAP framework and recommended an overhead capitalization rate as a percentage of total O&M costs of approximately 12% for FEI based on Survey model approach. BCUC directed FEI to use the 12% overhead capitalization rate for the 2014-2018 PBR.

4. Financial accounting framework

4.1 FEI Capitalization Policy

FEI follows the available U.S. and regulatory accounting guidance. FEI applies the accounting guidance following a hierarchy based model. This hierarchy is as follows:

– Utilize available U.S. GAAP guidance, including ASC 980 (discussed in Section 4.2);

– Utilize available guidance from BCUC *Uniform System of Accounts Prescribed for Gas Utilities* (discussed in Section 4.3); and

– 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.

4.2.1 Available Regulatory Guidance

The ability to capitalize costs under ASC 980 is dependent on the actions of the regulator. With respect to the capitalization of overhead, the BCUC's *Uniform System of Accounts Prescribed for Gas Utilities* provides a basis of reference as 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 guidance exists on the topic. From this guidance, 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 FEI adopts should apply this basic principle.

4.3 Summary

Due to the absence of detailed guidance for each and every type of capital activity in U.S. GAAP, there is a degree of interpretation required in the application of the standards. As a result, the common principle and underlying methodologies employed by FEI for capitalizing costs related to capital activities that have not been directly charged to capital projects reflects a consistent approach under 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.

There has been no changes to the guidance reviewed in this section for 2018.

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 the survey approach used to evaluate the capitalization of overhead, including the formulation of questions used in the survey approach as discussed further in Section 6. We reviewed supporting documentation and previous relevant regulatory filings to gain a better understanding of the previous approaches adopted to capitalizing costs to capital activities.

Step 2: Participated in interviews with company officials. In this step KPMG participated in various interviews held by FEI with senior representatives from the operating areas. The purpose of this step was to gain an understanding of the specific activities within FEI that relate to capital expenditures. This step also provided KPMG with an understanding of FEI's organizational structure and its approach to the acquisition, construction and installation of capital assets.

Step 3: Documented and reviewed regulatory and accounting policy guidance. In this step KPMG researched the guidance provided by various accounting and regulatory authorities on the topic of overhead capitalization. The objective of this step was to ensure that the approach adopted in FEI's capital overhead cost allocation methodology was consistent with U.S. GAAP.

Step 4: Assessed the reasonableness of FEI's capital overhead cost allocation methodology. In this step KPMG assessed the alignment between FEI's methodology against external guidance from regulators. This included a review of the methodology utilized in the survey-based model against FEI's internal policy and internally generated criteria developed to provide an appropriate cost allocation methodology.

Step 5: Assessed the reasonableness of the overhead activities allocated to capital. In this step KPMG assessed the reasonableness of the overhead activities (Department Level) allocated to capital against internal policy and external guidance. Management further clarified and validated survey results with department heads and documented any adjustments.

Step 6: Assessed the reasonableness of the drivers used to allocate overhead costs to capital. In this step KPMG assessed the reasonableness of drivers used in the overhead activities allocated to capital against internal policy and external guidance from regulators.

Step 7: Data Validation of Capital Overhead Capitalization Model. In this step, KPMG conducted the following procedures:

- Reviewed the overhead capitalization model for formula accuracy;
- Validated costs used in the capital overhead cost allocation methodology against the 2018 BCUC approved O&M costs; and
- Validated cost drivers against supporting system records or other corroborative evidence.

Step 8: Assessed the reasonableness of the resulting overhead capitalization rate. In this step KPMG assessed the reasonableness of the resulting overhead capitalization rate against the results of the previous KPMG report filed with BCUC as part of the Company's 2014- 2018 PBR, as well as external guidance from regulators and U.S. GAAP.

6. FEI Overhead Capitalization Methodology and Results

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

FEI has examined the "Survey Model" methodology based on inquiries and other supplemental information with business units to determine the capital overhead rate in Section 6.2.

6.1 Capital Overhead Cost Methodology

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

6.1.1 Develop and Document Criteria for Capital Cost Allocation

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

	Internal FEI Criteria	Detail
1	**Cost Causality**	The identified driver, being it work effort or investment, has a direct correlation to the cost of the services or goods and also has a direct effect on the level of service for that capital project.
2	**Objective Results**	The use of the allocation driver results in an objective allocation amount that is free from undue bias.
3	**Cost Effectiveness**	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
4	**Stability Over Time**	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.
5	**Transparent and Supportable Methodology**	The driver used and the source or basis on how it is determined is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model and other supporting documentation.
6	**Regulatory Precedence**	The cost allocation methodology has been tested and approved through previous regulatory reviews.
7	**Distinguishable from Directly Allocated Capital Costs**	The overhead costs must be distinguished from those that are directly charged to capital.
8	**Accuracy of Underlying Data**	Any data used in the methodology should be accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output.
9	**Flexibility/Adaptability**	The methodology should be able to accommodate future changes in regulatory, accounting and organizational changes with reasonable ease.

6.1.2 Create a Company Questionnaire and Interview Company Officials

In this step, management created a questionnaire in order to better 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 A.

Management then used the questionnaire to interview senior representatives from each department to understand and identify those activities that appear to support, either directly or indirectly, capital projects at FEI. The departments are summarized in Table 1 in Section 6.2.1.

The purpose of this step was to better understand departmental involvement in capital work and the costs attributable to capital work that have not been charged directly to capital. As part of this step:

- A written description of the specific activities within the department that support capital projects was completed; and
- Estimates of the percentage of the approved cost of activities that should be allocated to capitalized overhead were obtained.

6.1.3 Compilation of Data

Management compiled the results of the interviews into a summary model in order to determine an approximate overhead capitalization rate. See Table 1.

6.1.4 Documented Regulatory and Accounting Guidance

The Company researched and provided references to a variety of U.S. accounting guidance on the capitalization of overhead costs. See Section 4.

6.2 Explanation and Results of Survey Methodology

Under the Survey Model, the Company interviewed department heads and senior managers within the corporate functions and business units listed in Table 1. Management sought to understand and identify those company departments that support, either directly or indirectly, capital projects at FEI.

The purpose of this step was to gain an understanding of the specific activities within FEI that may be eligible to have costs allocated to capitalized activities. This step also provided KPMG with a good understanding of FEI's organizational structure and its approach to the acquisition, construction and installation of capital assets. The details of the survey questions used in this approach are provided in Appendix A.

Under the Survey Model, the overhead capitalization rate is determined based on the residual amount of operating business unit and corporate function costs that support capital activities, which have not been allocated to specific capital related activities. That is, this residual is the O&M costs after direct charges performed by departments have been made to capital projects. The assessment is based on labour and non-labour expenses separately for each department. Labour costs are allocated to capital based on a labour time estimate and non-labour costs are allocated based on estimated costs which are related to capital. This determines the overhead capitalization rate. The process is illustrated as follows (Figure 1):

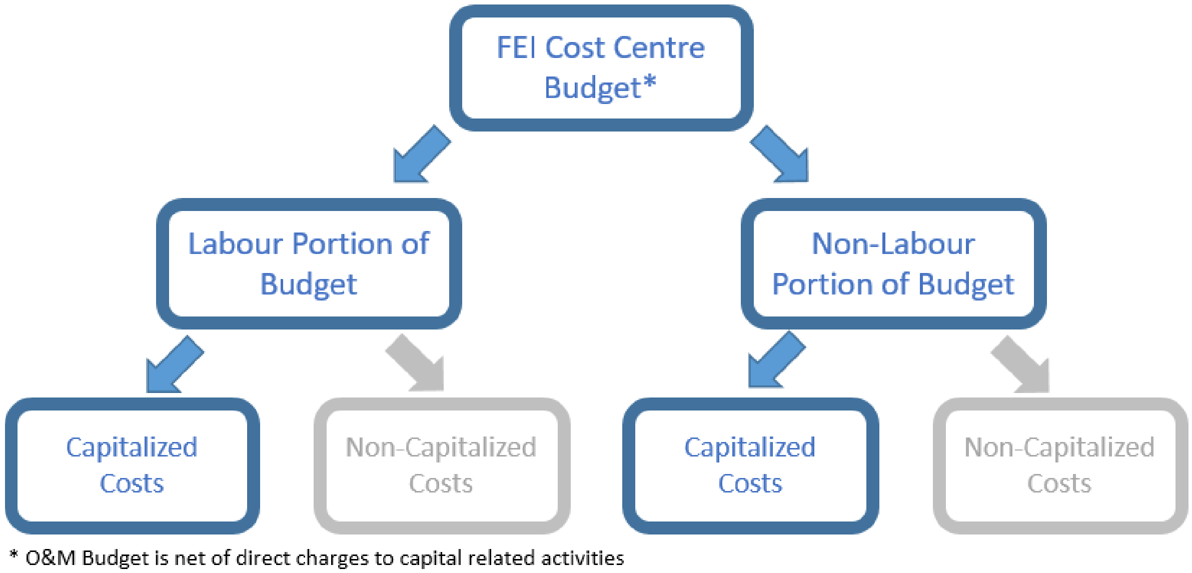


Figure 1: Survey Allocation Illustration

The overall overhead capitalization rate therefore reflects both labour and non-labour components. The rate is expressed as a percentage of O&M costs after direct capital charges, and does not reflect the percentage of O&M costs which have been charged to capital through direct methods.

6.2.1 Survey Model Results

The results of this methodology suggested an overhead capitalization rate of approximately **16 percent**. Table 1 below shows the build-up of this rate for the FEI departments. As can be seen in Table 1, the majority of the capital related overhead dollars is determined by Operations and Engineering.

Table 1: Results of Survey Model (2018)

Department	Total O&M Costs ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	93,839	13,601	14%
Engineering	21,448	10,724	50%
Customer Service and Information Systems	63,244	6,321	10%
Market Developments and External Relations	25,141	5,692	23%
HR, Environment, Health & Safety, and Facilities	24,842	3,599	14%
Finance and Corporate	17,245	2,009	12%
Regulatory, Legal and Operation Supports	15,559	2,235	14%
Energy Supply and Resource Development	14,277	487	3%
Total	**275,595**	**44,668**	**16%**

6.3 Evaluation of Results with Prior Study

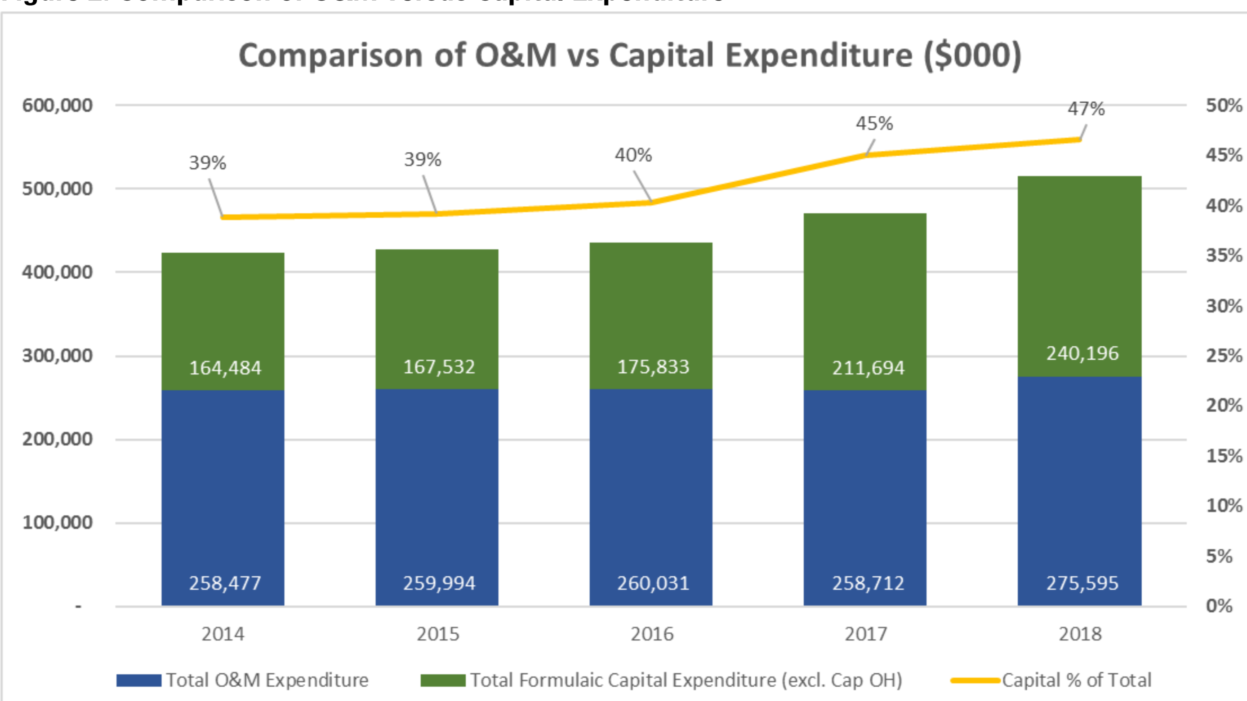
The table below (Table 2) provides a comparison of the results of the Survey Model against the previous study which has been undertaken for the Company.

Table 2: FEI Capital Overhead Ratio Comparison

Current Study (2018)	Previous Study (2013)
16 %	**12 %**

The capitalization rate is higher in the 2018 Study as compared to the 2013 Study. Management recognized that FEI had executed an increasing level of capital activity during the last PBR period. In 2018, FEI's capital expenditures were $76 million or 46% higher than 2014 capital expenditures (Figure 2). This increased level of capital activities aligns with the increase in the capitalized overhead ratio as shown in Table 2. Additionally, FEI had to undertake more upfront activities relating to engineering, planning and external relations to enable the construction of capital projects. This increase in upfront activities was not foreseen in the 2013 Study. Similarly, FEI expects that there will be additional O&M costs that will be incurred to support the capital expenditures during the new MRP period.

Figure 2: Comparison of O&M versus Capital Expenditure



7. KPMG Evaluation

7.1 Overview of Evaluation Conducted

KPMG finds the FEI survey-based capital cost allocation methodology, as detailed in Section 6 of this report, to be a reasonable basis for capitalization of costs related to capital activities that have not been directly charged to capital projects (i.e. overhead capitalization) as examined in the evaluation criteria discussed below. This methodology is consistent with FEI's internally generated evaluation criteria and available regulatory and 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 subsequent assessment in Steps 4 through 8.

In Step 2 of KPMG's approach, a majority of business group interviews were attended by KPMG to gain an understanding of the specific activities and allocation bases (cost drivers) within FEI that may be related to or directly attributable to capital. Section 7.5 of this report details KPMG's review coverage of FEI's O&M costs assessed as eligible for capitalization. This was based on attendance at FEI business group survey interviews and the review of allocation calculations prepared by FEI.

Step 3 of KPMG's approach included a documentation of the guidance provided by various accounting and regulatory authorities. The result of this review is included in Section 4 to this report.

7.2 Evaluation of the Capital Overhead Allocation Methodology

An overhead capitalization methodology should address a number of evaluation criteria that support Company objectives. The Company developed a number of criteria in order to be able to evaluate the appropriateness and reasonableness of the capital overhead methodology which is described in Section 6 of this report.

7.2.1 Reasonability of the Evaluation Criteria Used to Assess FEI Cost Allocation Methodology

In Step 4 KPMG reviewed the internally generated Evaluation Criteria used by FEI to assess the cost allocation methodology. Table 3 provides a summary of the Evaluation Criteria principles that are consistent with Management's assessment principles as described in Section 6.

KPMG finds that the evaluation criteria used to evaluate the capital overhead cost allocation methodology to be appropriate in relation to the accounting guidance and the purpose of the current study.

7.2.2 Reasonableness of the Survey Model Methodology against the internally generated Evaluation Criteria of FEI

In Step 4 KPMG also assessed FEI's capital cost allocation methodology against FEI's internal criteria as outlined in Section 6 of this Study. The assessment criteria are provided in the table below (Table 3).

Table 3: Evaluation of Capital Overhead Allocation Methodology

Evaluation Criteria	Explanation
Cost Causality	The allocation driver has a direct correlation to the cost of service and has a direct effect on the level of service for that capital project.
Objectivity	The use of the allocation driver results in an objective allocation amount that is free from bias.
Cost-Effectiveness	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
Stability over time	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.
Transparent and Supportable Methodology	The driver used and the source or basis on how it is determined is visible to all parties affected. The allocation approach is supported by a defined and documented methodology, model and other supporting documentation.
Regulatory Precedence	The cost allocation methodology has been tested and approved through previous regulatory reviews.
Distinguishable from Directly Allocated Capital Costs	Overhead costs allocated using this methodology are those that are not directly charged to capital and represent overhead activities.
Accuracy of Underlying Data	Any data used in the methodology should be accurate and able to be relied upon. The data should provide an appropriate measure of the underlying volume of activity or output.
Flexibility / Adaptability	The capitalized overhead cost allocation methodology and integrated Excel model facilitates updates, and thus supports the criteria

KPMG believes that the allocation or cost drivers used in this Study meet the evaluation criteria above.

7.3 Qualitative Evaluation of Overhead Activities Allocated to Capital

In Step 5 of the KPMG approach, in order to ensure that the costs being allocated to capital are appropriate under U.S. GAAP, KPMG conducted a 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:

7.3.1 Support for multiple capital 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 managers who supervise multiple projects.

7.3.2 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

7.3.3 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, Finance, Regulatory and Legal.

Certain activities are difficult to directly relate to capital, including for example, Regulatory, Finance and Human Resources as they are removed from actually performing the capital work and represent support functions; however they are integral to putting the plant in service. FEI has applied a methodology to identify where these support activities relate to capital projects.

KPMG finds that, given the very general guidance which is provided under U.S. GAAP, the nature of costs which are being allocated to capital is consistent with the financial accounting framework, as discussed in Section 4.

7.4 Evaluation of Cost Drivers used to Allocate Costs to Capital

In Step 6 KPMG analyzed the nature of the drivers used by FEI to allocate costs to capital projects. The cost drivers under the Survey Model are evaluated below.

Under the Survey Model, capitalized overhead is allocated to capital differently for labour and non-labour costs. The allocation is based on the following:

7.4.1 Labour Time Estimate

For the labour cost component of business operating units and corporate functions, the estimate of labour time incurred in capital asset development related activities was chosen as it most accurately reflects the key component of the overhead cost to be allocated. In developing this estimate, consideration was given to the level of activity reduction in the absence of capital development activities, after direct charges of capital overhead activities.

KPMG notes that the nature of the FEI survey was kept to a relatively high level (usually departmental head) in order to drive an estimate of the corporate function or business unit costs associated with capital activities that had not been directly charged to capital projects.

KPMG finds that, where estimated labour time was used to determine the allocation of the corporate functions and business unit costs to capital projects, the allocation basis applied is consistent with the internally generated Evaluation Criteria established by FEI.

7.4.2 Non-Labour Cost Estimate

For the non-labour cost component of business operating units and corporate functions (e.g. external consultants, equipment, software) the allocation estimation was performed based on management's estimate of the costs which have not been direct charged and are related to capital activities.

KPMG finds that, where management's estimate of the costs was used to determine the allocation of corporate function and business unit costs to capital projects, the allocation basis applied is consistent with the internally generated Evaluation Criteria established by FEI.

7.5 Data Validation - Steps, Results and Limitations

In Step 7 of KPMG's approach, in order to be able to verify the data used in the study, KPMG assessed the methodology and values utilized in the Survey-model methodology approach and reviewed the documented revision values. As previously noted in this report, all figures which have been applied in both models relate to the 2018 O&M.

KPMG performed the following procedures:

7.5.1 Assessment of Underlying Cost Population and Cost Resources

a) verified departmental labour and non-labour budget cost components and agreed to the 2018 O&M costs;

b) verified the total cost population against the 2018 O&M to ensure completeness of departmental cost population; and

c) re-performed the calculations prepared by management to check mathematical accuracy, including capitalization percentages calculated.

7.5.2 Assessment of Allocation Cost Drivers

In conjunction with understanding the allocation cost drivers, KPMG traced the allocation cost drivers to source calculations:

a) verified total expenditures to the 2018 O&M figures;

b) attended interview discussions with department managers where estimated labour cost time was determined. Specifically, we attended interviews related to departments which comprised approximately $240 million out of the $276 million of 2018 BCUC approved O&M costs;

c) reviewed the nature of the non-labour costs in high level to estimate the non-labour cost related to capital; and

d) applied additional specific procedures for departments in order to be able to verify costs, such as agreement to departmental budgets and agreement to department role allocations.

7.6 Assessment of the Resulting Overhead Capitalization Rate

In Step 8, KPMG assessed the methodology and resulting final values confirmed and documented by management and department leads in the Survey-based model against FEI's proposed capital cost allocation methodology.

As described in Section 7.5 of this report, certain procedures were conducted to assess the accuracy of FEI's underlying 2018 O&M BCUC approved costs and the allocation bases used to calculate the allocation of costs to capital within the model.

KPMG finds the FEI Survey-based model and the underlying costs used in the models to be consistent with the cost allocation methodologies as proposed by FEI and guidance related to U.S. GAAP. Based on the results of the Survey Model finalized and documented by management, the estimated overhead capitalization rate is approximately 16 percent.

Appendices

Appendix A – Capitalized Overhead Survey

The following questions were asked of senior management for the survey methodology.

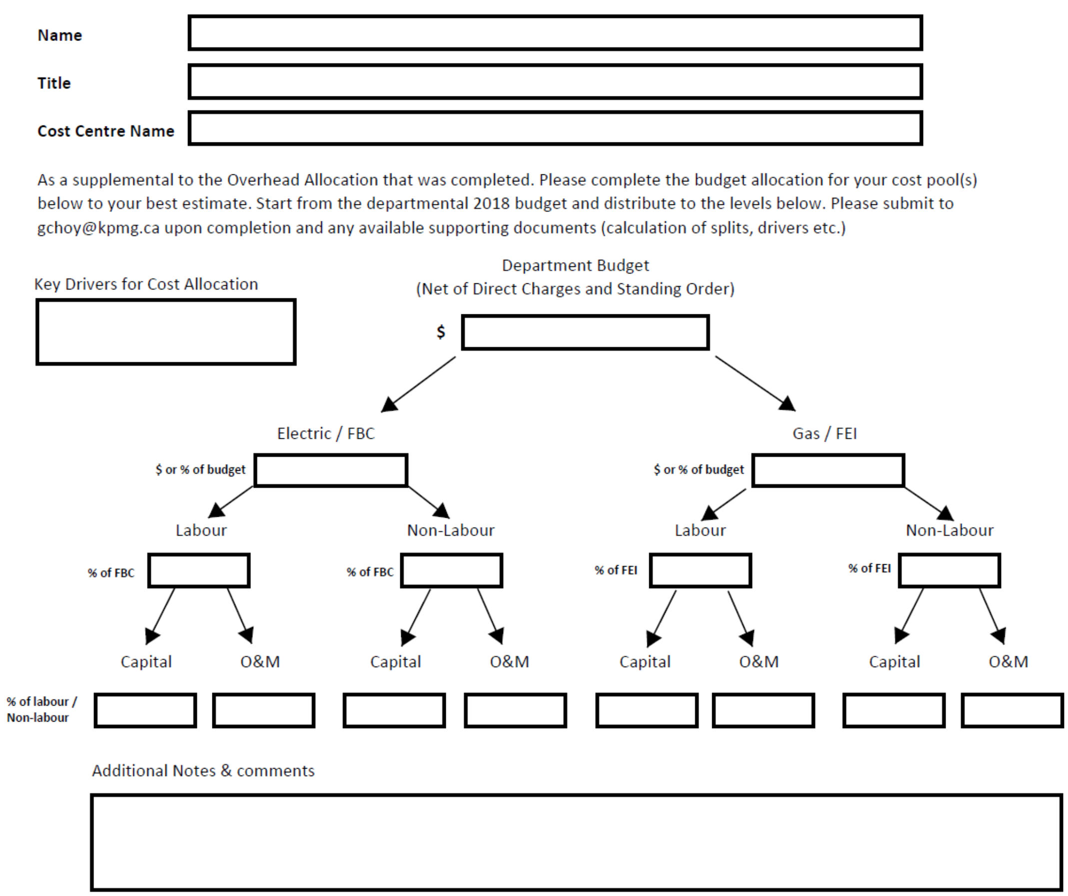
1. Please provide a brief overview of the activities for each of the O&M cost centres that you are responsible for. We are seeking to understand the role of your departments in relation to capital activities.
2. If your O&M cost centres charge any of their costs directly to capital projects, please describe the activities, the amount and that amount as a percentage of the gross O&M 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 2018, 2019 and 2020? If there is an expectation that the amount of direct charge will be changing over time, particularly during the term of the 2020-2024 Performance Based Regulation filing. Please provide a brief explanation for the change.
4. Please describe the costs incurred by your department that are not directly charged to capital, but are still used to indirectly support the capital expenditure programs (i.e. remain within the O&M cost centre).
5. Would the O&M cost center operate with fewer staff and non-labour costs if the company hypothetically ceased to undertake all capital projects? If so – by how much would there be a reduction? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your O&M cost centre staffing be impacted?
6. How would the level of activities in your O&M cost center be impacted if the Company doubled its current level of capital expenditures? If so – by how much would there be an increase?
7. Of the 2018 amounts in each of your O&M cost centres that are not directly charged to capital projects please differentiate the activities (%) split between the following categories: capital and operations and maintenance (O&M).

Gas	Capital	Operating and Maintenance (O&M)
Labour		
Non-Labour		
Electric	Capital	Operating and Maintenance (O&M)
Labour		
Non-Labour		

8. What percentage of your cost centre do you forecast will be spent to indirectly support capital activities (not directly charged to capital and remaining in your O&M cost centre) for 2018 (should be the same as the table in #7 above), 2019 and as part of the 2020-2024 Performance Based Regulation rate filing? If there is an expectation that these indirect activities will be changing over time, please provide a brief explanation for the change.
9. Please describe the primary driver that was used to estimate the percentage of O&M to indirectly support capital activities and 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?

The 2018 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.

Supplemental:


Name

Title

Cost Centre Name

As a supplemental to the Overhead Allocation that was completed. Please complete the budget allocation for your cost pool(s) below to your best estimate. Start from the departmental 2018 budget and distribute to the levels below. Please submit to gchoy@kpmg.ca upon completion and any available supporting documents (calculation of splits, drivers etc.)

Appendix B – Detailed Listing of Accounting Guidance

U.S. GAAP references:

- ASC 360 *Property, Plant and Equipment*
- ASC 720 *Other expenses*
- ASC 970 *Real Estate*
- ASC 980 *Regulated Operations*
- Statement of Position, *Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment* Financial Reporting Executive Committee of the AICPA proposed standard, not adopted.

IFRS references:

- IAS 1 *Presentation of Financial Statements*
- IAS 16 *Property, Plant and Equipment*

Other sources:

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

At KPMG, our values create a sense of shared identity. They define what we stand for and how we do things.

Our values help us to work together in the most effective and fulfilling way. They bring us closer as a global organization.

KPMG

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Appendix D6-2

FBC OVERHEAD CAPITALIZATION METHODOLOGY REVIEW, KPMG

KPMG

FortisBC Inc.

Overhead Capitalization Methodology Review

March 8, 2019

Table of Contents

1. Executive Summary

KPMG LLP ("KPMG") was retained by FortisBC Inc. ("FBC" or "the Company") to assist with their overhead capitalization study (the "Study") to be incorporated in FBC's 2020 to 2024 Multi-Year Rate Plan ("MRP"). 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 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.

For accounting periods commencing after January 1, 2012 FBC has been approved to apply U.S. GAAP pursuant to British Columbia Utilities Commission ("BCUC") Order G-117-11. This framework includes the application of ASC 980 *Regulated Operations*. 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. BCUC has previously confirmed that the FBC is required to have the capitalized overhead study prepared under U.S. GAAP with consideration of ASC 980.

The basis of this Study is the 2018 FBC BCUC approved O&M costs. In the absence of future significant regulatory, capital, accounting and organizational changes, the application of this rate in future periods is expected to continue to be appropriate. In addition, this study will also examine the direct overhead loading methodology applied by FBC.

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 guidance exists on the topic. From this guidance, 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 using a Survey-based Model. The Study utilized the FBC's BCUC approved 2018 FBC O&M (the "2018 O&M") costs. The O&M costs which are allocated to capital through the overhead capitalization rate are net of costs directly charged to capital projects.

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 2018 O&M costs, the costs related to capital activities that have not been directly charged to capital projects, as a percentage of O&M costs, is estimated to be approximately **15 percent**. This result is in line with the overhead capitalization rate derived in the 2013 study (15%).

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

Direct overhead loading:

This study also 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. These methodologies are consistent with FBC's internally generated evaluation criteria and available regulatory and accounting guidance.

Based on the results of the direct overhead loading methodology, a total 2018 O&M of **$5 million** of capital costs are estimated to be related to construction or acquisition of capital projects.

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

2. Purpose of Report

2.1 Project Scope

KPMG was retained by FortisBC Inc. ("FBC" or "the Company") to assist with their overhead capitalization study (the "Study") to be incorporated in FBC's 2020-2024 MRP filing. 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 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.

This report has examined the appropriateness of the capitalization of overhead costs which have not been directly charged to capital and the appropriateness of the direct overhead loading methodology. 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 the Survey-based Model, 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. The methodology has been developed by management to ensure a reasonable allocation of capital related O&M costs to capitalized activities.

2.2 Accounting frameworks

For accounting periods commencing after January 1, 2012 FBC has been approved to apply U.S. GAAP pursuant to BCUC Order G-117-11. This framework includes the application of ASC 980 *Regulated Operations*. Accordingly, the scope of this report is to provide a review of capital overhead cost allocation methodology and the resulting overhead capitalization rate for FBC under the U.S. GAAP financial reporting framework. In addition, this study also examines the direct overhead loading methodology applied by FBC.

The basis of this Study is the 2018 FBC BCUC approved O&M costs. In the absence of future significant regulatory, capital, accounting and organizational changes, the application of this rate in future periods is expected to 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
- 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:

2.3.1 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.

2.3.2 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 2018 approved 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 2018 BCUC approved O&M costs, as provided by management. Our findings and conclusions are therefore limited accordingly.

The information contained herein is for the internal use of FBC management. It is understood that this report will be distributed by FBC externally to the BCUC as part of the regulatory process. 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 Federal Energy and Regulatory Commission's ("FERC") *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** - Capitalized overhead survey
- **Appendix B** - Detailed listing of Accounting Guidance

3. Background

3.1 Application of U.S. GAAP

FEI 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). On July 3, 2014, BCUC approved the continued adoption of U.S. GAAP for regulatory accounting effective January 1, 2015 until FortisBC no longer has an Ontario Securities Commission exemption to use U.S. GAAP or is no longer reporting under U.S. GAAP for financial reporting purposes, whichever is earliest (pursuant to Commission Order G-83-14).

3.2 Previous Capital Overhead Rate Submissions

KPMG previously issued to FBC report dated June 10, 2013 on overhead capitalization methodology in support of the Multi-Year Performance Based Ratemaking Plan for 2014 Through 2018 ("the 2014-2018 PBR"). That 2013 study report was prepared under the U.S. GAAP framework and recommended an overhead capitalization rate as a percentage of total O&M costs of approximately 15% for FBC based on the survey model approach. BCUC directed FBC to use the 15% overhead capitalization rate for the 2014-2018 PBR.

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 (Figure 1):

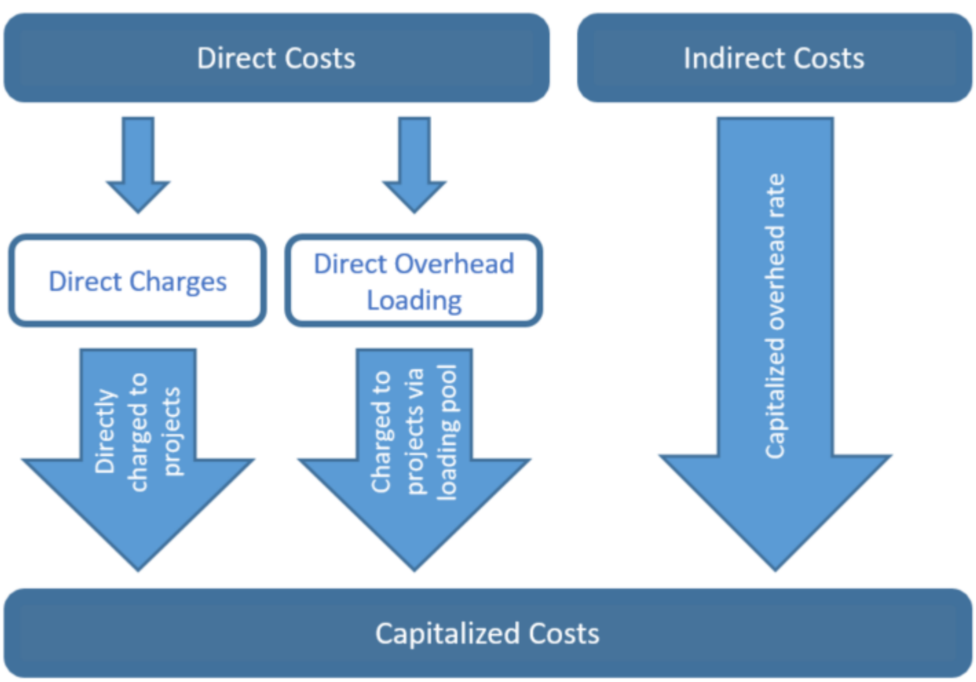


Figure 1: Capital Cost Allocation Overview

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 accounting 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:

– Utilize available U.S. GAAP guidance, including ASC 980 (discussed in Section 4.2);
– Utilize available guidance from BCUC *Uniform System of Accounts Prescribed for Electric Utilities* (discussed in Section 4.3); and
– 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

Due to the absence of detailed guidance for each and every type of capital activity in U.S. GAAP, there is a degree of interpretation required in the application of the standards. As a result, the common principle and underlying methodologies employed by FEI for capitalizing costs related to capital activities that have not been directly charged to capital projects reflects a consistent approach under 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.

There has been no changes to the guidance reviewed in this section for 2018.

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. 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 an 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, KPMG assessed the alignment between FBC's methodology against external guidance from regulators. This included a review of the methodology utilized in the survey-based 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 KPMG assessed the reasonableness of the overhead activities (Department Level) allocated to capital against internal policy and external guidance. Management further clarified and validated survey results with department heads and documented any adjustments.

Step 6: Assessed the reasonableness of the drivers used to allocate overhead costs to capital. In this step KPMG assessed the reasonableness of drivers used in the overhead activities allocated to capital against internal policy and external guidance from regulators.

Step 7: Data validation of capital overhead capitalization model. In this step KPMG conducted the following procedures:

- Reviewed the overhead capitalization models for formula accuracy;
- Validated costs used in the capital overhead cost allocation methodology against the 2018 approved O&M; and
- Validated cost drivers against supporting system records or other corroborative evidence.

Step 8: Assessed the reasonableness of the resulting overhead capitalization rate. In this step KPMG assessed the reasonableness of the resulting overhead capitalization rate against the results of the previous KPMG report filed with BCUC as part of the Company's 2014- 2018 PBR, as well as external guidance from regulators and U.S GAAP.

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 and was designed to provide a supportable basis for the Company's overhead capitalization methodology.

2018 Total FBC Expenditures are as follows:

FBC Total Expenditures = Direct Overhead Loading + Capital Expenditures + O&M costs

FBC has examined the "Survey Model" methodology based on inquiries and other supplemental information with business units to determine the capital overhead rate in Section 6.2.

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

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.

	Internal FBC Criteria	Detail
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 2018 O&M costs. The table shows that approximately of $5 million of overhead costs were allocated to the direct overhead pool and were therefore capitalized.

Table 1: Direct overhead loading results

Department	Function	2018 Direct Overhead Cost ($000s)
Operations – Okanagan	Management and Supervisory time	494
Operations - Kootenay	Management and Supervisory time	360
Project Management Office	Scheduling and administrative support	572
Engineering	Engineering and cost estimating	430
System Planning	T&D system planning & engineering	837
Environment, Health & Safety	Reporting, auditing project work	45
Line Construction	Management and Supervisory time	531
Finance	Accounts payable	87
Procurement & Materials Handling	Supply chain support	500
Distribution Engineering	Capital engineering, design and cost estimating	125
Engineering Standards	T&D Standards development & maintenance	170
System Control	System monitoring & communication	703
Station Capital	Supervisory & administrative support	158
Asset Management	Asset management planning & support	110
Distribution Projects	Local projects tying power from stations to customers	47
	Total	**5,168**

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 Model 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 **$5 million** for the 2018 O&M costs.

The methodology applied is consistent with the methodology of 2013, which resulted in actual direct overhead loadings of $4.7million.

In the absence of future significant regulatory, capital, accounting and organizational changes, the application of the direct overhead loading methodology is expected to 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 the "Survey Model" based on inquiries and other supplemental information with business units to determine the capital overhead rate in Section 7.2.

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

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 Create a Company Questionnaire and Interview Company Officials

In this step, management created a questionnaire in order to better 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 approved cost of activities that should be allocated to capitalized overhead were obtained.

7.1.3 Compilation of Data

KPMG 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 Comparison with Previous Results

The resulting capitalization rate from the current study was compared to the results of the previously approved BCUC capitalization rate from 2013. See results per Table 3.

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 (Figure 2):

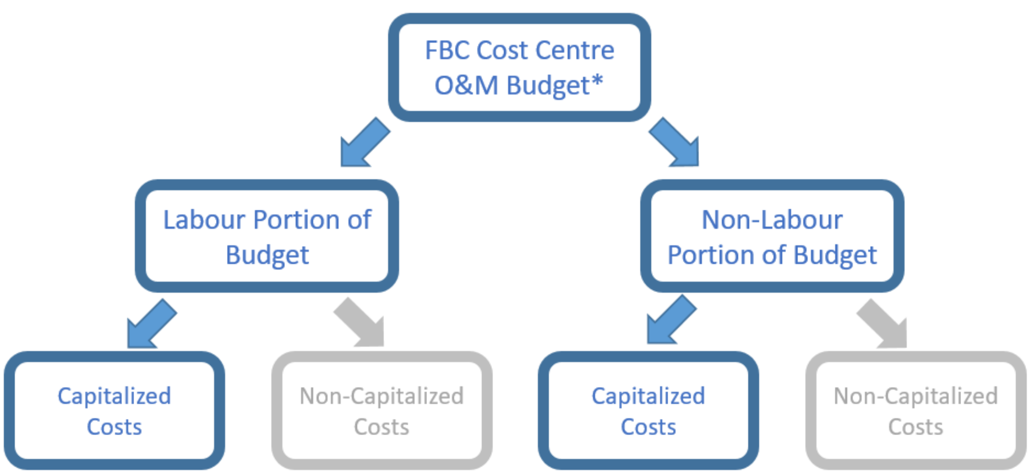


Figure 2: Survey Model Illustration

* FBC Cost centre O&M Budget is net of direct charges and direct overhead loading

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 costs 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 the majority of the capital related dollars is primarily determined by Operations and Information Systems.

Table 2: Results of Survey Model (2018)

Department	Total O&M Costs ($000)	Capital Related ($000)	Capitalization Rate (%)
Operations	23,424	3,888	17%
Engineering	5,379	538	10%
Customer Service and Information Systems	9,928	1,271	13%
Market Developments and External Relations	2,640	570	22%
HR, Environment, Health & Safety, and Facilities	5,971	747	13%
Finance and Corporate	6,545	1,144	17%
Regulatory, Legal and Operation Supports	3,461	305	9%
Energy Supply and Resource Development	1,245	124	10%
Total	**58,592**	**8,587**	**15%**

7.3 Evaluation of Results between Models and with Prior Study

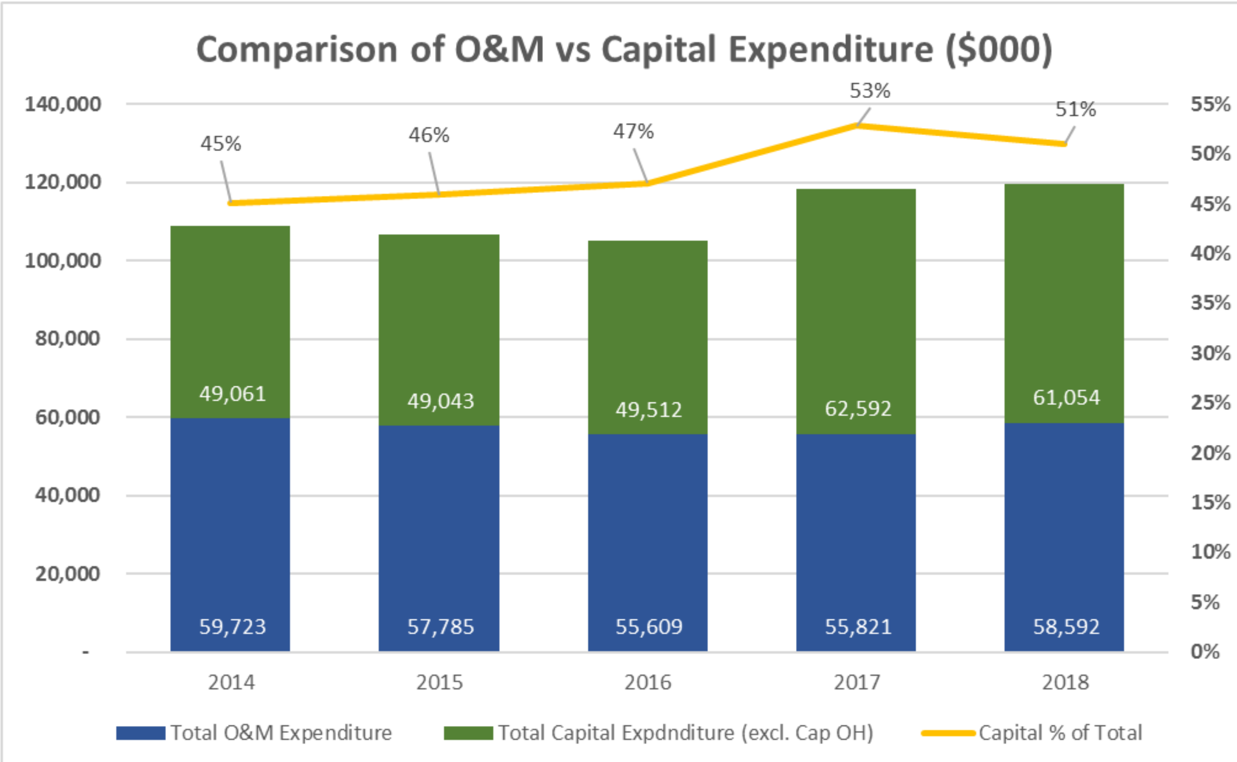
Table 3 below provides a comparison of the results of the Survey Model against the previous studies which have been undertaken for the Company.

Table 3: FBC Capital Overhead Ratio Comparison

Current Study (2018)	Previous Study (2013)
15 %	**15 %**

The capitalization rate in the 2018 Study is consistnet with the 2013 Study. The capitalization rate is further validated by the relatively consistent ratio of capital expenditure to O&M expenditure split since the last study (Figure 3) and taking into consideration that Direct Overhead Loading is part of the company's methodology.

Figure 3: Comparison of O&M versus Capital Expenditure



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 that have not been directly charged to capital projects (i.e. overhead capitalization) as examined in the evaluation criteria discussed below. These methodologies are consistent with FBC's internally generated evaluation criteria and available regulatory and 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 subsequent assessment in Steps 4 through 8.

In Step 2 of our approach, a majority 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 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 of 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 being determined) 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 Reasonableness 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 4 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 Reasonableness of the Survey Model and b) 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 4: Evaluation of Capital Overhead Allocation Methodology

Evaluation Criteria	Explanation
Cost Causality	The allocation driver has a direct correlation to the cost of service and has a direct effect on the level of service for that capital project.
Objectivity	The use of the allocation driver results in an objective allocation amount that is free from bias.
Cost-Effectiveness	The allocation driver is calculated and maintained from readily available information resulting in minimal time and expense.
Stability over time	The allocation methodology can accommodate changes to the allocation driver over time and is scalable.

Evaluation Criteria	Explanation
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 capitalized overhead cost allocation methodology and integrated Excel model facilitates updates, and thus supports the 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.

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 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:

8.4.1 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.

8.4.2 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.

8.4.3 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.

Certain activities are difficult to directly relate to capital, including for example, Regulatory, Finance and Human Resources as they are removed from actually performing the capital work and represent support functions; however they are integral to putting the plant in service. 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 financial accounting framework, 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 cost drivers used by FBC to allocate costs to capital projects. The cost drivers under the direct overhead loading methodology and the Survey-based Model 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.

– **Non-Labour Cost Estimate**

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.

8.6 Data Validation - Steps, Results and Limitations

In Step 7 KPMG assessed the methodology and final values confirmed and documented by management and department leads utilized in the Survey 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 the Survey and the direct overhead loading models relate to the 2018 O&M costs.

KPMG performed the following procedures:

8.6.1 Assessment of underlying cost population and cost resources

a) verified departmental labour and non-labour budget cost components and agreed to the 2018 O&M costs;

b) verified the total cost population against the 2018 O&M costs to ensure completeness of departmental cost population; and

c) re-performed the calculations prepared by management to check mathematical accuracy, including capitalization percentages calculated.

8.6.2 Assessment of allocation bases (cost drivers)

In conjunction with understanding the allocation bases, KPMG traced the allocation bases to source calculations. As two models were used, the procedure differed slightly.

a) For the direct overhead loading process KPMG:

   i. held discussions with management to review the cost allocations which had been applied; and

   ii. re-performed the calculations prepared by management of the direct overhead cost pool.

b) For the Survey Model KPMG:

   i. verified total expenditures to the 2018 O&M costs;

   ii. attended interview discussions with department managers where estimated labour cost time was determined. Specifically, we attended interviews related to departments which comprised approximately $50 million out of the $59 million, or 89%, of 2018 approved O&M costs;

   iii. reviewed the nature of the non-labour costs in high level to estimate the non-labour cost related to capital; and

   iv. applied additional specific procedures for departments in order to be able to verify costs, such as agreement to departmental budgets; agreement to department role allocations.

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 2018 O&M 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 finalized and documented by management, 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 $5 million for 2018 O&M costs.

Appendices

Appendix A - 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 O&M 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 O&M 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 O&M 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 2018, 2019 and 2020? If there is an expectation that the amount of direct charge will be changing over time, particularly during the term of the 2020-2024 Performance Based Regulation filing. Please provide a brief explanation for the change.

4. Please describe the costs incurred by your department that are not directly charged to capital, but are still used to indirectly support the capital expenditure programs (i.e. remain within the O&M cost centre).

5. Would the O&M cost center operate with fewer staff and non-labour costs if the company hypothetically ceased to undertake all capital projects? If so – by how much would there be a reduction? In the absence of any capital activities; if the Company were to simply operate and maintain the current system(s) would your O&M cost centre staffing be impacted?

6. How would the level of activities in your O&M cost center be impacted if the Company doubled its current level of capital expenditures? If so – by how much would there be an increase?

7. Of the 2018 amounts in each of your O&M cost centres that are not directly charged to capital projects please differentiate the activities (%) split between the following categories: capital and operations and maintenance (O&M).

Gas	Capital	Operating and Maintenance (O&M)
Labour		
Non-Labour		
Electric	Capital	Operating and Maintenance (O&M)
Labour		
Non-Labour		

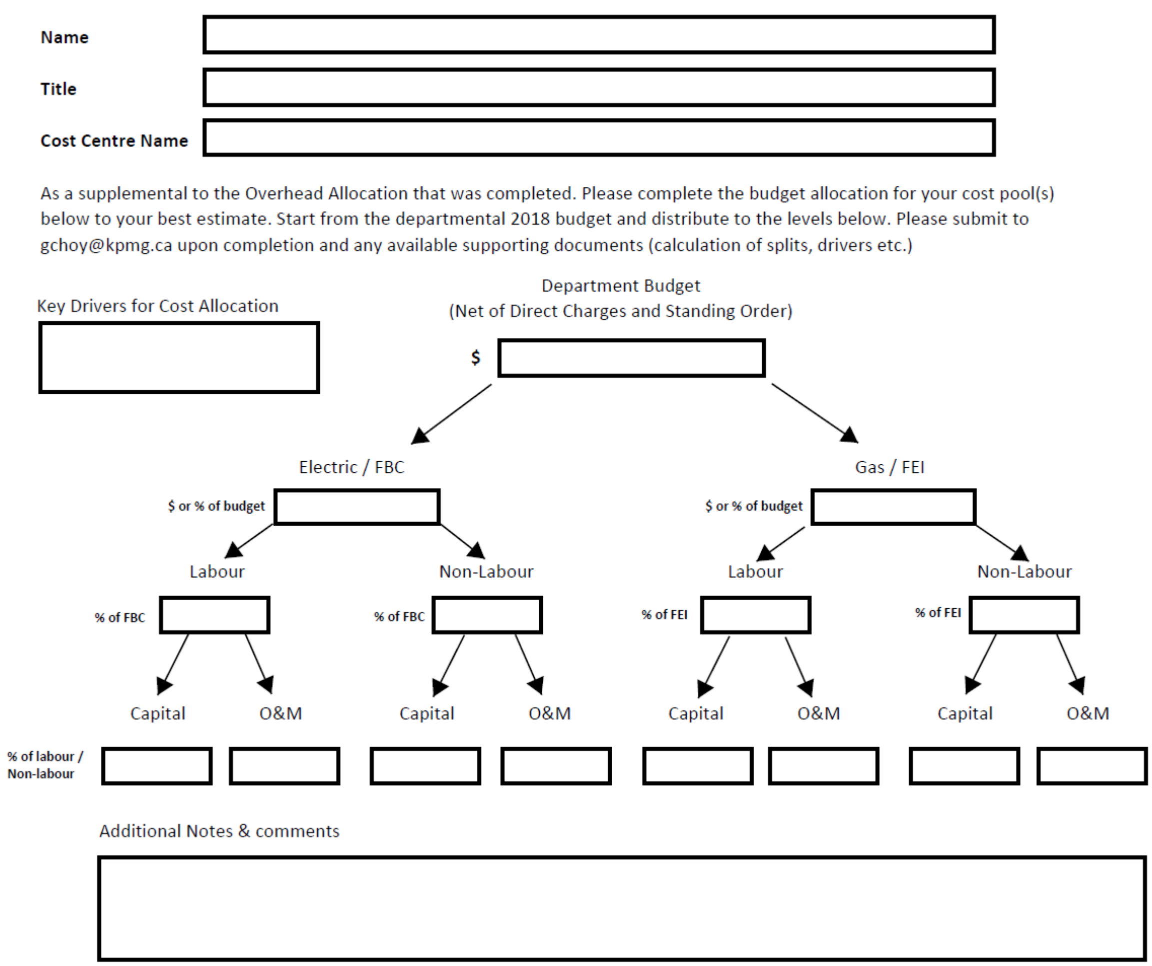
8. What percentage of your cost centre do you forecast will be spent to indirectly support capital activities (not directly charged to capital and remaining in your O&M cost centre) for 2018 (should be the same as the table in #7 above), 2019 and as part of the 2020-2024 Performance

Based Regulation rate filing? If there is an expectation that these indirect activities will be changing over time, please provide a brief explanation for the change.

9. Please describe the primary driver that was used to estimate the percentage of O&M to indirectly support capital activities and 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?

The 2018 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.

Supplemental:



Name

Title

Cost Centre Name

As a supplemental to the Overhead Allocation that was completed. Please complete the budget allocation for your cost pool(s) below to your best estimate. Start from the departmental 2018 budget and distribute to the levels below. Please submit to gchoy@kpmg.ca upon completion and any available supporting documents (calculation of splits, drivers etc.)

Appendix B – 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*

At KPMG,
our values create
a sense of shared
identity. They define
what we stand for
and how we do things.

Our values help us
to work together in
the most effective
and fulfilling way.
They bring us
closer as a
global organization.

KPMG

kpmg.ca

Appendix E

DRAFT ORDERS

British Columbia Utilities Commission
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Vancouver, BC Canada V6Z 2N3
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TF: 1.800.663.1385
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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Multi-Year Rate Plan for 2020 through 2024

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On March 11, 2019, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC or the Companies) applied to the British Columbia Utilities Commission (BCUC) for approval of a Multi-year Rate Plan (Proposed MRP) for each of FEI and FBC for the years 2020 through 2024, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA) (Application);

B. The Application seeks approval of a framework for each of FEI and FBC for how rate setting will occur over the upcoming five years, including incentive mechanisms, an innovation fund, a forecast of capital expenditures, and service quality indicators;

C. The Application also seeks approval of the deferral accounts associated with the proposed framework, and updated depreciation rates, capitalization rates and other supporting studies; and

D. On DATE, FortisBC held a workshop to review the key aspects of the Application;

E. On DATE, FortisBC responded to information requests from the BCUC and registered interveners;

F. On DATE, the BCUC held a procedural conference to determine the remaining process steps for the review of the Application;

G. On DATE, the BCUC issued Order G-xx-xx determining the remaining process steps for the review of the Application, including workshops on particular areas of interest and written submissions from the parties;

H. On DATES, the BCUC held workshops to consider particular areas of interest;

I. On DATE, FortisBC filed its final argument;

J. On DATE, interveners filed their final arguments;

K. On DATE, FortisBC filed its reply argument;

L. The BCUC has completed its review of the Application and finds that approval is warranted.

NOW THEREFORE pursuant to sections 59-61 of the *Utilities Commission Act*, the BCUC orders as follows:

1. For FEI, the BCUC approves the following:

    a. The rate setting mechanisms set out in Section C1 and in Table C1-1 of the Application for setting delivery rates for the years 2020 through 2024, including:

        i. A five-year term 2020 to 2024 as described in Section C1.2;

        ii. Use of an index-based approach to Base O&M and Growth capital, incorporating:

            1. A 2019 Base O&M per customer of $251, as described in Section C2.4, Table C2-1;

            2. A 2019 Growth Capital per customer of $3,811, as described in Section C3.3.1, Table C3-3;

            3. An inflation factor as set out in Section C1.3;

            4. A forecast of customer growth as set out in Section C1.4;

            5. A true up of the spending envelope in the following year(s) as set out in Section C1.4;

        iii. The level of forecast Sustainment and Other capital to be incorporated in rates over the term of the Proposed MRP as set out in Section C3.3.2, Table C3-7;

        iv. Flow through treatment for the items described in Section C4 and Table C4-1;

        v. Exogenous factor treatment as described in Section C4.10;

        vi. The 13 Service Quality Indicators (nine SQIs with a target benchmark and four informational measures) listed in Section C7.2, Table C7-1;

        vii. Half of ROE variances before targeted incentives to be shared with customers as set out in Section C8.2;

        viii. Targeted incentives as set out in Section C8.3, Table C8-1;

        ix. An efficiency carryover mechanism as described in Section C1.5;

        x. Off ramps as described in Section C1.6; and

        xi. Annual review process as described in Section C1.7.

    b. The creation and modification of deferral accounts as set out in Section C5 of the Application and summarized in Table A2-1, effective January 1, 2020.

c. The changes to the following supporting studies to be used in the determination of rates for FEI effective January 1, 2020:

    i. Modification to the approved Lead Lag days as set out in Table D3-1, Section D3.2;

    ii. Depreciation rates in the amounts set out in Table D2-3 in Section D2;

    iii. Net salvage rates in the amounts set out in Table D2-4 in Section D2; and

    iv. The capitalized overhead rate of 16 percent as set out in Section D6.4.

d. The allocation methodology of costs for corporate services between FortisBC Holdings Inc. (FHI) and FEI and for Shared Services as between FEI and FBC, as reflected in the Corporate Services Agreement and Shared Service Agreements as described in Sections D4 and D5 of the Application.

e. The Innovation Fund basic charge rate rider of $0.40 as described in Section C6.6, Table C6-3.

f. The recording of the interconnection costs for FEI's seven interconnection facilities identified in the 2010 Biomethane Application in the Biomethane Variance Account (BVA) as described in Section C4.4.2.3 and Appendix B9.

2. For FBC, the BCUC approves the following:

    a. The rate setting mechanisms set out in Section C1 and in Table C1-1 of the Application for setting rates for the years 2020 through 2024, including:

        i. A five-year term 2020 to 2024 (Section C1.2);

        ii. Use of an index-based approach to Base O&M, incorporating:

            1. A 2019 Base O&M per customer of $416, as described in Section C2.5, Table C2-14;

            2. An inflation factor as set out in Section C1.3;

            3. A forecast of customer growth as set out in Section C1.4;

            4. A true up of the spending envelope in the following year(s) as set out in Section C1.4;

        iii. The level of forecast capital to be incorporated in rates over the term of the Proposed MRP as set out in Table C3-21 in Section C3.4.1;

        iv. Flow through treatment for the items described in Section C4 and Table C4-1;

        v. Exogenous factor treatment as described in Section C4.10;

        vi. The 12 Service Quality Indicators (8 SQIs with a target benchmark and 4 informational measures) listed in Section C7.3, Table C7-5;

        vii. Half of ROE variances before targeted incentives to be shared with customers as set out in Section C8.2;

viii. Targeted incentives as set out in Section C8.3, Table C8-1;

ix. Efficiency carryover mechanism as described in Section C1.5;

x. Off ramps as described in Section C1.6; and

xi. Annual review process as described in Section C1.7.

b. The creation and modification of deferral accounts as set out in Section C5 and summarized in Table A2-2, effective January 1, 2020.

c. The changes to the following supporting studies to be used in the determination of rates for FBC effective January 1, 2020:

i. Modification to the approved Lead Lag days as set out in Table D3-2, Section D3.3;

ii. Depreciation rates in the amounts set out in Table D2-10 in Section D2;

iii. Net salvage rates in the amounts set out in Table D2-12 in Section D2; and

iv. The capitalized overhead rate of 15 percent as set out in Section D6.5.

d. The allocation methodology of costs for corporate services between FortisBC Holdings Inc. (FHI) and FBC and for Shared Services as between FEI and FBC, as reflected in the Corporate Services Agreement and Shared Service Agreements as described in Sections D4 and D5 of the Application.

e. The Innovation Fund basic charge rate rider of $0.30 as described in Section C6.6, Table C6-3.

f. The Power Supply Incentive (PSI) as described in Section C8.3.7 and Appendix C7.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

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British Columbia
Utilities Commission

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Multi-Year Rate Plan for the years 2020 through 2024

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On March 11, 2019, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC or the Companies) applied to the British Columbia Utilities Commission (BCUC) for approval of a proposed Multi-year Rate Plan for the years 2020 through 2024, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA) (Application);

B. The Application seeks approval of a framework for how rate setting for the Companies will occur over the upcoming five years, including incentive mechanisms, an innovation fund, a forecast of capital expenditures, and service quality indicators;

C. The Application also seeks approval of the deferral accounts associated with the proposed framework, and updated depreciation rates, capitalization rates and other supporting studies; and

D. The BCUC considers that establishing a preliminary Regulatory Timetable and a Procedural Conference is warranted.

NOW THEREFORE the BCUC orders as follows:

1. A preliminary Regulatory Timetable as set out in Appendix A to this order is established.

2. A Procedural Conference regarding the regulatory process for the remaining review of the Application will be held on Tuesday, July 9, 2019, commencing at 9:00 am in the BCUC Hearing Room on the 12th floor, 1125 Howe Street, Vancouver, BC.

3. FortisBC must publish, as soon as possible, the Public Notice, attached as Appendix B to this Order, in the Vancouver Sun, the Province, and other such appropriate local news publications to provide adequate notice to those parties who may have an interest in or be affected by the Application.

4. The Application, together with any supporting materials, will be available for inspection at FortisBC Energy Inc., 16705 Fraser Highway, Surrey, BC, V4N 0E8 and FortisBC Inc., Suite 100, 1975 Springfield Road, Kelowna, BC V1Y 7V7. The Application and supporting materials also will be available on the FortisBC website at www.fortisbc.com and on the BCUC website at www.bcuc.com.

5. Interveners who wish to participate in the regulatory proceeding are to register with the BCUC by completing a Request to Intervene Form, available on the BCUC's website at http://www.bcuc.com/Registration-Intervener-1.aspx by the date established in the Regulatory Timetable attached as Appendix A to this order and in accordance with the BCUC's Rules of Practice and Procedure attached to Order G-1-16.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner

Attachment

FortisBC Energy Inc. and FortisBC Inc.
Application for Approval of a Multi-Year Rate Plan for the years 2020 through 2024

REGULATORY TIMETABLE

ACTION	DATE (2019)
FEI Publishes Notice	Week of April 8
Intervener Registration	Thursday, April 18
Workshop on Key Elements	Wednesday, May 1
BCUC Information Request (IR) No. 1	Wednesday, May 15
Intervener IR No. 1	Wednesday, May 23
Companies' Responses to IRs No. 1	Monday, June 17
Procedural Conference	Tuesday, July 9
Further Process	To be determined

APPENDIX B
to Order G-xx-xx

PUBLIC NOTICE

FortisBC Energy Inc. and FortisBC Inc. Application for a Multi-Year Rate Making Plan

On March 11, 2019, FortisBC Energy Inc. and FortisBC Inc. (collectively FortisBC or the Companies) filed an Application for approval of a proposed multi-year rate plan for the years 2020 through 2024, pursuant to sections 59 to 61 of the *Utilities Commission Act.* The Application seeks approval of a framework for how rate setting for the Companies will occur over the upcoming five years, including incentive mechanisms, an innovation fund, a forecast of capital expenditures, and service quality indicators. The Application also seeks approval of the deferral accounts associated with the proposed framework, and updated depreciation rates, capitalization rates and other supporting studies.

HOW TO PARTICIPATE

There are a number of ways to participate in a matter before the BCUC:

- **Submit a letter of comment**
- **Register as an interested party**
- **Request intervener status**

For more information, or to find the forms for any of the options above, please visit our website or contact us at the information below.

http://www.bcuc.com/forms/request-to-intervene.aspx

All submissions received, including letters of comment, are placed on the public record, posted on the BCUC's website and provided to the Panel and all participants in the proceeding.

NEXT STEPS [If necessary]

1. **Intervener registration** Persons who are directly or sufficiently affected by the BCUC's decision or have relevant information or expertise and that wish to actively participate in the proceeding can request intervener status by submitting a completed Request to Intervene Form by Wednesday, April 24, 2019.
2. **Procedural conference** A procedural conference is scheduled to take place on Wednesday, June 12, 2019, commencing at 9:00am in the BCUC Hearing Room, Twelfth Floor, 1125 Howe Street, Vancouver, BC. At the procedural conference, the BCUC will hear from the applicant and registered interveners on the appropriate regulatory process. Members of the public are welcome to attend.

GET MORE INFORMATION

All documents filed on the public record are available on the "Current Proceedings" page of the BCUC's website at *www.bcuc.com*.

If you would like to review the material in hard copy, or if you have any other inquiries, please contact Patrick Wruck, Commission Secretary, at the following contact information.

British Columbia Utilities Commission
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